Comprehensive Assessment and Report

Part I

Energy Resources and Infrastructure of Southwest Connecticut

Prepared by the

Working Group on Southwest Connecticut

and the

Task Force on Long Island Sound

Pursuant to

Public Act 02-95 and Executive Order No. 26

January 1, 2003

At Eastern Connecticut State University

Institute for Sustainable Energy
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INTRODUCTION

Since 1992, the Federal Energy Regulatory Commission (FERC) has issued a series of orders designed to encourage competition in the natural gas and electricity industries. In the past few years, New England's electric industry has witnessed a fundamental transformation. FERC's issuance of Order Nos. 888 and 889 in 1996 removed impediments to competition in the wholesale electric market, and set forth standardized rules to promote open access, non-discriminatory electric transmission service. In 1997, New England's independent system operator (ISO New England, Inc., or ISO-NE) was created to administer the deregulated wholesale markets for the New England Power Pool (NEPOOL). In 1998, Connecticut joined other states in restructuring its electric utility industry. Public Act 98-28, An Act Concerning Electric Restructuring (PA 98-28), authorized competition in electric generation services starting in 2000. Connecticut's landmark legislation effectively required Connecticut's investor-owned utilities to divest generating assets, provided for stranded cost recovery, and mandated reductions in retail electric rates, among other things. FERC Order No. 2000, FERC's recent nationwide Standard Market Design (SMD) Notice of Proposed Rulemaking (NOPR), and FERC's most recent approval of SMD for New England are all designed to complete the transition to a standardized set of rules governing locational pricing and scheduling of wholesale power supply.

Since 2000, new natural gas supplies from Atlantic Canada off the coast of Sable Island, Nova Scotia, have been flowing into New England. The favorable reserve outlook off the coast of Sable Island portends continued natural gas production in the years ahead, as well as expansion of the pipelines serving New England and New York. Although Connecticut's gas utilities, power suppliers, and end users benefit from the new supply as well as the heightened competition among rival producing basins, Connecticut is placed at the crossroads of the pathway from Canada to New York. Two rival gas pipelines have petitioned FERC for certificate authority to cross Long Island Sound in order to reach the market centers on Long Island and New York City. One pipeline company, Islander East, has already received certificate authority from FERC to cross Long Island Sound.

Since New England's vertically integrated electric utilities began the process of divesting their generation assets in 1997, the region has experienced a building boom of new power plants, virtually all natural gas fired. Perceived electricity shortfalls in parts of New England have turned into relative abundance in just a few years due to investment in about 10,500 MW of new generation capacity, and in pipeline infrastructure linking New England with Atlantic Canada.

New England's energy abundance is not distributed uniformly across the region, however. The bulk power system in southwestern Connecticut (SWCT), including the Norwalk-Stamford sub-area (NOR), does not meet established reliability criteria due to a combination of robust demand, older generation within SWCT, and inadequate transmission capacity linking SWCT to the backbone of the transmission network in New England. In the dynamic Regional Transmission Expansion Plan (RTEP) process led by ISO-NE, SWCT has been designated as a Deficient Load Pocket. In light of the severity of the transmission constraint in SWCT and the amount of electric load potentially at-risk, ISO-NE, FERC, and the Department of Public Utility Control (DPUC) have expressed concern over transmission reliability in SWCT. Moreover, in the RTEP02 Report, transmission congestion costs in New England arising primarily from bottlenecks in SWCT are estimated to range from $50 million to $300 million in 2003. While congestion costs are expected to decrease in 2004/05, ISO-NE expects estimated congestion costs to rise thereafter, absent reinforcements to the transmission system in SWCT. Over the forecast period 2003 through 2007, ISO-NE estimates congestion costs caused by constraints in SWCT, including NOR, to be about 90% of the total congestion costs throughout New England.

To alleviate the bottlenecks in SWCT and to promote transmission reliability, Connecticut Light and Power (CL&P) has filed an application with the Connecticut Siting Council (the Siting Council) to construct a 345 kV transmission line from Bethel to Norwalk. CL&P expects to file another application in 2003 in order to complete a 345 kV loop from Norwalk to Beseck Junction in Wallingford. CL&P's preferred overhead alternative for the Bethel-Norwalk project would utilize the existing 115 kV transmission line right-of-way (ROW) along the 20-mile path. The existing 115 kV transmission line and the new 345 kV conductors would be combined onto a new set of structures which would be taller than the existing structures. Also, the ROW would need to be widened along much of the route. CL&P proposed two alternative designs that either place the 345 kV transmission line underground or relocate the existing 115 kV transmission line underground to provide room for the 345 kV transmission line on the existing expanded ROW. The underground lines would utilize existing public roadways. The Five Towns (Bethel, Redding, Wilton, Weston and Norwalk) have proposed an alternative that consists of two new 115 kV transmission lines installed underground between Norwalk and Bethel.

Alternatives to high voltage transmission lines must be considered as part of the balanced approach to alleviating the transmission congestion problems in SWCT. Conservation and load management (C&LM) programs implemented by CL&P and United Illuminating Co. (UI), and ISO-NE's Load Response Program (LRP) reduced peak load in SWCT by approximately 2.7% in 2002. Technology advances in distributed generation (DG), transmission and demand side management have the potential to contribute to the long-term energy balance in SWCT. Clean, small-scale DG alternatives, such as fuel cells and cogeneration offer promising complements to more conventional infrastructure solutions oriented around high voltage transmission lines and large-scale generation projects.

Maintaining the balance between Connecticut's energy needs and protection of its natural resources is achieved through the interplay of utility regulation and strong environmental protection laws. Created in 1971, the Siting Council is responsible for balancing the statewide public need for adequate and reliable services at the lowest reasonable cost to consumers, with the need to protect the state's environment and ecology, including ecological, scenic, historic, and recreational resources.

Under deregulation, the competitive market determines the project type, size, and location of generating units and merchant transmission lines. There is no adequate comprehensive, policy-driven energy planning process emphasizing long term least cost analysis and environmental management in Connecticut. With respect to the siting of energy facilities, including transmission lines, the existing environmental review process was not necessarily designed to address the cumulative impacts of competitive infrastructure projects in a deregulated market. The Siting Council considers cumulative impacts of a proposed project, but must review each new proposed project sequentially based on the merits of an individual project. The Siting Council's authority to consider a comparison of environmentally, technically, and economically practical alternative routes and sites may not include all competing proposed projects. The Department of Environmental Protection (DEP) reviews each new proposed project based on the merits of an individual project. Its ability to review the cumulative environmental impacts of multiple projects is presently limited. Thus, the current environmental review framework could better facilitate the assessment of cumulative environmental impacts and does not have a mechanism to gauge adequately the relative merits of competing projects.

PROCESS

Governor John G. Rowland's Executive Order No. 26, issued April 12, 2002 (provided as Appendix A), and Public Act 02-95 (PA 02-95, provided as Appendix B) signed into law on June 3, 2002, raise questions about current energy planning and management. PA 02-95 established a Working Group and a Task Force to examine these matters and to prepare a comprehensive assessment and report.

The Working Group's mission stems from concerns regarding CL&P's application before the Siting Council to construct the Bethel-Norwalk 345 kV transmission line. PA 02-95 defers final decision on this application until February 1, 2003, after the Working Group completes its assessment. Under Section 2 of PA 02-95, the Working Group is specifically charged with evaluating:

(A) The economic considerations and environmental preferences and appropriateness of installing such transmission lines underground or overhead;

(B) the feasibility of meeting all or part of the electric power needs of the region through distributive generation; and

(C) the electric reliability, operational and safety concerns of the region's transmission system and the technical and economic

feasibility of addressing these concerns with currently available transmission system equipment.

In addition, the Working Group must also "include recommendations for any legislative changes deemed necessary as a result of such assessment."

The Task Force is focused on the protection of Long Island Sound, one of the largest marine estuaries on the east coast. In the months leading up to passage of PA 02-95, a number of proposals for both electric transmission cables and natural gas pipelines crossing Long Island Sound was placed before the Siting Council and the DEP. PA 02-95 imposed a one year moratorium, preventing any state agency from considering or rendering a final decision on new applications relating to electric, natural gas, or telecommunications crossings of Long Island Sound.

Pursuant to Section 3 of PA 02-95, the Task Force is charged to obtain information as to the current status of electric, gas, and telecommunications lines crossing or within Long Island Sound; evaluate the documented and the potential environmental impacts of such lines; and assess the contribution of such lines to the reliability and operation of the state's and the region's energy and telecommunications infrastructure.

For over six months, the Working Group and the Task Force convened on a regular basis in a series of collaborative meetings organized and chaired by the Institute for Sustainable Energy (ISE) at Eastern Connecticut State University. Levitan & Associates, Inc. (LAI) was retained to assist both parties in this process.

This document is intended to comply with the legislative mandate for the Working Group to develop a comprehensive assessment and report that addresses each element of PA 02-95 Section 2 by January 1, 2003. The Task Force has a similar mandate to address the elements in PA 02-95 Section 3. The Working Group and Task Force objectives are interrelated – both must address energy reliability within the integrated New England electric grid and gas pipeline network. The energy infrastructure and environmental resources are not bounded by the shoreline of Connecticut or the political boundaries of the state.

This report also seeks to improve the process for energy planning and management, in particular, regarding transmission solutions in SWCT. The Working Group and the Task Force jointly developed convergent recommendations that are presented and supported in this Comprehensive Assessment and Report – Part I. Central to this work, the Working Group and Task Force jointly present a framework intended to assure an evaluation of energy project proposals that appropriately balances the need for cost-effective and reliable energy resources with Connecticut's commitment to protect its environmental resources. This Comprehensive Assessment and Report – Part I also presents recommendations to improve coordination of state energy projects in the deregulated electric and gas markets. The Task Force will issue a separate report no later than June 3, 2003 to address the complex environmental issues and make recommendations related to the utilization of Long Island Sound as required by PA 02-95 Section 3.

WORKING GROUP CONCLUSIONS

In accordance with the requirements of PA 02-95, the Working Group has addressed each of the three elements of Section 2. The Working Group's conclusions with respect to each element are based on the extensive information obtained during the collaborative meetings and summarized in Section 2 of this report.

(A) The economic considerations and environmental preferences and appropriateness of installing such transmission lines underground or overhead;

The Working Group examined the relative economics of overhead and underground transmission lines both for the specific CL&P Bethel-Norwalk transmission line expansion, and for electric transmission line projects in general. The expected capital cost of constructing the Bethel-Norwalk underground transmission line alternatives would be higher than the overhead line proposal. The cost differential is project and location-specific, and depends on a number of factors, including the length of the route, subsurface conditions, terrain, cost of ROW acquisition, crossings of major roadways or other structures, and other construction-related constraints.

Underground transmission lines in public roadways will minimize the primary long-term impacts to visual, natural, and cultural resources because they are not visible and require less land clearing and alteration of the natural topography, vegetation, and wildlife habitat. Underground transmission lines constructed in undeveloped areas, *i.e.* cross-country, would likely have greater natural resource impacts than an overhead line in the same path. However, construction of both underground and overhead transmission lines gives rise to short and long term impacts associated with road building, excavation, erosion and sedimentation, noise, and traffic. Underground transmission lines within developed public roadways would likely have the least impacts to natural and cultural resources.

Under existing state law, the Siting Council can only certify projects that will meet the energy reliability needs of the state and the region, while minimizing substantial adverse impacts to the state's environmental resources at the lowest reasonable cost to ratepayers. The Working Group endorses the Siting Council's request for CL&P to provide additional alternatives to the 345 kV proposal. Such alternatives may include route variations, use of lower height structures, and the use of underground technologies. The Siting Council will evaluate these alternatives to determine their consistency with the Working Group's report and assessment, and existing state policy.

(B) the feasibility of meeting all or part of the electric power needs of the region through distributive generation; and

The Working Group concludes that DG should be part of a rational response to addressing SWCT's electricity needs. However, DG cannot be the exclusive solution. Barriers that impede penetration of DG in the market include impacts to air quality from oil-fired generators, coordination with grid operations, constraints on the existing infrastructure for more environmentally-clean fuel supplies such as natural gas, limits on the distribution system interconnection capacity, cost of backup electric service and tariff structure, lack of technology maturation, interconnection standards, manufacturing economies of scale for innovative technologies, and financial barriers (capital and operating) hindering consumer interest in making commitments to DG. Moreover, air emissions, regional environmental consequences, and environmental justice concerns related to DG implementation are additional issues for resolution as part of any comprehensive response in SWCT.

Connecticut has established programs such as the Connecticut Clean Energy Fund (CCEF) to promote the development of clean and efficient DG technologies. The Working Group submits that Connecticut can undertake further measures to align the wholesale and retail markets to advance the business case for DG, in order for DG to become an expanded part of the state's energy mix. The Working Group suggests that the legislature and/or state agencies weigh initiatives including administration of a conservation charge on natural gas, rationalized regional interconnection standards and backup tariff rate structure, time-of-use and/or locational pricing to send appropriate market signals, a pilot program for expanded demand side responses, and presumptive standards for air emission limits.

(C) the electric reliability, operational and safety concerns of the region's transmission system and the technical and economic feasibility of addressing these concerns with currently available transmission system equipment.

The reliability, operational, and safety concerns of the transmission infrastructure serving SWCT and all of Connecticut have been examined by ISO-NE, the DPUC, and the state's utilities. The Working Group concurs that SWCT is a deficient load pocket requiring additional resources in order to meet bulk power reliability criteria. The current energy infrastructure in SWCT is not adequate to serve this area as it continues to experience development and economic expansion. The limits of the existing transmission system and available generation have required the installation of emergency generation and for ISO-NE to prepare for load shedding to prevent system outages and voltage collapse. While the Working Group did not attempt to reach a consensus for a specific transmission option, the Working Group members agree that transmission relief is necessary.

ISO-NE tested two transmission loops, one with the 345 kV loop proposal and one with the two 115 kV option, under a variety of conditions. ISO-NE found that the Phase I 345 kV Bethel-Norwalk line and the two 115 kV option improve electric reliability in SWCT. Completing the loop with a 345 kV Phase II line further improves reliability in the near term. As load grows, the 345 kV solution avoids more problems and is ISO-NE's recommended solution. CL&P and ISO-NE believe that the two 115 kV circuits would become overstressed by the time the twin circuits go into service. The Five Towns believe that the two 115 kV option is the preferred solution and that the overstressed conclusion is not supported by the data.

WORKING GROUP AND TASK FORCE RECOMMENDATIONS

The Working Group and the Task Force acknowledge the distinct and critical needs of environmental quality and energy adequacy in Connecticut and what is necessary to achieve both goals at the same time. Achieving environmental and energy goals requires the participation of all stakeholders in the development of a common energy policy, instead of competing policies. Implementing the twin goals of adequate and affordable energy and environmental protection requires changes to the existing regulatory process. This report's recommendations are intended to encourage alternatives to transmission infrastructure projects, to allow more meaningful public participation, to improve flexibility in reviewing similar projects, and to expand consideration of environmental resources.

To these ends, the Working Group and Task Force offer the following recommendations:

1. A Connecticut Energy Coordinating Authority (CECA) should be established. The CECA would provide planning, coordination, and public review for energy and associated environmental issues among state agencies, and represent Connecticut's coordinated energy policy and needs before ISO-NE (or successor entities) in the regional planning process.

2. Through a public hearing and review process, the CECA should establish the environmental values and preference standards to be utilized in the CECA's concurrent comparative review of competing projects and solutions.

3. The Working Group and Task Force concur with and reiterate the recommendations of the 2002 Legislative Program Review: "The Connecticut Energy Advisory Board (CEAB) should do an analysis of what would be the appropriate state entity to have responsibility for oversight of state energy policy." In accordance with CEAB's analysis, the appropriate agency should prepare a State Energy Plan that assesses the state's energy resources, summarizes forecasts of loads and capacity, articulates the state's energy policy, and formulates long-range energy planning objectives and strategies. The State Energy Plan should reflect consideration of the cumulative impacts on Connecticut's environment and natural resources reasonably likely to take

place with the implementation of the energy strategies incorporated in the State Energy Plan.

The Working Group also offers the following recommendations:

4. The CECA should commission a Transmission Options Manual, to be updated periodically, that describes the safety, engineering, and reliability parameters for overhead and underground transmission line design.

5. Through the public hearing and review process, the Siting Council should review and, where appropriate, revise the Application Siting Guide for Electric and Fuel Transmission Line Facilities to assure that it incorporates the information that the Siting Council will need to conduct a diligent and sufficient environmental project-specific review.

6. The life-cycle cost analyses for underground versus overhead lines that are performed every five years by the Siting Council per CGS Sec. 16-50r, to date, have been limited to 115 kV transmission lines. To assist in the evaluation of the full financial impact of transmission reinforcements and expansions, future studies should include 345 kV transmission lines.

7. ISO-NE should adhere to a standard protocol for developing, modeling, and implementing transmission studies under the auspices of the Transmission Expansion Advisory Committee (TEAC).

8. The DPUC should evaluate the benefits and legal authority of utility ownership of DG and of generation as a reliability asset, as well as define the limitations for such ownership. Utility ownership of such reliability units should be discussed with a different group of stakeholders, including generators and regulators, in order to address market competition.

9. DG pilot programs should be developed in targeted areas, with DPUC oversight and a suitable mechanism for cost recovery that can demonstrate potential cost-effective applications to avoid or complement transmission upgrade or expansion projects.

10. The DPUC should continue to follow, and actively participate as necessary, in the current FERC investigation[1] on interconnection standards for small and large generators.

11. The DPUC should expand the scope of the natural gas Local Distribution Companies' (LDCs) current energy efficiency programs under the Energy Efficiency Collaborative Group (EECG). Using dollars already allocated to efficiency programs, the LDCs should apportion a dollar amount not to exceed their current funding levels

[1] FERC Docket RM02-12

for efficiency programs, subject to review and adjustment by the EECG and by the DPUC.

ACKNOWLEDGEMENTS

The ISE, the Working Group, and the Task Force would like to thank each of the technical specialists who came before the collaborative sessions and provided valuable expertise and insights: Commissioner Donald W. Downes, DPUC; Commissioner Arthur J. Rocque, Jr., DEP; Joel M. Rinebold, Executive Director, ISE; Tom Kiley, New England Gas Association; Craig Kazin, ISO-NE; Betsey Wingfield, DEP; John Volk, Department of Agriculture; John Curtis, Department of Agriculture; Mike Ludwig, National Marine Fisheries Service; Milan Bull, Connecticut Audubon; Rich Jacobson, DEP; Senator Donald Williams; Rep. Jessie Stratton; Richard Blumenthal, Attorney General; Mary Healey, Consumer Counsel; Harold W. Borden, PSEG Power; Chris James, DEP; Joel Gordes, Solar Design Service; Dan Sosland, Environment Northeast; Charlotte Pyle, PhD., Natural Resources Conservation Service; David Small, Massachusetts Metropolitan District Commission; Dr. Mark Mitchell, Connecticut Environmental Justice Coalition; Cynthia Jennings, Attorney at Law; David Brown, ScD., Environment & Human Health Inc.; Cindy Jacobs, DPUC; Rich Kowalski, ISO–NE; Richard Soderman, CL&P; Bruce Blakey, CL&P; S. Derek Phelps, Connecticut Siting Council; Randy Mathura, FERC; Eric Johnson, ISO-NE; Walter Zenger, Electric Power Research Institute; John Engelhardt, USI; Greg Sullivan, NStar; John Miller, TransEnergie; Mike McCarthy, American Superconductor; Ed Gonzales, Duke Energy Company; Dave Warman, Iroquois Gas Transmission System; Roger Zaklukiewicz, CL&P; Michael Smalec, Southern Connecticut Gas; John Troccioli, UTC Fuel Cells; Jim Watts, Ingersoll-Rand; Janet Besser, Lexecon; John Mutchler, CL&P; Joseph Hebert, United Illuminating; Devang Patel, NXEGEN; Dave Ljungquist, NXEGEN; David Simpson, DEP Fisheries; Mark Johnson, DEP Fisheries; Dr. Frank Bohlen, University of Connecticut; Scott Miller, FERC; Robert Carberry, CL&P; Robert Jontos, Land-Tech Consultants; Robert Duke, The Surety Association of America; David Schlissel, Synapse Energy Economics; Paul Peterson, Synapse Energy Economics Inc.; Susan Tierney, Lexecon; Paul DeCotis, New York State Energy Research and Development Authority; Thomas Kirk, Wisvest; David Damer, Wisvest; Gabriel Stern, Connecticut Municipal Electrical Energy Cooperative; Dr. Gary Ginsberg, Department of Public Health; Dr. Ellen Cool, LAI; Mark DeCaprio, DEP; Marika Tatsutani, Northeast States for Coordinated Air Use Management (NESCAUM); David Blatt, DEP; Ralph Lewis, State Geologist; Edward Gonzales, Duke Energy; Joseph Reinemann, Islander East; Dr. Mathew Cordaro, Long Island University; Thomas Michelman, Xenergy; Larry Williams; Robert Granfield; John Plunkett, Optimal Energy, Inc.; Robert Forrester, Woodland Coalition; Dr. Richard Stein, Committee for Responsible Energy; Joe Wyzik, El Paso; Patricia Sesto, Connecticut Fund for the Environment (CFE); Joseph Petrowski, Five Town Representative; and Larry Rossi, Five Town Representative.

The ISE, the Working Group, and the Task Force would like to thank everyone for their assistance including, but not limited to, the staff at the Department of Public Utility Control, Department of Environmental Protection, and the Legislative Office Building.

The Institute for Sustainable Energy at Eastern Connecticut State University is funded and supported by The Connecticut Conservation and Load Management Fund through the Energy Conservation Management Board, and The Connecticut Clean Energy Fund.

1 INTRODUCTION

1.1 REGULATORY FRAMEWORK

Governor John Rowland's Executive Order No. 26 issued April 12, 2002 and PA 02-95 signed into law on June 3, 2002 raise critical questions about current energy planning and management, including the necessity and benefits of transmission projects, technology alternatives to transmission expansion, and the individual and cumulative effects of proposed crossings within Long Island Sound. PA 02-95 established a Working Group and a Task Force to examine these matters and to assist with the preparation of a comprehensive assessment and report.

The Working Group's mission stems from concerns regarding CL&P's application before the Siting Council to construct a 345 kV transmission line from Bethel to Norwalk. PA 02-95 defers final decision on this application until February 1, 2003, after the Working Group completes its assessment. Under Section 2 of PA 02-95, the Working Group is specifically charged with evaluating:

(A) **The economic considerations and environmental preferences and appropriateness of installing such transmission lines underground or overhead;**

(B) **the feasibility of meeting all or part of the electric power needs of the region through distributive generation; and**

(C) **the electric reliability, operational and safety concerns of the region's transmission system and the technical and economic feasibility of addressing these concerns with currently available transmission system equipment.**

In addition, the Working Group must also "include recommendations for any legislative changes deemed necessary as a result of such assessment."

The Task Force is focused on the protection of Long Island Sound, one of the largest marine estuaries on the east coast of the U.S. In the months leading up to passage of PA 02-95, a considerable number of proposals for both electric transmission cables and natural gas pipelines crossing Long Island Sound were placed before the Siting Council and the DEP. PA 02-95 placed a one year moratorium preventing any state agency from considering or rendering a final decision on any application relating to electric, gas, or telecommunications crossings of Long Island Sound, other than a project involving replacing the existing electric transmission cables in the Norwalk, Connecticut to Northport, New York corridor, and other than relating solely to the maintenance, repair or replacement necessary for repair of electrical power lines, gas pipelines, or telecommunications facilities that currently serve islands or peninsulas off the Connecticut coast or harbors, embayments, tidal rivers, streams or creeks. The Task

Force is charged by statute to obtain information on the current status of electric, gas and telecommunications lines crossing or within Long Island Sound, evaluate the documented and the potential environmental impacts of such lines, and assess the contribution of such lines to the reliability and operation of the state's and the region's energy and telecommunications infrastructure. Section 3 of PA 02-95 sets forth eight specific matters to be addressed by the Task Force:

(A) … a comprehensive inventory and mapping of all existing environmental data on the natural resources of Long Island Sound, including, but not limited to: All coastal resources, as defined in section 22a-93 of the general statutes, all points of public access and public use, locations of rare and endangered species including the breeding and nesting areas for such rare and endangered species, locations of historically productive fishing grounds and locations of unusual and important submerged vegetation;

(B) an evaluation of the relative importance and uniqueness of the natural resources and an identification of the most ecologically sensitive natural resources of Long Island Sound;

(C) an assessment of the present status, future potential and environmental impacts on Long Island Sound of meeting the region's energy needs that do not require the laying of a power line or cable within Long Island Sound;

(D) an evaluation of methods to minimize the numbers and impacts of electric power line crossings, gas pipeline crossings and telecommunications crossings within Long Island Sound, including an evaluation of the individual and cumulative impacts of any such proposed crossings;

(E) an inventory of current crossings of Long Island Sound and an evaluation of the current environmental status of those areas that have crossings;

(F) an evaluation of the reliability and operational impacts to the state and region of proposed crossings of Long Island Sound and an evaluation of the impact on reliability by recommended limitations on such crossings;

(G) recommendations for providing for regional energy needs while protecting Long Island Sound to the maximum extent possible; and

(H) **recommendations on natural resource performance bond levels to insure and reimburse the state in the event that future electric power line crossings, gas pipeline crossings or telecommunications crossings substantially damage the public trust in the natural resources of Long Island Sound.**

The Governor's and the legislature's actions are timely. FERC and ISO-NE are advancing proposals to standardize the regional wholesale electric market and implement new wholesale market rules that will affect Connecticut, especially SWCT, a growing region with one of the most serious transmission constraints in New England. Energy infrastructure is no longer a state-specific issue, but a regional one, in which each state must balance the related issues of energy costs, reliability, conservation, environmental protection, and fairness.

1.2 WORKING GROUP AND TASK FORCE PARTICIPANTS

Commencing in July 2002, the Working Group and the Task Force convened on a regular basis in a series of collaborative meetings organized by the ISE. PA 02-95 named the ISE as the Chair for the Working Group and the Task Force. The member organizations of the Working Group and Task Force are prescribed by the Executive Order and PA 02-95 and are identified in Table 1 and Table 2, respectively.

Table 1 – Working Group on the Bethel-Norwalk Transmission Line

Organization	Participating representative
Institute for Sustainable Energy	Joel M. Rinebold, Executive Director (*Chair)*
The Five Towns (Bethel, Redding, Weston, Wilton, Norwalk)	Larry Rossi Joseph Petrowski Paul F. Hannah, Jr., First Selectman, Town of Wilton (alternate)
Connecticut Fund for the Environment	Patricia Sesto
Connecticut Light & Power	Roger Zaklukiewicz, Vice President – Transmission Richard Soderman, Director - Regulatory Planning Robert Carberry, Project Manager-Transmission (alternate) Paula Taupier, Manager of Transmission Regulatory Planning (alternate)
ISO - NE	Craig Kazin, Senior External Affairs Representative

Table 2 – Task Force Concerning the Protection of Long Island Sound

Organization	Participating representative
Institute for Sustainable Energy	Joel M. Rinebold, Executive Director (*Chair)*
Department of Public Utility Control	Cindy Jacobs, Principal Financial Specialist
Department of Environmental Protection	Betsey C. Wingfield, Assistant Director, Office of Long Island Sound Programs
Connecticut Siting Council	Philip Ashton
Office of Policy and Management	Marc Ryan
ISO-NE	Eric Johnson, External Affairs Representative
Federal Energy Regulatory Commission	Randy Mathura
DEP Bureau of Fisheries	Rick Jacobson
Agriculture Department, Bureau of Aquaculture	John Volk, Director
Department of Transportation, Coastline Port Authority, Bureau of Aviation and Ports	Alan Stevens
Connecticut Seafood Council	Barbara Gordon
Long Island Soundkeeper	James Murkette
Save the Sound, Inc.	Leah Lopez, Staff Attorney
Connecticut Fund for the Environment	Penny Anthopolos, Staff Attorney Jerry Shaw
Connecticut Geological and Natural History Survey	Ralph Lewis, State Geologist
TransEnergie US	Rita L. Bowlby, Vice President Connecticut Government Affairs
SBC/SNET	Gregory J. Zupkus, Director, External Affairs
Connecticut Natural Gas and Southern Connecticut Gas	Tim Kelley Mike Smalec
Yankee Gas Company	Patricia McCullough, Director of Environmental Management, Northeast Utilities System
Connecticut Light and Power	Elizabeth Barton (Day Berry & Howard) Harold Blinderman (Day, Berry & Howard, alternate)
United Illuminating Company	Michael Coretto
Atlantic States Marine Fisheries	Ernest Beckwith
Representative from an applicant for a gas pipeline[2]	

[2] PA 02-98 states that the Task Force shall include one representative from an applicant for a gas pipeline. Iroquois and the Islander East Pipeline Company, both applicants for the cross-Sound pipeline projects, were unable to come to agreement on a representative to be the single Task Force member. Both Iroquois and Islander East representatives monitored Task Force meetings and made technical presentations.

The Working Group and Task Force members called upon the resources of diverse technical specialists who delivered valuable presentations at the collaborative sessions. A list of all technical presenters is included in Appendix F. The ISE engaged LAI to support the Working Group and Task Force by providing technical information regarding the region's energy infrastructure and environmental resources. LAI was also charged with facilitating some of the collaborative meetings and preparing this report. Meeting agendas, minutes, presentation materials, and other documents utilized by the Working Group and Task Force have been collated under DPUC Docket 02-04-23.[3]

1.3 Comprehensive Assessment and Report – Part I and Part II

This document is intended to comply with the legislative mandate for the Working Group to develop by January 1, 2003, a comprehensive assessment and report (the Assessment Report) that addresses each element of PA 02-95 Section 2. The required elements of the Assessment Report and recommendations charged to the Task Force by Section 3 have significant overlap with the Working Group's mission. The Working Group and Task Force objectives are interrelated – both must address energy reliability within the integrated New England electric grid and gas pipeline network. The energy infrastructure and environmental resources are not bounded by the shoreline of Connecticut or the political boundaries of the state.

The Working Group and the Task Force were able to jointly develop convergent recommendations that are presented and supported in this Comprehensive Assessment and Report – Part I. Central to this work, the Working Group and Task Force jointly present a framework intended to facilitate the comparison of alternative energy strategies and competing solutions, that appropriately balances the need for cost-effective and reliable energy resources with Connecticut's commitment to protect its environmental resources. This Comprehensive Assessment and Report – Part I also presents recommendations to improve state energy planning in the deregulated electric and gas markets.

The Task Force intends to prepare a separate Comprehensive Assessment and Report – Part II to fully consider all of the issues associated with the natural resources of Long Island Sound. This effort, assigned to the Task Force under PA 02-95 Section 3, must rely on a vast assemblage of environmental data from diverse sources that is still being evaluated. It is expected that the Comprehensive Assessment and Report – Part II will be completed and presented to the Governor and General Assembly by June 3, 2003.

In a parallel effort, the ISE has commissioned Xenergy to conduct an energy audit of Norwalk. That report will discuss potential demand-side resource and DG options, as well as the barriers and other issues surrounding the implementation of demand-side options.

[3] This can be viewed at http://www.state.ct.us/dpuc/database.htm.

In developing this Comprehensive Assessment and Report, the Working Group and Task Force have relied upon extensive information provided by the technical specialists who came before the members during the collaborative sessions. Section 2 of this report presents a comprehensive summary of this background information, augmented by additional relevant material, which provided the foundation for the Working Group and Task Force's analysis of the issues. Section 2 also contains information that specifically addresses PA 02-95 Section 2 elements, as indicated in Table 3.

Table 3 – P.A. 02-95 Section 2 Requirements

	Relevant Sections in this Report
(A) The economic considerations and environmental preferences of installing transmission lines underground or overhead	2.9, 3, 4.3
(B) the feasibility of meeting all or part of the electric power needs of the region through distributive generation	2.1, 2.2, 2.3, 2.12, 3, 4.4
(C) the electric reliability, operational and safety concerns of the region's transmission system and the technical and economic feasibility of addressing these concerns with currently available transmission system equipment.	2.2, 2.3, 2.9, 2.11, 3, 4.3

Section 3 of this report presents the conclusions of the Working Group, and Section 4 of this Assessment Report summarizes the key issues and offers a salient recommendation for each issue.

2 SUMMARY OF BACKGROUND INFORMATION

2.1 OVERVIEW OF THE COMPETITIVE ENERGY MARKET

2.1.1 Historical Background

Over the last two decades, airlines, trucks, banks and telecommunications have been deregulated. Industry experts generally agree that competition has brought significant economic benefits and cost savings to segments of these restructured industries, while at the same time creating new challenges for industries, regulators, and consumers. The natural gas and electricity industries were the most recent American monopolies to transition to competitive market forces. Deregulation of Connecticut's natural gas and electricity industries has been well underway since the late 1980s when a series of orders issued by FERC effectively deregulated interstate pipeline transportation across the U.S. By 1992, FERC completed the transition to competition under Order No. 636, which required pipeline transportation and storage services to be available to all shippers on an unbundled, non-discriminatory basis. At the local level, natural gas transportation and distribution services continue to be regulated by state regulatory commissions throughout New England.

Following FERC's success introducing competition in the natural gas industry, Congress passed the Energy Policy Act of 1992 to stimulate a workably competitive market for wholesale electricity. New England's bulk generation and transmission facilities had been operated by NEPOOL, a voluntary association of investor-owned and municipal utilities throughout New England, since 1971. NEPOOL had achieved significant cost savings and reliability improvements for its members. In 1996, FERC issued Order 888 to remove impediments to competition in the bulk power marketplace in order to lower costs for consumers. FERC required all utilities that owned transmission assets to implement tariffs available to all eligible users (including themselves), to assure non-discriminatory, open-access transmission policies, and to separate transmission services from power marketing functions. These actions were considered to be central to the success of the competitive wholesale power market.

Also in 1996, FERC issued Order 889, which contained rules establishing and governing an Open Access Same-time Information System (OASIS), and prescribing standards of conduct. Under Order 889, each public utility (or its agent) that owns, controls, or operates facilities used for the transmission of electricity (generally above 69 kV) is required to create or participate in an OASIS that describes available transmission capacity, prices, and other information that will enable transmission customers to obtain open access non-discriminatory transmission service.

In response, NEPOOL proposed that an independent system operator (ISO) be created to administer the deregulated wholesale power markets for NEPOOL membership. In July 1997, ISO-NE was created in large part through the transfer of staff and equipment from NEPOOL. ISO-NE assumed the planning and management of New England's transmission system from NEPOOL, and the additional responsibility for administering the wholesale electricity market when the market opened for competition in May 1999. Whereas NEPOOL dispatched generation across New England to minimize the total variable cost of producing electricity from hour to hour based on actual operating costs, under the new market structure ISO-NE schedules generation to minimize costs based on market bids to serve electricity demand. The higher costs of running generation out-of-merit-order to address specific reliability concerns in load pockets have been socialized since May 1999 across NEPOOL participants. Upon establishment of a congestion management system in accord with FERC standards, the socialization of out-of-merit-order costs to remedy specific reliability concerns in load pockets will end or be phased out.

By the end of the 1990s, nearly all investor-owned electric utilities in New England had completed the divestiture of their non-nuclear power plants. More recently New England utilities have completed the sale of their nuclear power plants as well. Utilities were also permitted stranded cost recovery by which the costs of uneconomic assets and contracts could be recovered through surcharges to retail rates. Generation costs are now determined by the market and, with few exceptions, are not subject to cost regulation. Other electric utility services continue to be regulated under cost of service principles. State regulatory commissions have jurisdiction over in-state activities and retail electric rates. FERC retains jurisdiction over wholesale power markets and the transmission of electricity. In July 2002, FERC issued a NOPR to create a SMD, a single nationwide set of standard market rules.[4] In December 2002, FERC issued an order approving New England's implementation of SMD in March 2003. With SMD, FERC intends to eliminate remaining barriers to wholesale electric competition within and between power pools and control areas, have power prices established on a locational basis, and provide a level playing field for all participants.

2.1.2 Electric Restructuring in Connecticut

In 1998 Connecticut joined other states in restructuring its electric industry. The Act Concerning Electric Restructuring, PA 98-28, authorized competition in electric generation services starting in 2000. This law effectively required Connecticut's investor-owned electric utilities to divest generating assets while requiring them to provide standard offer service through the end of 2003 for retail customers who do not choose an alternative service provider. The law established a beneficial rate for standard offer service in relation to the baseline cost of electric service, that is, standard offer rates effective January 1, 2000 were to be at least 10% less than the applicable 1996 bundled retail rates. PA 98-28 contains extensive environmental, consumer education, and consumer protection provisions, as well as findings that constitute additional energy policy goals for the state's electric sector. PA 98-28 established key objectives for Connecticut's restructured electric industry:

[4] Docket No. RM01-12-000, issued July 31, 2002, also referred to as the "Giga NOPR".

- Support the safe, secure and reliable operation of Connecticut's energy infrastructure;
- Lower energy costs and stimulate sustainable economic and job growth through technological innovation and market forces;
- Increase energy diversity, efficiency, and customer choices; and
- Preserve public policy measures such as conservation and renewable resources.

At the same time, PA 98-28 recognized a number of difficulties and tradeoffs:

- Promoting generation competition while retaining a regulated distribution system and maintaining fairness, equity, and ratepayer protections;
- Balancing costs, risks, and rewards for electric utilities and customers as the industry continues its transition; and
- Encouraging generation development while protecting public health and the environment.

With the availability of natural gas for power generation and the exit of New England's utilities from the generation business, the region has witnessed a building boom of new generation plants. In contrast, other regions in the U.S. have not been as fortunate, including New York. In New England, over 10,500 MW of advanced, gas-fired generating plants have been or are soon to be added to the regional electricity grid, roughly 40% of the most recent peak electricity demand across the region. While approximately 3,160 MW of new generating resources have received Siting Council approval in Connecticut, not all of this capacity is certain to be placed in service.[5] Areas of potential energy shortfalls in parts of New England have evolved into areas of energy abundance, at least in the near term, due to massive investment in new power plants and, to a lesser extent, new gas pipelines linking New England with Atlantic Canada. The hallmark of a competitive market, however, is the allocation of energy resources to the users who value them highest. New England's abundance is not experienced uniformly across the region. SWCT continues to experience threats to bulk power reliability as a result of robust demand, limited and older generation within the region, and less than adequate, reliable transmission capacity.

Pipelines, too, have substantially increased pipeline delivery capacity into and within New England. Potentially abundant new natural gas supplies off the coast of Nova Scotia in Atlantic Canada constitute an important new energy source for New England, thereby

[5] Bridgeport (nameplate capacity 520 MW), Killingly (792 MW), and Wallingford (250 MW) are on line. Milford (544 MW) is under construction and nearly complete but has not yet filed an operations plan due to litigation. Meriden (525 MW) construction has stopped; the project is near bankruptcy, but has received an extension from the Siting Council. Oxford (520 MW) has not yet started construction due to litigation.

lessening the region's critical reliance on both residual fuel oil and traditional natural gas supplies from the Gulf Coast and western Canada. Connecticut enjoys both economic and reliability benefits through more flexible transportation delivery arrangements by existing wholesale transporters as well as heightened natural gas competition across rival gas producing basins. Other initiatives promoting the development of renewable energy sources, management and conservation of energy demand, and more protective air emissions regulations are part of the comprehensive overhaul of the energy industry.

Connecticut finds itself at the crossroads where gas pipelines and electric transmission lines are competing for market share in New York State, especially Long Island. Insofar as dynamic regulatory and market forces promote the integration of energy infrastructure across control area boundaries, Connecticut is swept into the debate over how best to meet energy objectives in SWCT as well as on Long Island. More than ever before, Connecticut is challenged to protect the state's natural resources, including Long Island Sound. Hence, Connecticut is today faced with complex policy issues associated with achieving the delicate balance between economic growth and the environmental preservation objectives associated with high voltage transmission lines and interstate pipelines to neighboring regions.

2.1.3 Energy Deregulation and Environmental Protection

Meeting the energy needs of the citizens of Connecticut and the region must be balanced with protecting Connecticut's natural resources. Historically, this balance has been achieved through the interplay of utility regulation combined with strong environmental protection laws wherein regulators balanced need or benefit against environmental protection. Integrated Resource Planning (IRP) was a formalized process to evaluate the full range of supply and demand-side options with considerable public input and state agency scrutiny. Under utility deregulation pursuant to PA 98-28, the competitive marketplace determines which energy supply facilities are proposed rather than a public policy-driven energy planning process emphasizing long term least cost analysis and environmental management. Connecticut has taken a leadership role in strengthening air regulations that apply to the operation of electric generation. Connecticut has implemented clean air regulations that will significantly reduce sulfur dioxide and nitrogen oxide emissions from Connecticut's power plants, including older, less efficient plants in SWCT.[6] These regulations are among the strictest in the nation. Connecticut is also one of several states that has enacted a Renewable Portfolio Standard (RPS), requiring licensed electricity suppliers in Connecticut to include an annually increasing percentage of renewable energy as part of its generation portfolio.

However, with respect to the siting of energy facilities, including transmission lines, the existing environmental review process was not necessarily designed to address the

[6] These plants, many of which contain multiple units, burn oil and coal. The units were the subject of Public Act 02-64, An Act Concerning Reducing Sulfur Dioxide Emissions at Power Plants and include Norwalk, Bridgeport, New Haven, Middletown, Montville, and Devon. Bridgeport and Devon are in SWCT.

cumulative impacts of competitive infrastructure project in a deregulated market. Although the Siting Council is required to consider cumulative environmental impacts that may result from a proposed project, the Siting Council, the DEP, and other state and federal agencies review each new proposed project based on each project's individual merits. However, it is not within their specific authority to contemplate comparative environmental analysis of competing alternative projects, including conservation initiatives or one or more infrastructure projects that may be proposed in a similar time frame to address the same energy needs. Moreover, some projects are submitted in phases over time, further limiting regulating entities and the public from fully evaluating the potential adverse impacts of the entire project. Thus, the current environmental review framework could better facilitate the assessment of cumulative impact and does not have a mechanism to gauge adequately the relative merits of competing projects.

2.2 Electric Transmission Infrastructure in Connecticut and the Region

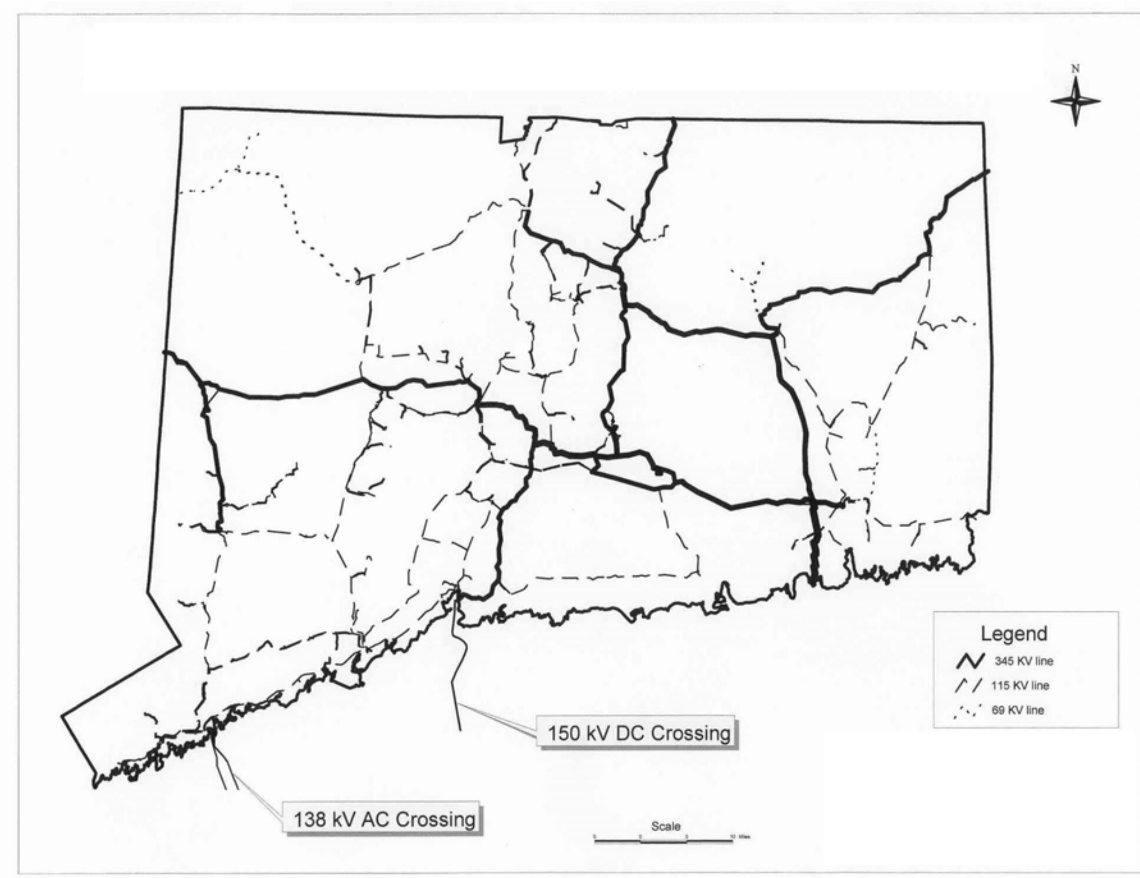
During the 1960s utility interest in large, centralized nuclear power and fossil power plants warranted sharing ownership and cost responsibilities.[7] Through the 1960s and 1970s, New England's utilities jointly planned and individually constructed a 345 kV high voltage alternating current (HVAC) transmission system to transmit generation output from these pool-planned units over long distances to the major load centers. Because there were eleven power plants whose output was shared by New England's utilities, the 345 kV system was referred to as the "Big 11 Powerloop." The 345 kV voltage level was selected based on reliability and security objectives, including the ability to connect directly with the New York grid. The resulting 345 kV system is the backbone of the region's bulk transmission network. Lower voltage transmission lines, predominantly at the 115 kV level, interconnect smaller generators while transmitting power supply to other cities and towns throughout New England.

At the time, the 345 kV system was a significant achievement. In 1975 Northeast Utilities (NU) noted, "Today about 35 percent of the power generated in New England on a typical day is transmitted from generating stations over the 345 kV network. Load centers throughout much of southern New England benefit directly from this 345 kV supply system, with one notable exception, the southwest area of Connecticut which is not yet supplied by the 345 kV network."[8]

The New England high voltage transmission grid consists of over 8,225 miles of power lines rated 115 kV and above.[9] The grid's 345 kV backbone runs through coastal Maine and New Hampshire, around Boston to Cape Cod, and through central Connecticut. There is also a 450 kV High Voltage Direct Current (HVDC) line from Quebec to

[7] Examples include New Boston, Connecticut Yankee, Bridgeport Harbor, Merrimack, Canal, Brayton Point, Millstone, Vermont Yankee, Pilgrim, Northfield Mountain, and Maine Yankee.
[8] Northeast Utilities, "Ten-Year Forecast of Loads and Resources 1975-1984."
[9] There is a small amount of 69 kV transmission line.

Figure 1 – Connecticut Electric Transmission Map[10]



northeastern Massachusetts that delivers large amounts of hydropower into New England from Hydro-Quebec. In-state, CL&P, an NU subsidiary, owns 1,688 circuit miles of transmission lines, and UI owns 119 circuit miles of transmission lines as shown in Table 4.

Table 4 – New England and Connecticut Electric Transmission Lines (miles)

Voltage Ratings	New England	CL&P	UI
HVDC line	192	0	0
345 kV	1,758	392.3	6.1
230 kV	444	0	0
69, 115 & 138 kV	5,831	1,295.4	113.0
Total	8,225	1,687.7	119.1

[10] Source: ISE, based on data submitted by CL&P to the Siting Council.

Most of New England's high voltage transmission lines are Pool Transmission Facilities (PTF) providing regional transmission and reliability services. The costs of PTF assets are recovered by transmission owners through regional network service transmission rates approved by FERC. In 1996 NEPOOL filed a comprehensive proposal at FERC to restructure the NEPOOL Agreement.[11] NEPOOL's proposal was addressed by FERC in various orders, the first of which was issued in June 1997. As part of the restructured NEPOOL Agreement, socialization of congestion costs, that is, cost recovery spread throughout New England to all NEPOOL participants on the basis of each participant's load share, was approved by FERC for an interim period. The interim period ends with implementation of a congestion management system. Non-PTF transmission assets, such as radial lines connecting generators to the grid or connecting the grid to small load centers, are recovered through generator payments of construction costs and local network service tariffs approved by FERC.

Interties – New England has a number of transmission interties with neighboring systems. A 345 kV line from New Brunswick provides a transfer capability of about 700 MW. Quebec has three asynchronous connections with New England. The largest is the Hydro-Quebec HVDC line to the Sandy Pond substation in Massachusetts; this HVDC line has a rated capacity of 2,000 MW. In part, because of concerns outside of NEPOOL's control area, it represents the largest contingency in New England and is typically limited to about 1,200 to 1,700 MW. Moreover, the operation of the Hydro-Quebec transmission line could also create potentially unacceptable overloads in the New York or PJM control areas.

There are a number of transmission lines interconnecting New York and New England. Connections from Connecticut include a 345 kV line from the Long Mountain switching station located in New Milford, the 138 kV submarine line (No. 1385) from Norwalk Harbor to Northport, Long Island, and TransEnergie's new Cross Sound Cable (TE-CSC) from New Haven to Brookhaven, Long Island. The net transfer capability of the New York-New England interconnections ranges from 700 to 1,000 MW depending on seasonal ratings and the distribution of load and generation in the two adjoining control areas.

Merchant Transmission Lines – A new class of transmission lines that are not regulated utility assets has developed in the U.S. over the past few years. TE-CSC, installed in 2002 but not yet fully operational, is the first merchant transmission line in the U.S. Because its fixed and variable costs are recovered through the sale of transmission rights, merchant transmission lines are similar to merchant generators in that costs are not automatically recovered through a regulated utility rate-base mechanism. Capital and operating costs are at risk. Virtually all such proposed lines are HVDC lines with converter station controls that permit power flows to be controlled by the applicable system operator. This technology allows the owner to identify the transmission benefits that the line provides, thereby establishing the economic basis for the investment. In contrast to HVDC lines, investment in the existing alternating current (AC) transmission system does not normally allow "contract flows" to be identified separately from physical

[11] Docket No. OA97-237-000.

flows. It is thus impractical for investors in new AC transmission line projects to receive the benefits that the line provides; AC transmission line projects are not well suited for merchant at-risk investments.

2.2.1 Transmission Planning Process

The Northeast Blackout of 1965 highlighted the need to assure regional reliability among the interconnected utilities. As a result, coordination arrangements among the utilities in New England became more formalized. NEPOOL was officially formed in 1971 to establish a single regional network to direct the operations of the major generating and transmission facilities in the region, *i.e.*, the bulk power system. During this period, electric utilities conducted comprehensive supply-side and demand-side planning subject to state regulatory oversight. Utilities developed detailed cost and performance estimates for a full range of options, from conventional power plants and the associated transmission lines, to C&LM programs for all customer classes. The options were evaluated on a revenue requirements basis, *i.e.*, the net cost to ratepayers. Externalities, from environmental impacts to fuel diversity benefits, were explicitly considered. By the 1980s the IRP process formally encompassed input from public advocacy groups and was subject to detailed state commission scrutiny before programs or construction projects were approved.

Today, the reliability of the bulk electric system continues to be the responsibility and a top priority of ISO-NE. Since utilities have divested their generating assets, traditional IRP is no longer possible because the obligation to provide capacity to ensure reliability has, by statute and regulation, been relegated to the marketplace. In response to the fundamental electric industry changes in the region, NEPOOL approved and ISO-NE instituted a formal process to assess the reliability and economics of the transmission system and to plan for transmission improvements and expansions, and to provide a reliability "backstop" if market responses to identified issues prove inadequate. ISO-NE commenced the FERC-required RTEP process following the Amended and Restated NEPOOL Agreement in September 2000.[12] ISO-NE prepared the second plan, the 2001 Regional Transmission Expansion Plan (RTEP01) in collaboration with other stakeholders including state regulators. In addition to assessing New England's transmission needs, the RTEP process is intended:

> to provide a "request for solutions" that serves as the market signals appropriate for the planning of generation, Merchant Transmission Facilities, Elective Upgrades, Demand Side Management (DSM) and Load Response Programs (LRP). To the extent that the market signals provided by the RTEP process fail to result in the market responding with adequate solutions for system problems or needs, the RTEP develops a coordinated transmission plan that identifies appropriate projects for ensuring a reliable electric system and for reducing congestion in an economic manner.[13]

[12] 66th Agreement amending the Restated NEPOOL Agreement.
[13] RTEP02, p. 2, 11/07/2002.

An update of the Regional Transmission Expansion Plan (RTEP02) was issued in draft form by ISO-NE in September 2002 and was approved by ISO-NE's Board of Directors on November 8, 2002.

2.2.2 Transmission Expansion Advisory Committee

The RTEP reports (1) incorporate comprehensive technical studies of the ability of generation and transmission to meet load responsibilities reliably and economically, and (2) identify potential transmission solutions in New England. These studies are conducted under the purview of TEAC, the prime source of stakeholder input to the RTEP process. Formed in 2002, TEAC provides NEPOOL members, regulators, marketers, consumer advocates, and other stakeholders a method to interact with ISO-NE for the assessment of system reliability and transmission projects. TEAC participants discuss reliability problems and address the impact of proposed transmission projects on load flows, security of supply, and bulk power system reliability. Subject to a nominal participation fee, TEAC meetings are open to the public. TEAC does not approve RTEP findings; that responsibility resides with the ISO-NE Board. Nor does TEAC approve transmission projects; NEPOOL and ISO-NE consider the project's interconnection to the transmission system and NEPOOL approves cost recovery, but each state's individual siting authority or utility commission evaluates the necessity and merits of the project.

2.3 ELECTRIC RELIABILITY IN CONNECTICUT AND THE REGION

2.3.1 Reliability Criteria

ISO-NE plans and operates the New England bulk power system to criteria that address both adequacy of generating resources to meet projected demand, and that comply with transmission planning/operating criteria set forth in NEPOOL's Planning Procedures. ISO-NE's transmission plan is based on the reliability criterion that the bulk power system should not fail to meet load more than once every 10 years.[14] This criterion is probabilistically calculated as a Loss of Load Expectation (LOLE) by simulating the operation of the bulk power system, reflecting scheduled maintenance and unscheduled (or forced) outages of both generation and transmission assets, as well as unusual customer demands. The one event in 10 year LOLE criterion is one used by bulk power planners elsewhere in the U.S. and Canada. Distribution system failures are not considered in the LOLE calculation. Central to this reliability simulation are contingency events where critical resources are assumed to fail or be unavailable. ISO-NE plans for such events by having a robust system capable of withstanding severe and sudden changes with sufficient generation and transmission redundancy. These stochastic inputs include:

[14] This criterion refers to the bulk power system, comprised of generation and transmission assets, and does not include utility distribution systems.

- weather and load variations,
- generator outages and seasonal adjustments,
- transmission line and equipment failures and seasonal adjustments, and
- contingencies on other systems interconnected with ISO-NE.

A failure to meet LOLE criteria suggests a major system reliability issue. At the same time, satisfying the criteria alone does not guarantee a reliable system. There may be transmission problems within RTEP sub-areas that are not revealed by this particular analysis. This is why there is a need to satisfy both generation and transmission criteria before a system can be considered "reliable."

To allocate responsibility for meeting this reliability criterion, the LOLE is converted to an "Objective Capability" value for each month of the Power Year (June through May), subject to monthly adjustments for changing system conditions.[15] In this context the reliability criterion is sometimes characterized as an installed capacity margin requirement. For example, New England's Objective Capability was 28,263 MW for July 2002 and 28,241 MW for August 2002. These values correspond to a 16.8% and 16.7% margin above the forecast load of 24,200 MW, respectively.

Expressing system reserves[16] in terms of MW or as a percentage of load sometimes obscures the fact that protection against loss of load must be provided by backup transmission as well as by backup generating capacity. To assure reliability, the ISO-NE transmission system plans sufficient transmission capability that can "take up the slack" in the event of a generation or transmission-related contingency event. Some of these lines may be consistently in a state of reserve and not loaded to capacity. However, the transmission system must be designed to maintain the current and voltages levels within the operating limits of each of the system components during normal operation as well as during a contingency event. In addition, the New England bulk power system must "remain stable during and following the most severe of the contingencies."[17]

2.3.2 Historical Demand

The reliability of the electric system in Connecticut and New England depends on a number of related factors, including customer demand, generation capacity, and, transmission infrastructure. Peak electric demand has grown significantly in the last two years due to demographic and economic growth, as well as unusually hot weather during the summers of 2001 and 2002. The resulting peak demand data through 2001, provided in Table 5, is taken from CL&P's response to data request CSC-01, Q-CSC-005 filed on

[15] Restated NEPOOL Agreement, Section 7.5(e) and Section 12.
[16] Supply in excess of peak demand.
[17] Reliability Standards for the New England Power Pool, July 9, 1999.

December 14, 2001 in Docket No. 217. Connecticut includes SWCT, and SWCT includes NOR. Peak demand data for 2002 was provided by ISO-NE.

Table 5 – Historical Peak Demand (MW)

Year	NEPOOL[18]	Connecticut	SWCT	Norwalk-Stamford
1997	20,569	6,019	2,858	1,043
1998	21,406	5,836	2.777	1,029
1999	22,544	6,345	3,125	1,142
2000	21,736	5,900	2,841	1,018
2001	24,967	6,799	3,247	1,188
2002	25,348	6,825	3,285	1,208

2.3.3 Demand Forecast

The most recent ISO-NE forecast of peak demand is contained in the *2002 Capacity Energy Load and Transmission* (CELT) *Report,* issued April 1, 2002.[19] As shown in Figure 2, assuming normal summer weather patterns, New England's peak demand is expected to grow by 1.6% annually to 27,860 MW by 2011.[20] Protracted heat and humidity in the summer of 2002 resulted in a record peak of 25,348 MW, significantly above the forecast value of 24,200 MW. The fact that actual peak demands can exceed normal weather forecast values must be taken into account when conducting planning studies. Peak demand in the SWCT area is not forecast separately by ISO-NE, but is estimated as a percentage of total New England peak demand.

After reviewing forecasts of peak demand in Connecticut and SWCT from 2002 forward that had been prepared by ISO-NE and Connecticut's electric distribution companies, the DPUC announced its own estimate "that the peak demand in SWCT will range between 3,000 MW and 3,500 MW in 2002 and will grow at approximately 1.75% thereafter."[21] July 3, 2002, the day the DPUC published this conclusion, was the 2002 peak load day for SWCT. The load experienced was 3,285 MW, approximately the 3,300 MW that the DPUC used for its "reference case" in the Summer Shortage Report.[22]

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[18] Demand data from CELT Reports, 1997-2002.

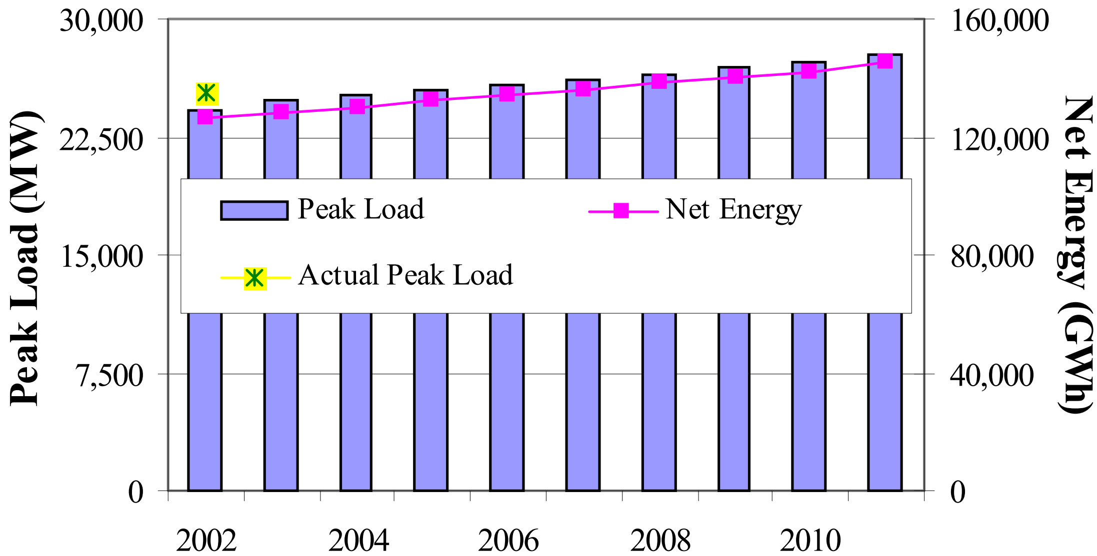
[19] Peak load (also referred to as demand or peak demand) is typically measured in MW and is a key factor in transmission and generation reliability. Load or energy consumption is typically measured in MWh and is not a key reliability factor.

[20] NEPOOL peak load forecast takes into account DSM, customer self-generation, weather normalization, and other adjustments.

[21] DPUC Docket No. 02-04-12 – DPUC Investigation into Possible Shortages of Electricity in Southwest Connecticut During Summer Periods of Peak Demand (July 3, 2002) (Summer Shortage Report), p. 8.

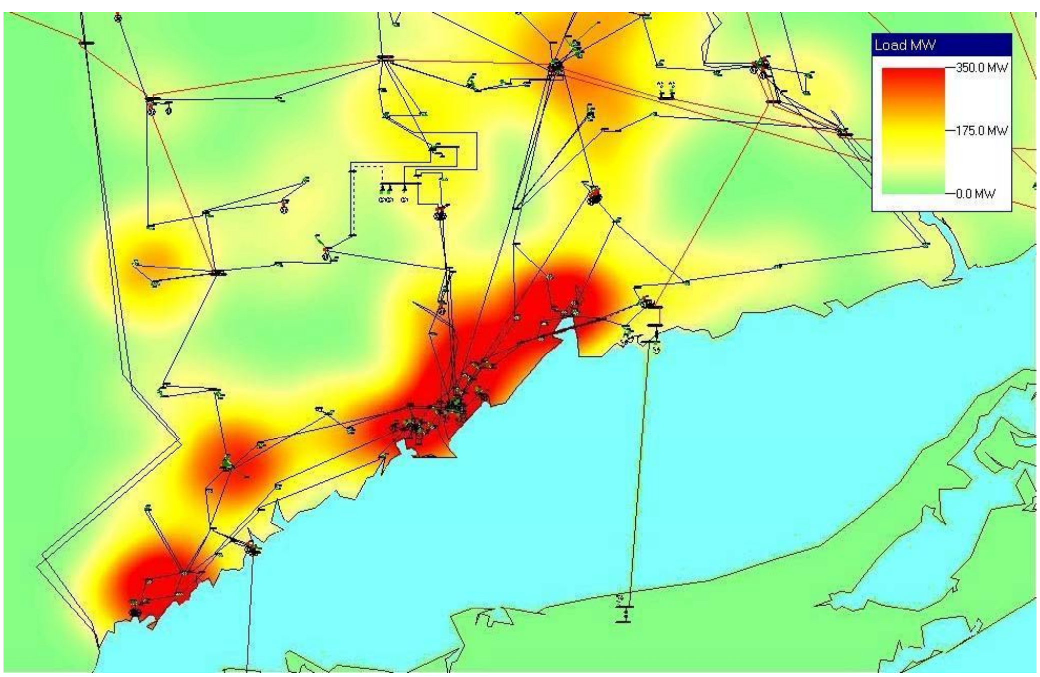
[22] Summer Shortage Report, p. 3.

Figure 2 – ISO-NE Forecast of Annual Energy Consumption and Peak Load[23]



The map in Figure 3, taken from the TEAC 13 presentation (Appendix G), graphically illustrates the load densities in SWCT. Heavy electric loads are concentrated around Stamford, Norwalk, and the corridor between Bridgeport and New Haven.

Figure 3 – Load Densities – Southwestern Connecticut

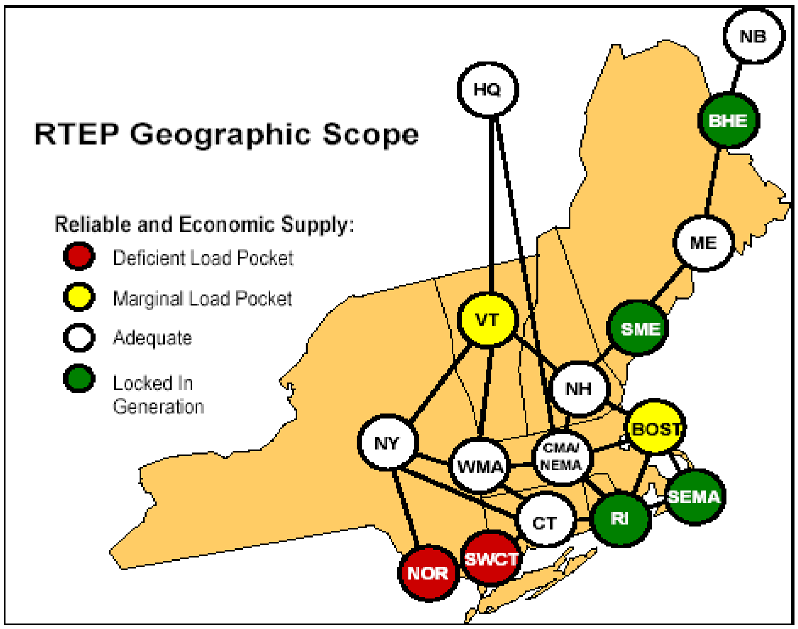


[23] Weather normalized.

2.3.4 Electric Reliability and Congestion

Figure 4 is reproduced from the RTEP02 Report, and shows the primary transmission sub-regions and locations of insufficient transmission capacity.

Figure 4 – Regional Assessment of Transmission Capability



The 13 RTEP sub-areas and 3 external areas shown in Figure 4 are designated as follows:

- BHE - Bangor Hydro Electric
- ME - Maine
- S-ME - Southern Maine
- NH - New Hampshire
- VT - Vermont
- BOSTON - Boston Import
- CMA-NEMA - Central Massachusetts / Northeastern Massachusetts
- W-MA - Western Massachusetts
- SEMA - Southeastern Massachusetts
- RI - Rhode Island
- CT - Connecticut
- SWCT - Southwestern Connecticut
- NOR - Norwalk / Stamford
- NB - New Brunswick
- HQ - Hydro-Quebec
- NY - New York

Load pockets (congested areas) are regions or sub-regions that are dependent upon transmission capacity to import power to serve their demand. Deficient load pockets require the operation of more expensive local generation (also referred to as out-of-merit) to meet peak load requirements because less expensive generation outside the load pocket cannot be transported to serve local load. The additional costs to run these generators in a load pocket out-of-merit order are paid by customers in the form of congestion charges called "uplift." Under current NEPOOL regulations, uplift charges are socialized among all customers in New England. If the transmission constraints are severe enough and peak loads cannot be met via transmission imports and local generation capability, voltage disruptions and power outages may ensue.

SWCT, including the NOR sub-area, is designated as a Deficient Load Pocket and is of particular concern to ISO-NE and FERC given the severity of the transmission constraint, the amount of load potentially at risk, and the siting complexities associated with expanding the transmission system to ensure grid security. Locked-in Generation Regions are areas where insufficient transmission capacity prevents economic generation from being transmitted out of the sub-area at certain times, thereby requiring more expensive generating plants located outside the Locked-in Generation area to run. When lower cost generating plants are displaced by higher cost generation out of the Locked-In Generation area, wholesale energy clearing prices may increase. Presently, these higher prices are borne by customers both in Locked-In Generation area as well as outside the Locked-In Generation area by virtue of the socialization of uplift costs.

Under recent FERC guidelines promoting SMD, the emphasis on location based price signals is designed to elicit market responses which shift the incremental cost of energy to the load associated with transmission congestion. FERC's proposed Locational Marginal Pricing (LMP) set forth under SMD will allow the energy clearing prices in load pockets to increase to the marginal price of the most expensive local generator dispatched to serve local load. The energy clearing prices in Locked-in Generator areas will decrease to the lowest bid price of the generator that must operate due to transmission constraints. Hence, the energy clearing price signals will result in a market response encouraging new generation or transmission where it would be most cost effective.

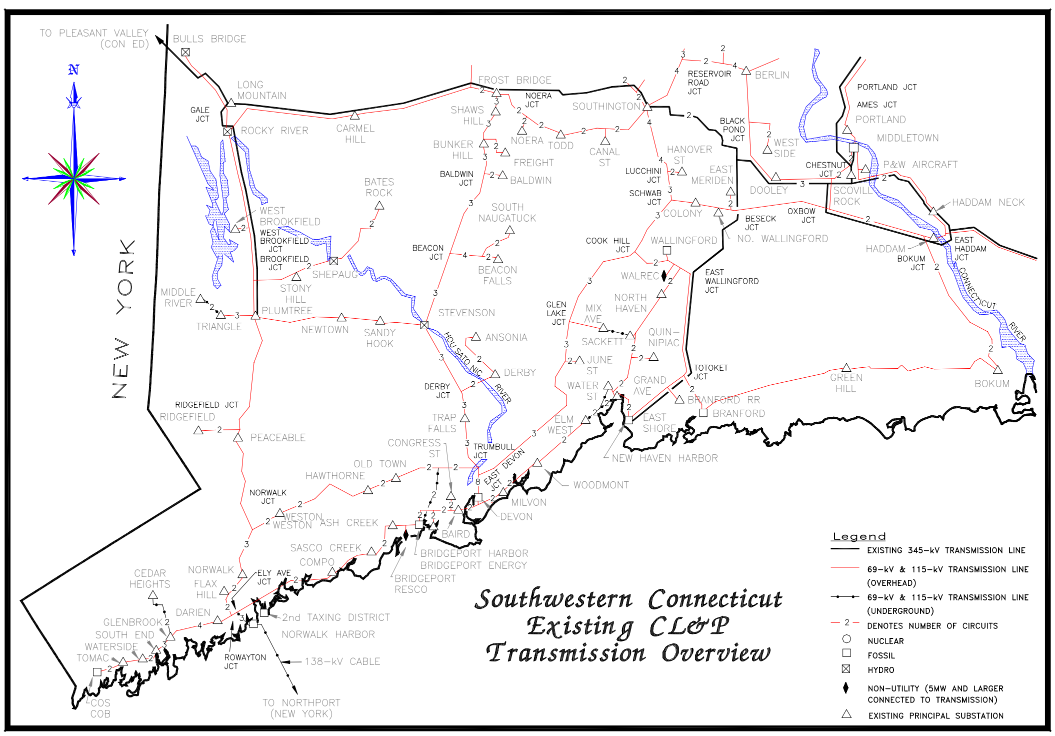
Geographically, SWCT is defined as the 52 municipalities within the southwest quadrant of the state, extending as far north as New Milford, east to Meriden, and south to Branford. In RTEP, the NOR sub-area (13 towns and cities) is separate from SWCT (39 cities and towns).[24] Electrically, SWCT is defined as the area served by four 115 kV busses in Bethel, Watertown, Southington, and New Haven (Figure 5). The 115 kV transmission lines feeding the SWCT load pocket, arranged by electrical bus, include:

[24] Refer to the Glossary for a listing of all municipalities in SWCT and NOR.

Table 6 – SWCT and NOR Electric Transmission Interfaces

Southwest Connecticut	Frost Bridge - Carmel 115 kV (1238)
	Frost Bridge - Shaws Hill 115 kV (1445)
	Frost Bridge - Freight 115 kV (1721)
	Frost Bridge - Baldwin Tap 115 kV (1990)
	Southington - Glen Lake 115 kV (1610)
	Southington - Lucchini 115 kV (1690)
	Southington - Wallingford 115 kV (1208)
	Green Hill - Branford 115 kV (1508)
	East Shore – Branford RR 115 kV (1460)
	East Shore – Grand Avenue 115 kV (8100)
	East Shore – Grand Avenue 115 kV (8200)
	Plumtree 345 - 115 kV #1 XF (1X)
	Plumtree 345 - 115 kV #2 XF (2X)
Norwalk / Stamford	Plumtree - Ridgefield Jct. 115 kV (1565)
	Trumbull Jct. - Old Town 115 kV (1710)
	Trumbull Jct. - Weston 115 kV (1730)
	Pequonnock - RESCO Tap 115 kV (91001)
	Pequonnock - Compo 115 kV (1130)

Figure 5 – Electric Map of SWCT[25]



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25 CL&P Application for a Certificate of Environmental Compatibility and Public Need for an Electric Transmission Line Between Plumtree Substation in Bethel and Norwalk Substation in Norwalk, 10/15/2001, Figure 14.

SWCT Generation – The plants that are electrically within SWCT are listed in Table 7, along with their summer ratings and fuel type, according to the RTEP02 Report. The most recent addition is Wallingford 1-5, five gas turbines designed to provide peaking power with fast response times.

In May 2002, NRG, the owner of the Devon units, requested ISO-NE approval to deactivate Units 7, 8, and 10. Units 7 and 8 are gas / oil-fired thermal units and Unit 10 is a jet-fueled combustion turbine that provides black-start capability for the Devon station. ISO-NE conducted a study in accordance with Section 18.4 of the NEPOOL Agreement to determine whether the deactivation would have a significant adverse effect on NEPOOL system reliability. In August, ISO-NE and NRG finalized an agreement by which Units 7 and 8 would remain available through September 2003 or until they are no longer needed. A key factor is the commercial operating date of Milford Power 1 and 2, a new 536 MW gas-fired combined cycle plant that is located within SWCT, near the Devon Station. The RTEP02 Report assumed it would be in service in the summer of 2002, but it has not yet entered commercial operation and may not be available for the summer 2003 due to litigation. Although studies show that the addition of Milford allows the deactivation of Devon 7 and 8, SWCT would still be short on supply, because of problems moving power both into and within SWCT and NOR.

Table 7 – Existing Power Plants in SWCT

Name and Unit Number	Demonstrated Capacity (MW by unit)	Fuel
Branford 10	16.2	oil
Bridgeport Harbor 2, 3, 4	152.0, 370.4, 12.4	oil, coal, gas
Bridgeport RESCO	59.5	refuse
Bridgeport Energy	447.9	gas
Cos Cob 10, 11, 12	15.5, 15.5, 16.1	oil
Derby Dam	7.1	hydro
Devon 7, 8, 11, 12, 13, 14	107.0, 106.8, 30.9, 30.9, 31.0, 30.8	gas / oil
Norwalk Harbor 1, 2, 10 (3)	162.0, 168.0, 11.5	oil
Shepaug	41.7	hydro
Stevenson	28.3	hydro
Rocky River	29.4	hydro
Wallingford 1-5	212.0	gas
Wallingford Refuse	6.43	refuse
Total	2,109.3 MW	

Two power plants in SWCT have special contracts to assure reliability in the area, Devon 7 and 8. In November 2002, negotiations commenced with other units for special contracts. It should be noted that New Haven Harbor is not electrically within SWCT.[26]

[26] RTEP02 Appendix 13.5

There is currently no plan to reconfigure the system to tie that station into a new bus within the load pocket, primarily because it would not relieve problems within SWCT.

RTEP 2001 focused particular attention on SWCT and NOR, and contained the following primary conclusions:

- SWCT, particularly the NOR sub-area, will have severe reliability problems beginning in 2004 if the largest single generation source in the area, the Milford combined cycle plant, is unavailable.
- Even with Milford available, SWCT and especially the NOR sub-area will have reliability problems in later years if other generation (Bridgeport Energy and Bridgeport Harbor) or other transmission resources become unavailable.
- Significant transmission congestion occurs between Maine (locked-in generation in Maine) and Boston (load pocket), SEMA-RI (locked-in generation) and Boston. Congestion in Boston and SWCT costs ratepayers between $125-$600 million annually.[27] Almost two-thirds of this cost was due to congestion in SWCT and the NOR sub-area.[28]

The main recommendation in RTEP01 was "to pursue, on a priority basis, short-term transmission system upgrades to address the SWCT reliability concerns." In consideration of SWCT's "marginal" 115 kV system, it also raised the question of whether that system meets NEPOOL and Northeast Power Coordinating Council operating or planning criteria.

In response to RTEP01, ISO-NE issued a Request for Proposal (RFP) in early 2002 for supplemental emergency capacity to be located within SWCT, preferably within the 13 towns located in the NOR sub-area. One of the winning bidders was Berkshire Power Development Inc., which installed three trailer-mounted 23 MW ultra-low sulfur oil-fired turbine generator units in Stamford for the 2002 summer period, June 1 to September 30. CL&P received DPUC approval to construct a short (less than 0.2 mile) 115 kV line to connect these units, referred to as the Waterside Power Project, to the Waterside substation. The Waterside Power Project received capacity payments for the summer period, but was not called upon to operate. It is possible that ISO-NE will issue a similar RFP for the summer of 2003.

The RTEP02 Report provided a status report on the RTEP01 recommendations and updated the RTEP01 findings. The most urgent system reliability need identified in RTEP02 was in SWCT and NOR. "Without widespread transmission infrastructure upgrades, studies demonstrate widespread violations of transmission planning criteria. As a result, without such upgrades, it is doubtful that the existing system could reliably support projected loads in the long term. ISO-NE has determined that the existing

[27] It was expected that the Boston load pocket would be mitigated by new transmission and generation projects into and within the Boston sub-area.
[28] Refer to RTEP01 Tables 5.1.10c and 5.1.10e.

transmission system configuration cannot provide for significant generation expansion or even the simultaneous operation of existing generation at full load." Other findings were as follows:

- Short-term transmission upgrades (upgraded breakers, installed capacitor banks, reconductored lines), as well as emergency and load response measures, improved reliability in SWCT for the summer 2002.

- ISO-NE found that the most effective long-term strategy to reduce congestion costs was to improve import limits, *i.e*., extend a 345 kV loop from Plumtree into NOR (Phase I) and to Beseck Junction (Phase II).

- Projected congestion costs in New England under an SMD environment will be mostly due to constraints in SWCT and NOR, and could range from $50-$300 million in 2003.[29]

In its Summer Shortage Report, the DPUC identified reliability deficiencies in the SWCT electric supply system, primarily with reference to the potential for electricity shortages during the summers of 2002 and 2003. The DPUC concluded that, by virtue of targeted conservation programs, strengthened LRPs, and near term improvements to the local transmission and distribution system, electricity shortages during those summers could probably be avoided.[30] The DPUC cautioned, however, that

> Inadequate local generation and transmission congestion in SWCT make the region vulnerable to reliability problems in the event that demands are higher than expected or any of the generation units or transmission lines servicing the area are unavailable, particularly during peak periods. The outlook for the summer of 2004 is much less positive. The retirement of Norwalk Harbor and Cos Cob generation units would create an electric shortage in the Norwalk-Stamford area if this continues as planned and additional generation can not be added in the region.[31]

Significant findings of the DPUC in the Summer Shortage Report bearing on long term solutions to the SWCT reliability problems included:

- SWCT is generation-deficient.

- Transmission of power to SWCT is constrained by an inadequate transmission system.

- Movement of power within the region is also constrained by internal constraints.

[29] Forecasted New England congestion costs were lower than in RTEP01, due to transmission improvements and generation projects into and within the Boston load pocket.
[30] Summer Shortage Report, pp. 1, 33.
[31] Summer Shortage Report, p. 33.

- There constraints "hinder the ability of ISO-NE to move power into and around the region, or add additional generation to increase supply."

- New capacity additions to the area are further constrained by the limits of the circuit breaker capacity.

- Because of the limitations of the transmission, all of the existing generation within the area can not be run at the same time.

- Congestion costs associated with these transmission constraints may create significant economic consequences to all Connecticut customers.

2.3.5 Transmission Rates and Cost Allocation

FERC has jurisdiction over interstate commerce, including operation of the wholesale market and the establishment of transmission rates. Under the FERC-approved Open Access Transmission Tariff in effect since 1997, the NEPOOL tariff provides for four kinds of transmission service:

- Through or Out Service covering transmission transactions going out of or through New England,

- Regional Network Service (RNS) covering transmission services other than Through or Out Service,

- Internal Point-to-Point Service covering an identified delivery and receipt point within New England, and

- Merchant Transmission Facilities.

NEPOOL has had a tradition of socializing the cost of transmission improvements through the RNS tariff or, prior to 1997, the Pool Transmission Rate. In some cases specific transmission project expenditures were borne by individual transmission companies. Under the RNS tariff, transmission services are priced under a postage stamp rate among all transmission customers in New England. The resultant transmission revenues are allocated to the transmission owners in accordance with the FERC cost-of-service cost recovery principles. To the extent congestion is experienced within New England requiring ISO-NE to operate certain power plants out-of-merit order, the cost of uplift is currently socialized across all New England transmission system load.

Since the NEPOOL Agreement was amended in 1997, costs for new PTF not attributed to generator interconnections have been shared regionally on a per-kW basis. Under the existing mechanism, NEPOOL has distinguished between PTF and non-PTF until LMP is put in effect, planned for March 2003. In response to an intervention filed by the Maine

Public Utilities Commission and the Vermont Department of Public Service,[32] FERC expressed concern about the NEPOOL's socialization of transmission system upgrade and expansion costs as well as congestion costs once NEPOOL implements LMP. In July 2002, FERC required ISO-NE and/or NEPOOL to propose a revised default cost allocation methodology in ISO-NE's SMD filing "consistent with an LMP scheme." ISO-NE's general SMD plan was accepted by FERC on September 20, 2002.

Separating network reliability from congestion reduction costs, and the eventual allocation those costs is a key issue for Connecticut ratepayers, market participants, and regulators. In the fourth quarter 2002, ISO-NE commenced a series of workshops with industry stakeholders throughout New England in order to define a standardized approach to allocate transmission investment cost recovery to transmission customers throughout New England. In the workshops, stakeholders across New England are exploring how to formulate a procedure to distinguish between regional reliability benefits and local service benefits when investments are incurred by transmission owners for PTF, non-PTF, or other network facilities. ISO-NE's inquiry into the alternative methods to apportion transmission costs among benefited parties is raising contentious issues associated with the merits of rival fairness and efficiency criteria. While NEPOOL's historic practice of socializing PTF expenditures is under review, NEPOOL and/or ISO-NE are required to "provide an objective, non-discriminatory default cost allocation mechanism that is consistent with the principles of cost causation."[33]

The SMD NOPR[34] proposes guidelines to standardize wholesale electricity pricing. This standardized approach is substantially similar to the LMP scheduled to be implemented in New England in March 2003. The SMD NOPR[35] also proposes a system to allocate scarce transmission rights based on value of service principles. While FERC's SMD may compel the assignment of congestion costs (reflected in higher LMPs) to local areas, these salable transmission rights will provide some degree of hedging against the impacts of higher locational pricing.

On December 20, FERC issued an Order on Rehearing[36] generally accepting ISO-NE's compliance filings on SMD, and establishing rules for the determination of congestion costs. In response to filings made by the DPUC and the Connecticut Attorney General, FERC declined to delay implementing LMPs but agreed to moderate the LMP impact on Connecticut ratepayers. To aid in the transition to LMP, FERC committed to allow the costs of "a defined set of transmission upgrades into Southwest Connecticut" to be spread among customers throughout New England provided that such upgrades are placed in service within five years of the date of the order. According to the December 20 Order,

> This rate treatment will also apply to those upgrades that are already planned or under construction as of the date of this order, such as the transmission

[32] Docket No. ER02-2330-000
[33] 100 FERC, 61,287 at p. 144
[34] Docket No. RM01-12-000
[35] Ibid.
[36] 101 FERC, 61,344

upgrades in ISO-NE's 2002 Transmission Expansion Plan to address problems in Southwest Connecticut, as to which Phase I is planned to be completed in 2004 and Phase II is planned to be completed in 2006.

The FERC Order is silent on the cost allocation issues concerning the incremental costs of underground versus overhead lines.

2.4 NATURAL GAS INFRASTRUCTURE IN CONNECTICUT AND THE REGION

2.4.1 Overview of the Natural Gas Industry

The natural gas supply path from the wellhead to the burner-tip consists of producers, operating wells and gathering systems in the supply regions, interstate or interprovincial pipeline systems that transport gas from the producing basins to the city gates in the market areas, and, lastly, the LDCs that transport natural gas from the city gates to residential, commercial, and industrial customers. Historically, most natural gas used in New England was for space heating, hot water heating, and industrial process uses. More recently, natural gas has become a vital fuel for power generation – nearly all of the new power plants developed in New England since the early 1990s, as well as those currently under construction, use natural gas as their primary fuel partially due to environmental, permitting, and capital cost benefits. The greater power generation efficiency and reduced emissions associated with natural gas are likely to continue to support the trend in New England toward the increased use of gas as a fuel for power generation.

Natural gas provides approximately 20% of the primary energy currently consumed in New England and 16% of the primary energy consumed in Connecticut. The U.S. Department of Energy, Energy Information Administration (EIA) predicts that natural gas use in New England will continue to grow, reaching approximately 26% of the primary energy consumed in the region by 2020. Although no separate forecast is available from the EIA for Connecticut, gas consumption is expected to increase at a rate that exceeds the growth in the region as a whole. According to ISO-NE, natural gas is forecasted to account for over 50% of New England's electricity supply by 2005.[37]

Until the late 1980s the natural gas industry was highly regulated, with every aspect of operations from production at the wellhead through transportation and delivery to the burner tip regulated by federal and state agencies. FERC Order Nos. 436, 500, and 636 in 1985, 1987, and 1992, respectively, unbundled the interstate natural gas transportation and storage functions. The Natural Gas Wellhead Decontrol Act of 1989 completed the deregulation of the natural gas commodity that commenced in 1978 when Congress first removed wellhead price controls under the Natural Gas Policy Act. FERC has jurisdiction over the transportation and storage of natural gas in interstate commerce, the sale of natural gas in interstate commerce for resale, and the companies engaged in these

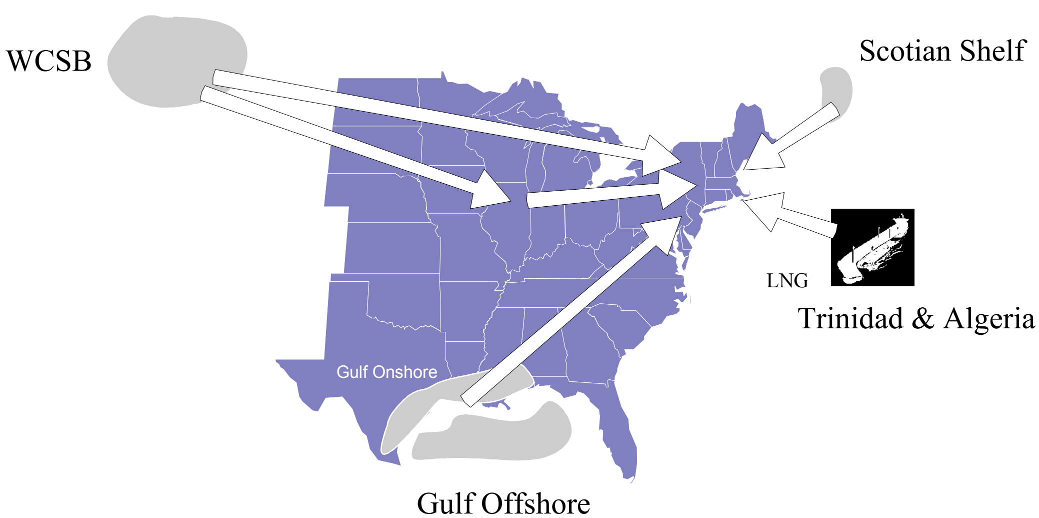
[37] ISO-NE, Steady State and Transient Flow Analysis of New England's Interstate Pipeline Delivery Capability, 2001-2005, prepared by LAI, February 2002.

activities. These tariffs governing the service terms and conditions associated with interstate transportation and storage services are still regulated by FERC under the Natural Gas Act. Beginning in 1992 when FERC issued Order No. 636, pipelines have exited the traditional "merchant" function associated with the procurement of natural gas. All transportation service is offered to shippers on an open access, non-discriminatory basis. Interstate pipelines must receive a Certificate of Public Convenience and Necessity from FERC before a pipeline can be expanded or extended. The U.S. Department of Transportation (DOT) is responsible for the establishment and enforcement of safety on interstate pipelines. The regulation of LDC retail gas sales and the provision of local delivery services remains the responsibility of state public utility commissions.

2.4.2 New England's Gas Supply

Most of the natural gas consumed in New England is derived from supply basins in Canada or the U.S. Gulf Coast. Clearly, Connecticut has no indigenous gas supplies, so it must rely on the production of gas and transmission of gas by other states and countries. Comparatively small amounts of gas are produced from fields in Appalachia, the Mid-Continent, and the Rocky Mountains (Figure 6). Fields in the Gulf Coast and western Canada accounted for 74% of the gas supplied to meet U.S. demands in 2001. New England's reliance on these two supply sources is higher, more than 80%. Delivery to end users in Connecticut from gas wells in western Canada involves transmission through more than 2,000 miles of inter-provincial and interstate pipelines, whereas natural gas from the Gulf Coast is about 1,500 miles away. In 2000, New England's dependence on western Canada and the Gulf Coast potentially lessened with the introduction of gas produced from the Scotian Shelf near Sable Island off the coast of Nova Scotia. Sable Island is by far New England's closest supply region, only 750 miles from New England.

Figure 6 – Natural Gas Supply Sources for New England



Prior to receiving natural gas from Sable Island, being at the "end-of-the-pipe" meant that New England was more exposed to supply interruptions resulting from operating contingencies, accidents or extreme weather conditions along the entire pipeline path, particularly when pressures fell in response to extreme and persistent cold. New England's LDCs have managed this exposure through the use of storage along the interstate pipelines, especially in Pennsylvania and New York, and, to a lesser extent, in the Gulf of Mexico and in Dawn, Ontario. To provide needle-peaking service during extreme cold, New England's LDCs have maintained above-ground liquefied natural gas (LNG) storage facilities, capable of storing large amounts of supplemental gas supplies behind the citygate, as well as smaller amounts of propane that can be mixed with air and utilized.

Connecticut's LDCs use LNG throughout the winter in order to supplement pipeline rendered supplies. Vaporization of LNG instantaneously bolsters both pressure and flow across the distribution network when extreme cold or other operating contingencies occur. While most LNG stored by LDCs in New England is transported via truck from Everett, Massachusetts, some utilities in New England manufacture LNG as well. Liquid propane gas is also stored by some LDCs behind the citygate and can provide additional protection against possible constraints on the redelivery of LNG during adverse weather conditions.

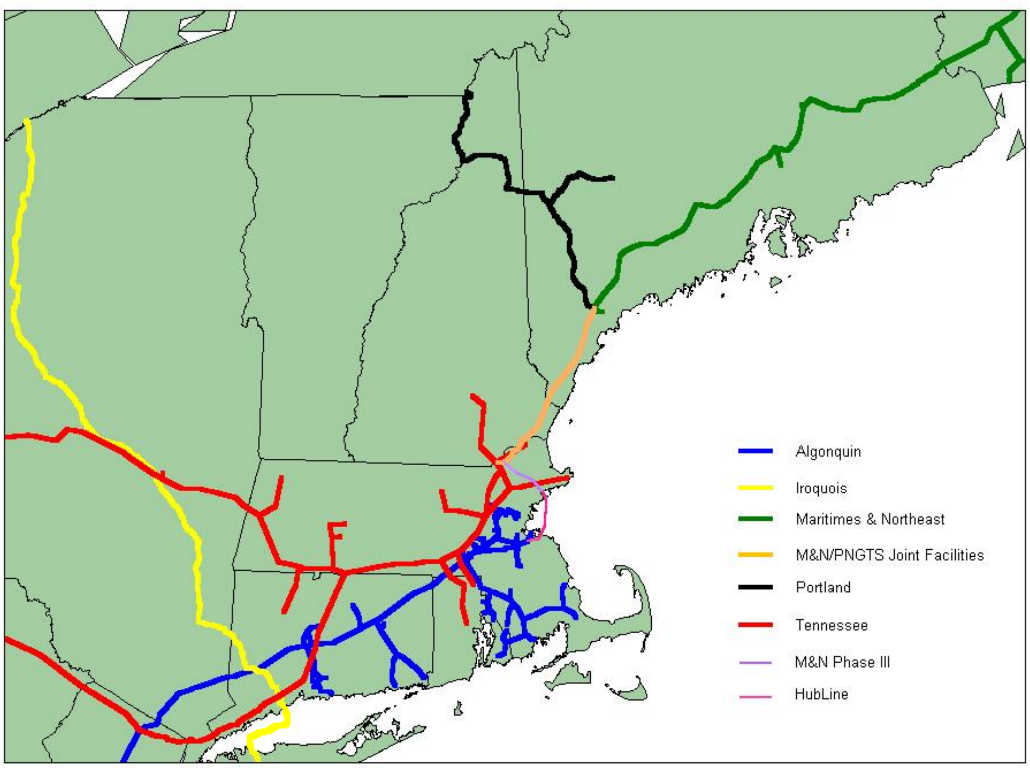
New England's LNG is imported by Distrigas, a subsidiary of Tractebel, a Belgian energy company. Most LNG destined to New England is produced in Trinidad, a comparatively new liquefaction terminal located about 2,300 miles from Boston. In addition to Trinidad, shipments also originate from Algeria and occasionally other LNG export points around the world. LNG is natural gas chilled to -260^{o} F so that it forms a liquid that requires only $1/600^{th}$ of the volume that natural gas vapor requires, thus making tanker transport economically feasible. Distrigas imports LNG using specially designed tankers through Boston Harbor to its terminal in Everett, Massachusetts, where most LNG is re-vaporized and injected into pipeline or LDC interconnections for transport across New England or local use, and some LNG is trucked to other storage facilities in New England.

Gas supplies sourced out of the Gulf Coast move to the markets in New England through Transcontinental Gas Pipe Line (Transco), Tennessee Gas Pipeline Co. (Tennessee), Columbia Gas Transmission Corp. (Columbia), Texas Eastern Transmission Corp. (Texas Eastern), and Algonquin Gas Transmission Co. (Algonquin). Figure 7 shows the interstate pipelines that serve Eastern New York and New England. The primary conduit for gas from western Canada is TransCanada Pipelines Ltd. (TCPL), which serves the major market centers in Ontario, Quebec, and the export markets. TCPL is the primary high-pressure transportation route linking western Canada with New England and New York. The Iroquois Gas Transmission System (Iroquois) delivers gas from TCPL at the U.S. border near Waddington, New York to markets in New England, New York, including Long Island, and New Jersey. The Maritimes & Northeast Pipeline (M&N) and the Portland Natural Gas Transmission System (PNGTS) deliver gas from producing wells on the Scotian Shelf to markets in the Canadian Maritimes and New England.

Iroquois' pipeline began commercial operations in January 1992, the first new significant interstate pipeline in New England in several decades. Iroquois includes a 26-mile submarine segment across Long Island Sound from Milford to Northport, Long Island. About 24% of Iroquois' deliverability is destined for New York across Long Island Sound and another 4% for New Jersey, via a direct connection with the New York Facilities System that allows gas to be delivered on Long Island and New York City. Iroquois provides gas to New England via Algonquin and Tennessee, as well as approximately 200 MMcf/d to LDCs and power producers in southern Connecticut. Connecticut receives 33.6% of the gas transported by Iroquois. Iroquois is currently constructing the Eastchester Extension, a new 24-inch submarine pipeline lateral from Northport, Long Island to the South Bronx solely through New York waters. Iroquois' Eastchester Extension is expected to be in service in 2003.

Tennessee transports natural gas from the Gulf Coast and Western Canada to New York and New England. One leg of the Tennessee system connects with TCPL near Niagara Falls, New York to receive gas from western Canada into New York and New England, while another leg connects with M&N at Dracut, Massachusetts, thereby providing the pipeline with access to natural gas from Atlantic Canada. Another Tennessee leg enters

Figure 7 – Interstate Pipelines Serving New England and New York[38]



[38] LAI, January 2001. *Steady-State Analysis of New England's Interstate Pipeline Delivery Capability, 2001-2005*. Prepared for ISO-NE.

SWCT from New York and ties into the main system near Agawam, Massachusetts. Texas Eastern brings gas from the Gulf Coast to the interconnection with Algonquin at Hanover, New Jersey, for redelivery through New York into New England. Texas Eastern and Algonquin are both subsidiaries of Duke Energy. Both Tennessee and Texas Eastern are also directly tied to the large underground storage fields in New York and Pennsylvania. These storage centers also serve a critical role in providing gas to meet the winter season delivery requirements of New England's gas utilities.

2.4.3 Natural Gas Flow Dynamics into Connecticut and New England

Until 1999, nearly all gas flowing into New England through Tennessee and Algonquin was transported from the Gulf Coast on a "forward-haul" basis using either south-to-north or west-to-east physical flow capabilities. New England's geography had rendered the region at the end of a one-way supply chain extending thousands of miles. In retrospect, there have been comparatively inflexible physical ties to the major producing and storage areas serving New England. Open access transportation under FERC Order No. 636, coupled the commercialization of Iroquois, PNGTS and M&N, fundamentally changing the traditional pipeline flow dynamics within New England. Iroquois, PNGTS and M&N have shortened the "supply chain" linking major producing areas with New England. Now natural gas flows into northern and eastern New England from Atlantic Canada, and into southern and western New England through the traditional pipeline pathways linking the Gulf Coast and western Canada with the market center. These new projects have permitted innovative displacement transactions and deliveries from New England into New York.[39] Gas from the Scotian Shelf can now be delivered via displacement to customers throughout New England and New York.

2.5 TELECOMMUNICATIONS INFRASTRUCTURE IN CONNECTICUT AND REGION

2.5.1 Industry Overview

Today's telecommunications network infrastructure is comprised of optical fiber cable, copper lines, and wireless carriers. These three basic infrastructure technologies provide a wide range of services including local and long distance phone, mobile or cell phone, wireless internet, data and broadband (both television and internet), and paging. Demand for faster and more efficient means of communications has quadrupled in the last ten years.

Initially, the introduction of the telephone service provided easy access by voice, using wires and telephone poles. At the end of World War II, carriers first introduced dialing services and twisted pair copper cable. In the 1970s carriers began to implement digital

[39] Displacement transactions involve delivering equivalent gas volumes from one point on a pipeline to another point without a continuous physical flow between these points. Backhauls are a form of displacement in which gas is delivered to a customer upstream of the point that the customer's gas is actually put into the pipeline.

transmission techniques, which provided faster and better information exchange. Widespread use of computers in business contributed to rapid demand growth. A radio-based microwave system was introduced as an alternative to copper cables, which was especially useful in areas where traditional cable lines were expensive or physically impossible to deploy. In addition, carriers began installing a new optical fiber infrastructure utilizing encoded light signals.

In the 1980s, digital technologies began to replace the voice-grade, analog systems. This was due in large part to the introduction of home computers and the growth of the Internet. Up until this point, the vast majority of improvements were targeted for the long distance and business markets. The residential market, still utilizing twisted pair copper cable technology, could begin receiving both voice and data service utilizing digital encoding to allow simultaneous usage on a single cable pair.

The divestiture of the Bell System in 1983 and the opening of the telecommunications industry to competition invited new non-traditional market entries that persist to this day. Cable television, satellite, and cellular providers now compete in the telecommunications marketplace. Unlike its competitors, however, cellular currently offers two-way interactive service. The cable television industry's current infrastructure uses coaxial cables for one-way distribution. In order to provide two-way cable services, the local cable infrastructure would have to be modified. Satellite system providers face a similar problem as they too now desire interactive service.

2.5.2 Current Telecommunications Technologies

Most of the new systems being installed today are optical fiber-based systems, which utilize two technologies:

- Single-mode fiber is a laser-based technology used most often in the long distance market or the very high bandwidth applications.

- Multi-mode fiber technology utilizes a light-emitting diode and is typically installed on campuses and in households.

The advantage of optical fiber over copper cable is that fiber is not susceptible to electrical interference. In addition, optical fiber signals can travel much further distances than conventional copper based systems without the need for signal regeneration. Today, optical fiber technology transmits virtually the entire range of telecommunications services along the backbone of the data infrastructure network. However, most of the local distribution infrastructure continues to use the older twisted copper cable, coaxial cable, and wireless technology.

Another alternative for long distance transmission is a microwave system, primarily for telephone services. This system transmits radio signals from tower to tower along a path. Microwave systems function on the principle of "Line of Sight," and are highly reliable.

However, it is subject to interference due to atmospheric conditions and is being phased out in favor of optical fiber.

Cellular technology broadcasts interactive analog and digital signals, but propagation is limited due to frequency used, power limitations, and frequency reuse. A few communications devices bounce signals off of satellite technology. For satellite technology, physical infrastructure on the ground is limited to transmitting and receiving equipment, however, the signal may be disrupted under certain atmospheric conditions.

After the initial installation, buried cable (optical fiber or copper) is not visible, requires little maintenance, and is safe from damage when properly installed. Overhead towers and antennas may have aesthetic and visual impacts. Overhead cabling systems require the highest maintenance, but are cost effective in short distance distribution systems. Many municipalities have introduced ordinances that require utilities to bury all new facility installations.

Various overhead and underground construction techniques are utilized depending on the physical conditions. Generally, overhead construction requires the placement of poles and aerial cables along with the related support structure. Because the ROW width requirements are much less than for electric transmission cables, telecommunications lines can typically follow existing public rights-of-way, such as roadways. Underground installations consist of either placing the telecommunications cable within a conduit along an existing public roadway, usually a street or railroad, or directly burying the cable. Crossing of water bodies, major roadways, railroad tracks or other obstacles can be accomplished by Horizontal Directional Drilling (HDD). In the past, cables traversing large water bodies, such as Long Island Sound, were placed on the seabed, where they were prone to damage by nets and anchors. Today, marine installations of telecommunications cables utilize the same burial techniques as for electric cables.

2.5.3 Connecticut's Telecommunications Infrastructure

In 1878, the world's first commercial telephone exchange was opened in New Haven by the Southern New England Telephone Company (SNET). In 1998, SNET merged with SBC Communications Inc, creating a company that serves about one third of the country's telecommunications demand. SBC SNET has a statewide optical cable network infrastructure that covers most of Connecticut, with only a few exceptions. Woodbury Telephone, which is wholly owned by SBC SNET, covers the towns of Southbury, Woodbury and Bethlehem, and Verizon covers a portion of the town of Greenwich. With continuing expansion, by year end 2002, more than 80% of Connecticut homes and businesses will have broadband services available to them through coaxial cable. At the same time, more than 83% will also have Digital Subscriber Line (DSL) service available through the telephone lines. Connecticut also has over 100 independent Competitive Local Exchange Carriers.[40] These firms resell

[40] The list of Competitive Local Exchange Carriers in Connecticut can be found on the DPUC web site: www.DPUC.state.ct.us/DPUCINFO.nsf/ByIntrastate.

SBC SNET services, lease or own local distribution facilities on the SBC SNET network, or in some cases lease or own part of the network. There are also Inter Exchange Carriers and Wireless Carriers that distribute or resell services and have interconnected their facilities with the SBC SNET network.

There are three submarine telecommunications cables in Long Island Sound. The MCI telecommunications cable connects Madison to Rocky Point, Long Island. The AT&T cable connects East Haven to Shoreham, Long Island. The FLAG telecommunications cable is a trans-Atlantic line that runs eastward from Northport, Long Island between Fishers Island and Plum Island, entirely within the waters of New York State.

Due to the multiple interconnections and ring shape of the state's 500,000-mile optical fiber telecommunications network, it achieves full redundancy and a high degree of reliability for consumers. With the fiber optic backbone of the telecommunications network already in place, it is expected that the only telecommunications infrastructure additions that will need to be installed in the next few years will be at the distribution-level, including cellular phone towers and other facilities to support DSL and broadband cable services.

2.6 Protection of Connecticut's Natural Resources

2.6.1 Connecticut Environmental Policies

In 1971, the Connecticut General Assembly adopted the Public Utilities Environmental Standards Act (PUESA, CGS Sec. 16-50g to 16-50aa). Prior to the effective date of this legislation, the DPUC had sole responsibility for reviewing the prudency and siting of utilities' proposals for transmission, generation, and other infrastructure projects. Under PUESA, however, Connecticut articulated its obligation to balance public need and benefit with environmental protection. PUESA delegated siting decisions to an independent body, the Siting Council, prescribed an adjudicatory procedure for project review, and established certification criteria. Over time, PUESA has been revised to include jurisdiction over certain telecommunications facilities, hazardous waste facilities, and electric substations. PUESA remains one of the most comprehensive programs for energy project certification and environmental review in the U.S.[41]

In 1975, the Connecticut legislature adopted ratemaking principles in CGS Sec. 16-19e that require utilities and the DPUC to promote economic development, the development and use of renewable resources, and the prudent management of natural resources. The section was amended in 1979 to require that these actions conform, to greatest extent practicable, to the state's energy policy as contained in CGS Sec. 16a-35k. Three years later, the General Assembly established an explicit state energy policy statement in CGS Sec. 16a-35k that promotes energy conservation, use of renewable sources to the maximum extent feasible, diversification of the state's energy mix, and assistance to

[41] OLR Research Report, "Siting Agencies in Other States"; August 13, 2002; 2002-R-0692.

residents and businesses to reduce energy use and costs. The *Conservation and Development Policies Plan for Connecticut 1998-2003* (the Plan) prepared in accordance with CGS Sec. 16a-24 - 16a-33 is the most recent statement of the state's growth, resource management, and public investment policies. Policy E of the Plan addresses the state's objectives to "[s]ecure a sustainable supply of energy at the best possible cost and promote its efficient use." To achieve this objective, the Plan's policy is to:

- Expedite the review and site approval of needed and environmentally acceptable energy generation and transportation facilities.

- Seek to diversify the state's energy supply mix where practicable with energy resources least vulnerable to interruption and depletion.

- Identify efficiency opportunities in each sector and cost effective improvements.

- Capitalize on opportunities to develop and deploy innovative energy technologies.

Title 22a of the Connecticut General Statutes comprises principal statutes implemented by the DEP. The opening section of this title (22a-1a) declares that:

> it shall…be the policy of the state to improve and coordinate the environmental plans, functions, powers and programs of the state, in cooperation with the federal government, regions, local governments, other public and private organizations and concerned individuals, and to manage the basic resources of air, land and water to the end that the state may fulfill its responsibility as trustee of the environment for the present and future generations.

To carry out the state's environmental policy, the state, through the DEP, is enabled to implement programs as described in section 22a-1a of the Connecticut General Statues so that it may:

- Fulfill the responsibility of each generation as trustee of the environment for succeeding generations;

- Assure for all residents of the state safe, healthful, productive, and esthetically and culturally pleasing surroundings;

- Attain the widest range of beneficial uses of the environment without degradation, risk to health or safety, or other undesirable and unintended consequences;

- Preserve important historic, cultural, and natural aspects of our Connecticut heritage, and maintain, wherever possible, an environment which supports diversity and variety of individual choice;

- Achieve an ecological balance between population and resource use which will permit high standards of living and a wide sharing of life's amenities;

- Enhance the quality of renewable resources and approach the maximum attainable recycling of depletable resources; and

- *Practice conservation in the use of energy, maximize the use of energy efficient systems and minimize the environmental impact of energy production and use* [*italics added*].

Of specific relevance to the work of the Task Force, the Coastal Management Act (CMA, CGS 22a-90 *et seq*.), statutes pertaining to tidal wetlands (CGS Sec 22a-28 *et seq*.), and statutes pertaining to dredging and erection of structures and placement of fill in tidal, coastal, or navigable waters (CGS Sec. 22a-359 *et seq*.) support the state's policies that are applicable to crossings of Long Island Sound and the applicable DEP programs.

2.6.2 State Resources of Concern under PA 02-95 and the Executive Order

PA 02-95 and Executive Order 26 recognize that development of energy infrastructure must proceed in a manner that is protective of the environment while meeting the energy needs of the citizens of the state. As required by PA 02-95, environmental resources to be considered include, but are not limited to: all coastal resources, as defined in CGS Sec. 22a-93,[42] all points of public access and public use, locations of rare and endangered species including the breeding and nesting areas for such rare and endangered species, locations of historically productive fishing grounds and locations of unusual and important submerged vegetation.

2.6.3 Public Trust Doctrine

Under the common law public trust doctrine, the state of Connecticut holds the submerged lands and waters waterward of the mean high water line in trust for the public.

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[42] "Coastal Resources" means the coastal waters of the state, their natural resources, related marine and wildlife habitat and adjacent shorelands, both developed and undeveloped, that together form an integrated terrestrial and estuarine ecosystem. CGS Section 22a-93(7). These include: Beaches and Dunes, CGS Section 22a-93(7)(C), Bluffs and Escarpments, CGS Section 22a-93(7)(A), Coastal Hazard Areas, CGS Section 22a-93(7)(H), Coastal Waters, CGS Section 22a-93(5), Nearshore Waters, CGS Section 22a-93(7)(K), Offshore Waters, CGS Section 22a-93(7)(L), Estuarine Embayments (tidal rivers, bays, lagoons and coves), CGS Section 22a-93(7)(G), Developed Shorefront, CGS Section 22a-93(7)(I), "wetlands" and "watercourses" as defined by CGS Section 22a-38 and CGS Section 22a-93(7)(F), Intertidal Flats, CGS Section 22a-93(7)(D), Islands, CGS Section 22a-93(7)(J), Rocky Shorefront, CGS Section 22a-93(7)(B), Shellfish Concentration Areas (actual, potential or historic), CGS Section 22a-93(7)(N), Shorelands, CGS Section 22a-93(7)(M), Tidal Wetlands, CGS Section 22a-29. CGS Section 22a-93(7)(E), Water Dependent Uses, CGS Section 22a-93(16).

As the trustee of the public trust, the DEP considers public trust interests in the course of permit proceedings.

In Connecticut, pursuant to state policy,[43] the air, water, land and other natural resources are "recognized as finite and precious." It is further recognized that the state government, as trustee of the environment for the present and future generations, must conserve, improve and protect its natural resources and environment in order to enhance the health, safety and welfare of the people the state. With respect to issues related to the public benefit of energy or communications projects, the DEP has deferred to the Siting Council determination of need process for an affirmation of the need and the benefit to the citizens of Connecticut.[44]

2.6.4 Environmental Equity Movement

The environmental equity movement is in response to a growing body of evidence, nationally and statewide, indicating that low income, and racial and ethnic minority groups are exposed to higher than average amounts of environmental pollution. Environmental Equity means that all people should be treated fairly under environmental laws regardless of race, ethnicity, culture, or economic status. In December 1993, the DEP issued an Environmental Equity policy which provides, in pertinent part as follows:

> The mission of the Department of Environmental Protection is to protect the public health and welfare and to conserve, improve and protect the natural resources of the State of Connecticut. The Department carries out its mission in a way that encourages the social and economic development of the state while preserving the natural environment and the life forms it supports. Fundamental to fair administration of its programs and services is the Department's effort to reach all segments of the population.
>
> Federal and state environmental laws have accomplished a great deal in the control, reduction and elimination of pollution. However, these same laws have restricted certain types of activities and have designated some areas not suitable for development. These areas tend to be the rural towns of the state. Conversely, the evolutionary development of the cities (in terms of infrastructure, transportation, population makeup) has resulted in the state's manufacturing and industrial base being located primarily in the urban areas, where the greatest concentration of racial and ethnic minority groups and lower income persons reside. The Department recognizes that a higher number of potential sources of pollution in these areas may consequently cause a disproportionate impact on the residents.

[43] CGS Section 22a-1.

[44] Memorandum of Decision; To: Jane K. Stahl, Deputy Commissioner; From: Arthur J. Rocque, Jr., Commissioner; Date: 03/14/02; Re: Cross Sound Cable Memorandum of Decision.

> The policy of this Department is that no segment of the population should, because of its racial or economic makeup, bear a disproportionate share of the risks and consequences of environmental pollution or be denied equal access to environmental benefits. The Department is committed to incorporating environmental equity into its program development and implementation, its policy making and its regulatory activities.

Of specific relevance to the work of the Work Group and Task Force are the environmental equity issues associated with the construction and operation of electric generating units in urban centers.

2.6.5 State and Federal Environmental Review

Connecticut implements environmental policies through permit programs and other regulations that have been established to protect the state's natural resources and ecology. Jurisdiction over the state's natural resources and state permit authority resides with the DEP.

Federal regulations apply to the FERC-jurisdictional transmission facilities, as well as to certain construction activities associated with DPUC-jurisdictional transmission projects. The primary federal resource management agencies with permit granting jurisdiction include the U.S. Army Corps of Engineers (ACOE), the U.S. Environmental Protection Agency (EPA) and FERC. A number of federal Executive Orders and federal statutes require coordination with other federal and state resource management agencies, including the National Oceanic and Atmospheric Administration, National Marine Fisheries Service (NMFS), and the U.S. Fish and Wildlife Service (USFWS). In addition to federal resource agencies, FERC also seeks advisory opinions from state agencies, including the Siting Council.

The regulations in the following discussion summarize the relevant permits and programs that implement state and federal environmental protection policies and are potentially applicable to terrestrial and submarine transmission infrastructure projects.

2.6.6 Federal Permits

<u>National Environmental Policy Act</u> – Prior to issuance of any federal permit, approval, or funding, environmental review is required so that agencies are provided with adequate information to make decisions. The National Environmental Policy Act (NEPA) provides the primary framework for environmental review at the federal level for FERC-jurisdictional projects. The Council of Environmental Quality has adopted guidelines for implementing NEPA, and federal agencies, including FERC, are required to promulgate regulations for implementing NEPA relative to their programs. The purpose of NEPA is to identify and evaluate the impacts of proposed actions that could have the potential to significantly affect the environment.

Section 10/Section 404 Permit – This permit often referred to as the "Corps Permit" or the "Dredge and Fill Permit" is generally administered under a single program even though its authority stems from two separate federal statutes. Section 10 of the Rivers and Harbors Act (33 U.S.C. 401 *et seq.*) requires authorization from the ACOE for the construction of any structure in or over any navigable water of the U.S., the excavation / dredging or deposition of material in these waters, or any obstruction or alteration in a "navigable water." Structures or work outside the limits defined for navigable waters of the U.S. require a Section 10 permit if the structure or work affects the course, location, condition, or capacity of the water body. Section 404 of the Clean Water Act regulates the placement of dredged and fill material into waters of the U.S., including wetlands. The Clean Water Act authorizes the issuance of permits for such discharges as long as the proposed activity complies with environmental requirements specified in Section 404(b)(1) of the act.

The Section 404 program is administered by both the ACOE and the EPA, while the USFWS, NMFS and several state agencies play important advisory roles. In evaluating individual Section 404 permit applications, the ACOE determines compliance with Section 404(b)(1) guidelines and carries out a public-interest review. The ACOE also considers comments received from the EPA, USFWS, NMFS, and state resource agencies.

Section 7 Endangered Species Act – Section 7 of the Endangered Species Act provides that federal agencies consult with the USFWS for any action authorized, funded, or carried out by such agency with respect to activities that may jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of habitat of such species. Such interagency consultation typically occurs as part of NEPA activities and typically arises with the issuance of a Section 10/Section 404 permit.

The Marine Mammals Protection Act – The Marine Mammal Protection Act of 1972 (MMPA) was most recently reauthorized in 1994. The MMPA established a moratorium, with certain exceptions, on the taking of marine mammals in U.S. waters and by U.S. citizens on the high seas, and on the importing of marine mammals and marine mammal products into the U.S. The MMPA prohibits hunting, capturing, killing, or harassing any marine mammal, including actions that disrupt migration, breeding, feeding, or sheltering.

Magnuson-Stevens Fishery / Conservation and Management Act – Essential Fish Habitat (EFH) provisions of the Magnuson-Stevens Fishery Conservation and Management Act require that the NMFS be consulted on actions that are likely to affect EFH. Congress defined EFH as those waters and substrate necessary to fish for spawning, breeding, feeding, or growth to maturity.

Coastal Barrier Resources Act – The Coastal Barrier Resources Act (16 U.S.C. Sec. 3501-3510, October 18, 1982, as amended 1982, 1986, 1988, 1990, 1992 and 1994) protects undeveloped coastal barriers and related areas by prohibiting direct or indirect federal funding of various projects in these areas that might support development. The purpose of the Coastal Barrier Resources Act is to minimize the loss of human life, wasteful expenditure of federal funds, and damage to fish, wildlife and other natural resources of the coastal barriers by restricting future federal financial assistance for development of these areas, establishing a Coastal Barrier Resources System, considering ways in which long-term conservation of these resources may be achieved. These resources have been mapped by the Federal Emergency Management Agency along the Connecticut shoreline.

2.6.7 State Permits

Relevant DEP programs include permits for regulated activities in tidal wetlands (CGS Sec. 22a-32), stream channel encroachment (CGS Section 22a-342 *et seq*.) and for structures, dredging, or fill in state waters (CGS Sec. 22a-361) and inland wetlands and waterways. (CGS Sec. 22a-36 through 22a-45a).

Coastal Management Act – The Coastal Management Act (CMA) establishes a statewide policy of planned coastal development and authorizes towns to administer local coastal management programs. This program is administered by the DEP Office of Long Island Sound Programs (OLISP). The CMA lists a number of criteria related to structures, dredging and fill that the OLISP must consider. They include:

- Requiring structures in tidal wetlands and coastal waters to be designed to minimize their harm to coastal resources, circulation, sedimentation, water quality, flooding, and erosion;

- Disallowing filling of tidal wetlands and near shore, offshore, and intertidal waters to create new land which is otherwise undevelopable;

- Disallowing new dredging in tidal wetlands, except where no feasible alternative exists or where adverse impacts to coastal resources are minimal;

- Requiring that access to public beaches below the mean high water mark not be unreasonably impaired by structures including jetties, groins, and breakwaters;

- Encouraging the removal of illegal structures below mean high water that obstruct passage along the beach; and

- Maintaining, enhancing, or restoring natural water circulation patterns and fresh and saltwater exchange (CGS Sec. 22a-92).

When making a decision on a permit application, OLISP must also consider factors such as the potential effect on the area's natural resources, including, but not limited to, plant and animal species, the prevention or alleviation of shore erosion and coastal flooding, the use and development of all adjoining lands, the improvement of coastal and inland navigation for all vessels, the interests of the state in such areas as pollution control, water quality, recreational use of public water, and management of coastal resources, and the rights and interests of all persons concerned with the proposed activity.

Pursuant to the federal Coastal Zone Management Act of 1972 (15 CFR 930) and under its federally approved Coastal Zone Management Program, the DEP has the responsibility to determine if the issuance of a federal license which might impact Connecticut's coastal zone is consistent with Connecticut's coastal management program. Such federal consistency determination applies to FERC and the ACOE licenses.

<u>Structures/Dredging and Fill</u> – Any project proposing to dredge, fill, obstruct, encroach, erect or maintain any structure or perform work incidental to such activities seaward of the high tide line in tidal, coastal, or navigable waters of the state must apply for a DEP permit (CGS Sec. 22a-361). The law requires the DEP to consider the effect of proposed activities on: (1) indigenous aquatic life, fish, and wildlife, (2) preventing or alleviating shore erosion and coastal flooding, (3) the use and development of adjoining uplands, (4) improving coastal and inland navigation, (5) use and development of adjacent lands, and (6) the state's interests including water quality, recreational uses, and coastal resource management (CGS Sec. 22a-359).

<u>Tidal Wetlands, Inland Wetlands and Watercourses</u> – Anyone proposing to conduct a regulated activity in a tidal wetland must apply for a permit from the DEP (CGS Sec. 22a-32). Regulated activities, as defined in CGS Sec. 22a-29(3), include draining, dredging, and excavation, directly or indirectly in a tidal wetland, and building structures, driving pilings, or placing obstructions. The DEP may grant, deny, or limit the permit, based on a consideration of the effects of the proposed activity on the public health and welfare, marine fisheries, shellfisheries, wildlife, protection of life and property from floods, hurricanes, and other natural disasters, and other public policy considerations set out in the tidal wetland statutes (including, under CGS Sec. 22a-28, preservation of wetlands to protect marine commerce, fisheries, recreation, and aesthetic enjoyment) (see CGS Sec. 22a-33). In addition to the statutory criteria for each permit, the law requires the DEP to administer all coastal permitting programs in accordance with the goals and policies of the CMA.

The state permit program for inland wetlands and watercourses applies to state-jurisdictional projects and federally regulated or owned projects. Wetland commissioners within each municipality have adopted regulations consistent with state requirements for administering the 1972 Inland Wetlands Act. Municipal zoning and wetlands commissions may "regulate and restrict" the proposed location of proposed power plants and substations. (CGS Sec. 16-50x). The Siting Council certification process takes into consideration local inland wetland commission comments and regulations, but the Siting Council's jurisdiction is exclusive for electric transmission line and pipeline facilities, and appellate for generation and substation facilities. (CGS 16-50x)

<u>Stream Channel Encroachment Line</u> – Under the stream channel encroachment program, the DEP has established set-backs along approximately 270 miles of flood-prone rivers

(CGS Sec. 22a-342). Anyone building or conducting certain other activities within the set-back areas must first obtain a DEP permit. The purpose of the program is to eliminate activities that increase the chance of flooding. The set-backs are delineated on maps available from the DEP or from local town clerks. In making a decision on a stream channel encroachment line permit application, the DEP must consider the impact of proposed activities on the floodplain environment, including wildlife and fisheries habitats, and on flooding and the flood hazards to people and property posed by such activity.

Section 401 of the Clean Water Act/State Water Quality Certification – Federal law requires that an applicant for a federal license or permit (such as an ACOE permit) to conduct an activity that may result in a discharge into navigable waters obtain a state certificate (a "401 permit"). Such activity or discharge must be consistent with the provisions of the federal Clean Water Act and with the Connecticut Water Quality Standards. Generally, certification is made in conjunction with issuance of a state permit under the structures, dredging and fill statutes. In reviewing requests for water quality certification, the DEP must consider the effects of proposed discharges on ground and surface water quality, and on existing and designated uses of the waters of the state.

Threatened, Endangered, and Special Concern Species – The Natural Diversity Data Base (NDDB) is the central repository for information on the biology, population status, and threats to the elements of natural diversity in the state of Connecticut. Reported information on rare plant and animal species and significant natural communities is compiled, stored, and made available through NDDB. The NDDB currently contains information on the status of more than 600 species of plant and animals, including invertebrates, and 45 significant natural communities, which includes the Endangered, Threatened, or Special Concern species listed in Connecticut. If a proposed project may impact listed species or significant natural communities, the appropriate DEP division will provide recommendations to avoid endangered and threatened species or recommendations to minimize impacts to species of special concern and significant natural communities. A negative response from the NDDB simply means that no habitat or species of concern have been reported, not that none exist in a project area. Consultations with the NDDB should not be substituted for on-site surveys required for environmental assessments.

2.6.8 Protection of Cultural Resources

An evaluation of the potential impacts of a proposed project on historic and cultural resources is required under NEPA. Federal agencies, including FERC, must integrate any assessment and related surveys and studies required under the National Historic Preservation Act (NHPA) of 1966. (16 U.S.C. 470 *et seq.*). Federal and state requirements protect cultural resource sites on land and also submerged sites.

The Connecticut Historical Commission (CHC) is the state agency responsible for overseeing the protection of Connecticut's cultural resources. The CHC is authorized under state statutes and the NHPA. The legislature created the CHC to, among other things, study, investigate, and encourage the preservation of historic resources, including archaeological sites (CGS Sec. 10-321). Under CGS Sec. 10-321(b)(13) the CHC may "review planned state and federal actions to determine their impact on historic structures and landmarks...." Historic structures and landmarks are defined to include "sacred sites and archaeological sites." The NHPA allows states to designate a State Historic Preservation Officer. The governor designates the CHC director to act as the state historic preservation officer under the NHPA. In that capacity, the CHC is called in to advise federal agencies contemplating an action. (36 CFR 800.2(c)(1)). The CHC is not explicitly authorized to order a "reconnaissance" survey, but its role under NHPA can trigger a federal agency to make such a request.

2.7 SITING COUNCIL CERTIFICATION

2.7.1 Jurisdiction of the Siting Council

The Siting Council is authorized under the PUESA to regulate the siting of new electric transmission lines of 69 kV and above, fuel transmission lines of 200 psig and above, electric generating or storage facilities (excluding emergency generators and certain other small generators), and electric substations or switchyards of 69 kV and above.[45] Municipal zoning and inland wetland commissions have rights and responsibilities by statute concerning electric generating plants and substations. The Siting Council does not have authority over any facilities, such as interstate gas pipelines, which are FERC-jurisdictional, and only acts in an advisory capacity with the issuance of orders not contrary to FERC certification. (CGS Sec. 16-50k(d)).

The Siting Council's mission is to balance the statewide public need for adequate and reliable services at the lowest reasonable cost to consumers, with the need to protect the environment and ecology of the state and to minimize damage to the ecological, scenic, historic and recreational values. The Siting Council is funded primarily by application fees and assessments of the electric utilities, hazardous waste generators, and telecommunications providers of the state. The Siting Council has nine members: five appointed by the Governor including the chairperson, one appointed by the Speaker of House, one appointed by the President Pro-tempore of the Senate, the Chairperson of the DPUC, and the Commissioner of the DEP. By statute, at least two Siting Council members appointed by the Governor must be experienced in the field of ecology and not more than one member may have an affiliation with any utility, government utility regulatory agency, or facility under the Siting Council's jurisdiction.

Project proponents apply to the Siting Council for a Certificate of Environmental Compatibility and Public Need. The statutes prescribe the pre-application process, the

[45] The Connecticut Siting Council also regulates the siting of ash residue disposal areas, hazardous waste and low-level radioactive waste facilities, and certain telecommunications towers. Regulation of these facilities is not covered in this discussion.

application requirements, service and notice requirements, opportunities for public participation and intervention, the public hearing process, the Siting Council's decision-making process and criteria, timelines and milestones. The current administrative process was established in 1971, when PUESA was passed. Thus, the certification process predates many state and federal environmental programs, as well as Connecticut's 1998 electric restructuring legislation.

Section 16-50z of PUESA defines the conditions under which a transmission owner may exercise eminent domain, condemn, or otherwise acquire property for a transmission ROW or other infrastructure project. The statutes bar banking of land in contemplation of a future transmission facility. Except under limited circumstances and in accordance with Siting Council regulations, transmission owners or developers cannot acquire property without a Siting Council certificate.

By statute (CGS Sec. 16-50r), electric generators in the state must file an annual report to the Siting Council containing a 10-year forecast of loads and resources, including a list of planned transmission lines for which proposed route reviews are being undertaken or for which certificate applications have already been filed. The Siting Council, in turn, may issue a report assessing the overall status of loads and resources in the state. This report (which is currently available on the Siting Council's web site) is a compilation of information provided by resource owners; the Siting Council does not have an independent resource planning function.

2.7.2 Role of Other State Agencies

The current certification process establishes the mechanism by which other resource agencies are consulted on the proposed project. By statute, the Siting Council must solicit written comments from other informed state agencies: the DEP, the Department of Public Health, the Council on Environmental Quality, the DPUC, the Office of Policy and Management (OPM), the Department of Economic and Community Development (DECD), and the DOT. In addition, each applicant must include in the application a copy of each written federal, state, regional, and municipal agency position on such route or site. (CGS Sec. 16-50l(a)-(h)).

While the DEP is a member of the Siting Council and does provide technical input into the siting process, the DEP's role in the certification process is distinct from its role in issuing permits. The question as to whether a project is necessary for public need or benefit is typically answered by the Siting Council before the DEP processes a permit, and is outside of the DEP's permitting purview. If the DEP determines that the permit applications for a proposed facility meet all regulatory requirements, the DEP must issue those permits.

2.7.3 Federal Preemption of Interstate Gas Pipelines

Federal law regulates the siting of interstate natural gas pipelines (Natural Gas Act, 15

U.S.C. Sec. 717-717w). The U.S. Supreme Court and the U.S. 2nd Circuit Court of Appeals have held that the law and regulations under the law control preemption of state actions by FERC. In *Schneidewind v. ANR Pipeline Co*.,[46] the Supreme Court held that the Natural Gas Act confers upon FERC exclusive jurisdiction over transportation and sale of natural gas in interstate commerce for resale. NEPA provides the primary framework for environmental review at the federal level. FERC encourages cooperation between interstate pipelines and local authorities.[47] The state retains the obligation to perform a coastal zone management consistency review and water quality certification. Should the state issue an objection to the Coastal Zone Consistency Statement, project proponents may request that the Secretary of Commerce override this objection. In order to grant an override request, the Secretary must find that the activity is consistent with the objectives or purposes of the Coastal Zone Management Act, or is necessary in the interest of national security. In addition, as the holder of title to land waterward of the mean high water mark in trust for the people of Connecticut, an entity proposing to install a cable or pipeline in Long Island Sound must have the permission of the state through the permitting process. Furthermore, it is the position of the DEP that FERC cannot grant an applicant eminent domain authority over state land.

2.7.4 The Certification Process

The Siting Council has developed application guides for electric generating facilities, electric substation facilities, and electric and fuel transmission line facilities. These application guides incorporate all the statutory information and notice requirements (CGS Sec. 16-50l(a)) and also request general information typically needed by the Siting Council for its determination of public need and convenience and impact on the environment, ecology, and scenic, historic and recreational values. The application guides are intended provide the Siting Council with sufficient technical information for its deliberations without unreasonably overextending a project developer's risk.

Upon receipt of a compliant application, the Siting Council schedules public hearings to commence no sooner than 30 days and no later than 150 days of receipt of the

[46] 485 U.S. 293 (1988)

[47] *Maritimes & Northeast Pipeline, L. L. C., Algonquin Gas Transmission Co*., 2001 WL 1638755 (FERC) (2001). In *National Fuel Gas Supply Corp. v. Public Service Commission of New York* (894 F. 2d 571 (1990)), the New York Public Service Commission required National Fuel to obtain a "certificate of environmental compatibility and public need" to build its pipeline. National Fuel sought to enjoin the New York Public Service Commission from regulating the pipeline. Citing *Schneidewind*, the court held for the gas company, finding that even a site-specific environmental review is "undeniably a regulation" of the interstate pipeline that "would certainly delay and might well...prevent the construction of federally approved interstate gas facilities." The court noted that both federal and state regulation called for environmental review of the project and that matters sought to be regulated by the New York Public Service Commission were thus directly considered by FERC. The court found that because FERC has authority to consider environmental issues, states many not engage in concurrent site-specific environmental review. The consequence of such a review that would allow all the sites and all the specifics to be regulated by agencies with only local constituencies would be to delay or prevent construction that has won approval after federal consideration of environmental factors and interstate need.

application. For electric transmission line or fuel transmission facility applications, the Siting Council must render an opinion within twelve months of the filing of the application, with a possible six-month extension by consent of the applicant. (CGS Sec. 16-50p(a)). Under the statutory process and timelines, projects are reviewed *in seriatum*; there is no explicit statutory mechanism to group and compare the benefits and environmental impacts of competing proposals. Although an application for a jurisdictional gas or electric transmission line must provide information on alternative routes considered, there is no statutory requirement for the Siting Council to weigh the benefits and environmental impacts of the project against non-transmission alternatives that address the same need (such as a load response initiative) or against the "no-action" alternative. The applicant is not required to provide alternatives that it is not capable of implementing. For example, a transmission owner cannot put forth generation alternatives, and vice versa. The applicant is also not required to assess the cumulative impact of the proposed project aggregated with other pending projects or policy/regulatory changes. These issues are further discussed in Section 4.1 and 4.2.

Following issuance of the certificate, the applicant must prepare a Development and Management (D&M) Plan for the Siting Council's review and approval. The D&M Plan provides a mechanism for the Siting Council to enforce the provisions of a decision and order, including appropriate environmental monitoring, mitigation measures and other conditions of the certificate.

2.7.5 Certification Criteria

The statutes prescribe the criteria that the Siting Council must consider in issuing a certificate. (CGS Sec. 16-50p). An overhead transmission line can not be approved without a finding of "public need" and the public need must outweigh the adverse effects on the natural environment, ecological balance, public health and safety, scenic, historic and recreational values, forests and parks, air and water purity and fish and wildlife. (CGS Sec. 16-50p(a)). Traditionally, public need has been based on the concept of public convenience and necessity. Prudence, or economic impact on ratepayers, is also considered by the Siting Council under the "need" test, as well as the economic effects of reliability enhancements. In contrast, an underground or underwater transmission line shall not be approved unless the Siting Council finds a "public benefit" for the facility and that this public benefit outweighs the adverse effects of the project. (CGS Sec. 16-50p(c)(2)). A public benefit exists if the facility "is necessary for the reliability of the electric power supply of the state or for the development of a competitive market for electricity." Thus, overhead lines must pass a stricter test to be approved by the Siting Council. It is within the Siting Council's jurisdiction to determine which parts of the line, if any, should be underground and whether the overhead portions are cost-effective.

In balancing energy reliability with protection of the environment, the Siting Council must assess each adverse and beneficial impact, and determine "whether alone or cumulatively with other effects, … conflict with the policies of the state concerning the natural environment, ecological balance, public health and safety, scenic, historic, and recreational values, forests and parks, air and purity and fish and wildlife." (CGS Sec. Sec. 16-50p(a) and Sec. 16-50p(c)). The test of whether environmental impacts are disproportionate with the public need or benefit is subjective.

In approving an application for a transmission line, the Siting Council must also:

- Identify its environmental impacts that conflict with state policy;
- Determine that these impacts are not sufficient reason to deny the application;
- Find that the line will not unnecessarily jeopardize people or property along its route; and
- Find that the line conforms to a long-range plan for expanding the power grid and will benefit electric system economy and reliability.

2.8 PROPOSED ENERGY INFRASTRUCTURE PROJECTS

The following sections provide a description and status of infrastructure projects which have been recently proposed or constructed. These projects are germane to Task Force and Working Group objectives and include all Long Island Sound crossings and the Bethel to Norwalk line, as well as selected relevant projects outside of Connecticut.

2.8.1 Proposed Electric Transmission Projects

<u>CL&P Bethel-Norwalk Transmission Project</u> – In the early 1970s, CL&P developed plans for a 345 kV loop into NOR. CL&P began its construction in 1977-78 with a 345 kV line from Long Mountain to Plumtree Junction. Subsequently, CL&P reinforced the other portions of the existing 115 kV system.[48] CL&P experienced unexpected peak loads in 1999 and again in 2001, and a voltage collapse from which the system nearly did not recover on June 11, 2000. CL&P filed an Application for a Certificate of Environmental Compatibility and Public Need to the Siting Council to construct a 345 kV transmission line from the Plumtree Substation in Bethel to the Norwalk Substation in Norwalk (Phase I). CL&P also proposes to enhance the reliability of service to SWCT by completing a 345 kV loop from Norwalk to Beseck Junction in Wallingford (Phase II), expected to be filed in early 2003.[49] The Bethel-Norwalk 345 kV proposal has been under review by the Siting Council in Docket No. 217, and is subject to the moratorium of PA 02-95.

CL&P's preferred Phase I project (referred to as the 345/115 kV OH Proposal) would be constructed within an existing 115 kV line's ROW along the 20-mile path. A ROW width expansion would be needed along much of the ROW, but could be minimized by

[48] Siting Council Dockets Nos. 5, 26, 57, 105, and 141.
[49] ISO-NE recommended that CL&P add a 345 kV line between Stamford and Norwalk to Phase II.

combining the existing 115 kV line and the new 345 kV line onto a single set of new, higher structures.

CL&P also presented two alternative designs (Table 8) that incorporate underground cable for either the 345 kV or the 115 kV line. CL&P considered two underground cable technologies: high-pressure fluid filled (HPFF) cable and solid dielectric cable using cross-linked polyethylene (XLPE).

- The 345 kV OH Alternative would remove the 115 kV line from the existing ROW and replace it underground using XLPE cable along public streets, which would allow the new 345 kV line's structures to be lower than in the preferred proposal. CL&P considers underground XLPE cable to be well proven at the 115 kV rating and preferable in this instance to HPFF. The chief disadvantage of the 345 kV OH Alternative is that two construction efforts would be required and the total capital cost would be higher than the preferred proposal.

- The 345 kV Underground (UG) Alternative would bury the entire 345 kV line using XLPE cable along public roadways and leave the existing 115 kV line intact. Two groups of three 345 kV cable would be used to achieve a capacity rating of about 60% of a single 345 kV overhead line without overheating problems. CL&P believes underground XLPE is not fully proven at 345 kV and has reliability concerns with XLPE cable at this voltage level, but XLPE is preferred because it avoids any environmental risks of insulating fluid leaks. The cost would be similar to the 345 kV OH Alternative.

- The Siting Council has requested CL&P to present to it several additional alternatives that include both overhead and underground sections; and with respect to the overhead sections, the use of lower height wood pole structures through wooded areas where ROW widening is preferable to increased tower visibility, and the use of taller towers where ROW widening must be minimized. These alternatives will be presented to the Siting Council when it resumes hearings in January 2003.

Table 8 – CL&P Transmission Proposal and Alternatives

	345/115 kV OH Proposal	**345 kV OH Alternative**	**345 kV UG Alternative**
Right-of-way (ROW)	Expand existing ROW	Expand existing ROW and add along public roadways	Add along public roadways
Capital Cost (2002 $s)	$127 million	$185 million	$182 million
Life Cycle Cost (2004 $s)	$195 million	$274 million	$ 274 million

The capital costs provided by CL&P include substation modifications and the cost of obtaining additional ROW. Life cycle costs include substations, annual carrying charges for capital costs, operations and maintenance (O&M), energy losses, and capacity costs, and are expressed in 2004 dollars.

An alternative transmission solution intended to replace the proposed Phase I 345 kV project with a two-line 115 kV underground project was proposed by Synapse Energy Economics on behalf of the four towns of Bethel, Redding, Weston, and Wilton. This two 115 kV alternative may meet SWCT's needs for the next few years while avoiding the visual impacts and higher costs of the 345 kV transmission towers.

ISO-NE performed an initial technical evaluation of CL&P's proposed 345 kV Bethel-Norwalk and Norwalk-Beseck Junction transmission projects and reported those findings in the *Connecticut Reliability Study – Interim Report* (Interim Report), published in January 2002. The Interim Report identified the limitations of the existing transmission system and developed a design basis for a transmission solution including an assumed peak load of 27,700 MW in 2006 and 30,000 MW at some undefined future point in time.[50] The Interim Report considered the two 115 kV alternative to the 345 kV loop as well as other alternatives such as utilizing real-time dynamic line ratings, flexible AC transmission system devices, and a 230 kV loop. Initial modeling results indicated line overload, voltage, and short circuit problems would persist for these alternative designs.

The final results (included as Appendix G) were presented at a TEAC meeting on December 5, 2002 (TEAC 13). The presentation covered the performance of the proposed project at different load levels, and included transfer, thermal, stability, and short circuit analyses. In the TEAC 13 meeting, ISO-NE reiterated its support for near-term improvements of load response, DG, C&LM, and transmission upgrades throughout SWCT. ISO-NE used the Power Technologies PSS/E load flow software package to perform the technical analyses, including contingency cases, of the existing 115 kV system, CL&P's proposed 345 kV loop, and the alternative two 115 kV loop.[51]

The existing system was found to exceed emergency ratings under a variety of contingency events. The study also found voltage and short circuit problems with the existing system.

ISO-NE tested the 345 kV loop proposal and the two 115 kV line option under a variety of conditions, and concluded that the 345 kV loop was its recommended solution. The benefits of the 345 kV loop would include improving reliability within SWCT, reducing congestion (and hence ratepayer) costs, relieving high loading on the existing 115 kV lines, reducing dependence on local generation units, establishing the infrastructure for new generation in that sub-area. The 345 kV project would provide at least five years of additional load growth margin beyond the two 115 kV option.

[50] The 27,700 MW peak load is higher than the CELT forecast of 25,817 MW in recognition that the actual 2001 peak load was 1,317 MW above the CELT forecast value that assumes normal weather conditions.

[51] At TEAC 13, ISO-NE recommended that Phase II of the 345 kV loop include a 345 kV extension from Norwalk to the Glenbrook substation in Stamford and a 115 kV transmission line between Norwalk Harbor and Glenbrook.

At TEAC 13, ISO-NE provided a comparison of both the 345 kV loop and the two 115 kV transmission line options (Table 9 and Table 10). Both alternatives were tested against a New England load of 27,700 MW and at an increased load of 30,000 MW. According to the *2002 CELT Report* forecast, a peak demand of 27,758 MW will be reached in 2011, under expected normal summer weather conditions. The *2002 CELT Report* also includes a demand forecast for summer 2003 under extreme weather conditions, and forecasts that there is a 10% probability that the peak demand will exceed

Table 9 – Summary of Problem Occurrences

Case	Normal Overloads[52]	Contingency Overloads[53]	Voltage Violations[54]	Non-Convergent Contingencies[55]
Base – 27,700 MW	36	82	31	54
Phase I – 27,700 MW				
345 kV Plan	4	16	0	16
Two 115 kV Plan	7	18	4	19
Phase II – 27,700 MW				
345 kV Plan	0	0	0	0
Two 115 kV Plan	0	2	0	0
Phase II – 30,000 MW				
345 kV Plan	0	1	0	0
Two 115 kV Plan	0	8	0	0

Table 10 – System Transfer Capability

Case	NOR (MW)	SWCT (MW)
Base[56]	850-1,150	2,050-2,400
Phase I		
345 kV Plan	1,100-1,400	2,300-2,600
Two 115 kV Plan	1,050-1,300	2,150-2,500
Phase II		
345 kV Plan	n/a	3,050-3,450
Two 115 kV Plan	n/a	3,000-3,200

[52] Number of occurrences could be same line for different dispatches.
[53] Number of different line segments that show up at least for one contingency.
[54] Number of different busses that show up for at least one contingency.
[55] Number of different contingencies that do not result in a solved case.
[56] Base case represents 2004 with Glenbrook statcom in service.

26,150 MW. It should be noted that the actual peak demand for 2002 was 25,348 MW. The 2002 forecast for expected normal summer weather was 24,200 MW and the extreme weather forecast was 25,530 MW.

ISO-NE intends to implement a series of near-term LRPs that will begin on March 1, 2003. The near-term LRPs are discussed in section 2.11.4 of this Assessment Report. ISO-NE also assessed the generation resources required to assure reliability in SWCT without the 345 kV loop, and found that all of Connecticut's existing resources are required in 2003 when transmission reliability criteria are considered, plus 100 MW to 300 MW of additional resources in SWCT.

<u>CL&P 138 kV Cable Replacement Project</u> – Line 1385 links the CL&P system with the Long Island Power Authority (LIPA) system and has been in service for over 30 years. Last summer, line 1385 was critical to SWCT reliability when lines 1730 and 1710 between Devon and Norwalk failed. In November 2002, four of the seven cables were severed by a barge. CL&P and LIPA have investigated the damage, and a decision has been made to expedite repairs such that the full capacity of the cable system will be available prior to July 2003.

CL&P and LIPA intend to replace the seven (six energized and one spare) existing fluid-filled paper insulated single-phase cables with three, three-phase XLPE (solid dielectric) cables. The new 1385 line will be 12 miles long, and have a capacity of 300 MW, equal to the existing cables. The new cables will be buried within the existing cable corridor. The permitting process is underway in both Connecticut and New York. In Connecticut, the Siting Council issued a Certificate of Environmental Compatibility and Public Need for CL&P for the project on September 9, 2002. This cable replacement project is exempt from the moratorium provisions of PA 02-95.

<u>Cross-Sound Cable</u> – TransEnergie US, a subsidiary of Hydro-Quebec, installed the 24-mile TE-CSC cable last spring between New Haven and the Shoreham site in Brookhaven, New York. It is an HVDC cable with 330 MW of capacity. TE-CSC is connected to the 345 kV system in New Haven and the 138 kV system at Shoreham, using bi-directional converter facilities. TE-CSC will facilitate scheduled transfers of power between the New England and New York grids. The initial transmission rights were purchased by LIPA, and ISO-NE and the New York Independent System Operator (NYISO) will coordinate the actual operation. TransEnergie will not control the flows on TE-CSC, and therefore will not be able to exercise market power. As a merchant transmission line, rates were set through an open season rather than through a FERC rate-base mechanism. FERC-approved market rates reflect the differential between electric power values between the two markets. TransEnergie is therefore exposed to market risks, as well as construction and operation risks.

TransEnergie's original application to the Siting Council in Docket 197 was denied in March 2001, primarily due to concerns about threats to the oyster beds in New Haven harbor. TransEnergie responded to the DEP's concerns and proposed an alternate route, from the shoals area to the Federal Navigation Channel in New Haven harbor. The project received Siting Council approval in January 2002 in Docket 208. The cable was installed using jet-plow embedment techniques, but seven portions of the route did not achieve the required 48-foot depth in New Haven harbor. TransEnergie intends to resolve the six portions that are in soft sand during the 2002/03 winter, while the seventh portion, which encountered bedrock, is still being evaluated. TE-CSC has been authorized to be energized for emergency use as ordered by the DOE, but power has not flowed across Long Island Sound because of the failure to meet the ACOE and DEP permit conditions.

<u>NeptuneRTS</u> – The Neptune Regional Transmission System project (NeptuneRTS), sponsored by Atlantic Energy Partners, LLC, envisions several thousand miles of HVDC cables that would connect generation in Maine, New Brunswick, and Nova Scotia with markets in Boston (1,200 MW), New York City (1,800 MW), Long Island (600 MW), and Connecticut (1,200 MW). FERC approved NeptuneRTS's Phase I application for merchant transmission service in July 2001, but the timing for construction of NeptuneRTS is uncertain.

Phase I would consist of two 600 MW connections from Sayreville, New Jersey to Manhattan and to the south shore of Long Island. The project is still pending public utility and environmental regulatory approvals by New York State, New Jersey, and the ACOE. A cable across Long Island Sound would be the final leg of Phase IV of the project, connecting Connecticut with Maine and Maritimes Canada. No applications have been filed with the Siting Council or the DEP for this project.

<u>Connecticut Long Island Cable</u> – NU filed an application to sell transmission rights on a proposed 300 MW HVDC merchant transmission cable to be built between Norwalk and Hempstead Harbor or Oyster Bay on Long Island. NU received FERC approval for the Connecticut Long Island Cable (CLIC) project in March 2002, subject to conditions to keep the project financially separate from other businesses and to transfer the scheduling authority to ISO-NE and the NYISO. Based on a weak market response during NU's open season solicitation, NU has decided not to pursue this project. NU withdrew its FERC application on November 25, 2002.

2.8.2 Proposed Gas Pipeline Projects

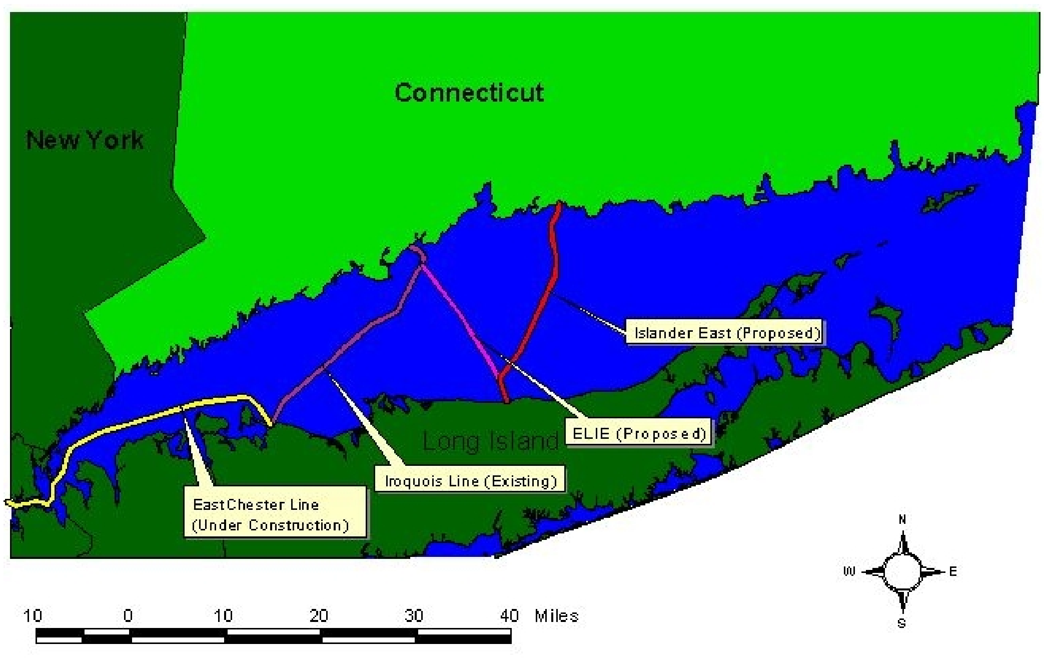
There have been two pipeline projects across Long Island Sound proposed in the past two years: the Islander East project sponsored jointly by Duke Energy and KeySpan Energy, and the Eastern Long Island Extension (ELIE) sponsored by Iroquois. Both of these projects would establish a physical link between southern Connecticut and Long Island, thereby allowing gas originating from Atlantic Canada to flow into the Long Island Facilities System.

<u>Islander East</u> – The proposed Islander East project is seeking to construct a new 24-inch to 30-inch interstate pipeline from southern Connecticut into Long Island. The receipt point for Islander East would be on Algonquin in Cheshire. The pathway would extend

27.8 miles through southern Connecticut and then 22.6 miles under Long Island Sound before terminating at Wading River near Brookhaven, Long Island. Algonquin has proposed a concurrent upgrade to its C-lateral facilities in Connecticut to enable it to "lease" the requisite capacity to Islander East. Islander East's proposed initial capacity is 285 MDth/d, but could be expandable to 445 MDth/d. The project received FERC approval, issued on September 19, 2002, despite requests by the Siting Council and the Attorney General to refrain from approving new Long Island Sound crossings until the Task Force had completed its analysis. Subsequently, in October 2002, the DEP issued a determination of non-consistency with respect to the State's Coastal Zone Management Program. In response, Islander East appealed to the U.S. Secretary of Commerce to overrule the DEP's decision. Such appeal is pending. In addition, a 401 Water Quality Certificate, and state permit applications have been submitted to the DEP for the pipeline and are pending. The DEP is precluded from issuing state permits until the moratorium expires. In addition, on November 7, 2002, FERC granted a motion for rehearing of the September 19, 2002 order for the limited purpose of allowing further consideration of objections and exceptions to the order, until January 27, 2003.

Eastern Long Island Extension – Iroquois' ELIE project is designed to increase delivery capacity to eastern Long Island to meet the area's anticipated growth in natural gas demand arising from proposed new generation and residential conversions to natural gas (Figure 8). ELIE's proposed facilities include a new 20,000-hp compressor station on

Figure 8 – Locations of Proposed Pipelines across Long Island Sound[57]



[57] Sources: Applications of Algonquin and Islander East to FERC, CP01-387-000 and CP01-384-000, respectively; Application of Iroquois Gas Transmission System, L.P. for Certificate of Public Convenience and Necessity, FERC docket number CP02-52-000; and http://www.iroquois.com/igts/pix/eli.jpg.

Iroquois' existing mainline in Milford and the construction of 29 miles of 20-inch pipeline from Milford to a new interconnection point with KeySpan Energy in Brookhaven, New York. ELIE's initial delivery capacity is 175 MDth/d, and is scheduled to be completed by November 2004. Iroquois submitted applications to FERC and to the Siting Council in December 2001. A Draft Environmental Impact Statement was issued on August 23, 2002, and FERC issued a Preliminary Determination for the ELIE Project September 19, 2002. Citing the need to allow market participants the time to consider FERC's preliminary determination on non-environmental issues for the ELIE and the Certificate of Public Convenience and Necessity for the Islander East project, in October 2002 Iroquois requested that FERC defer action on its application until January 2003 and made a similar request of the Siting Council. Iroquois has not submitted any permit applications to the DEP for the ELIE.

Eastchester Expansion – Iroquois' Eastchester Expansion is located in Long Island Sound, but fully within New York jurisdictional waters. It is designed to increase deliverability by 220 MMcf/d across Long Island through the installation of two new compressor stations, upgrades to its three existing compressor stations, and the construction of a 30-mile lateral running from a point on the mainline at Northport, Long Island, westward across Long Island Sound, and into the Bronx where it will tie into the New York Facilities System. The primary market for this gas is the power plant expansions within the New York City load pocket. Iroquois' Eastchester Expansion is presently under construction and is scheduled for commercial start-up in 2003. Iroquois has publicly announced that the Eastchester gate station is the first new meter facility in New York City in about forty years.

Hubline – Elsewhere in New England, Duke Energy has proposed the Hubline and M&N Phase III and IV projects to facilitate greater flow of gas from Atlantic Canada into New England. Hubline will begin at a point on M&N's proposed mainline expansion in Beverly, Massachusetts and run 34.8 miles across Boston harbor to Algonquin's pipeline facilities in Weymouth, Massachusetts. The project will create a direct route for gas to flow into the Algonquin system and subsequently facilitate gas flow from the Scotian Shelf into southern New England. The project has recently finalized outstanding environmental permit issues, and construction began in the fall of 2002.

2.9 ELECTRIC TRANSMISSION TECHNOLOGY

Overhead electric transmission lines and their ROW mark the landscape throughout Connecticut and the U.S. as a whole. Whereas some commercial and virtually all new residential subdivisions have begun using underground distribution lines in recent years, underground high-voltage transmission cables in Connecticut are limited to small sections in Hartford, New Haven, Stamford, Danbury and Norwalk and to some small generator interconnections. To date, cable accessibility restrictions, maintenance requirements, technical limitations, and the availability of existing ROW for overhead lines have restricted use of high voltage underground cables to a few urban areas and generator interconnections. Connecticut law (CGS Sec. 16-50t(a), requires the Siting

Council to prescribe and establish reasonable regulations and standards as it deems necessary and in the public interest relating to "the elimination of overhead electric transmission and distribution lines over appropriate periods of time in accordance with existing applicable technology and the need to provide electric service at the lowest reasonable cost to consumers."

CGS 16-50r(b) mandates that the Siting Council commission periodic reports on the comparative life-cycle costs of underground versus overhead transmission lines. These studies (the Life-Cycle Cost Studies),[58] based on an analysis of 115 kV line only, concluded that initial construction costs for underground transmission lines are five to six times as expensive as overhead lines. When O&M costs and losses are included, the life-cycle cost of a typical single-circuit underground line is estimated to be three to four times that of an overhead single-circuit line, and the life-cycle cost of a double circuit underground transmission line is five times as much as for overhead double circuit lines.[59] It is important to note that actual cost differentials are very site-specific and may also be a function of line voltage, for example, the estimated cost of the Bethel-Norwalk 345 kV underground project is higher than the overhead alternative. Although both underground and overhead components have experienced incremental improvements in performance through industry's greater attention to quality and competitive pricing, the reported differential between underground and overhead lines has not changed appreciably between the initial 1996 study and the 2001 update.

2.9.1 Overhead Electric Transmission

Transmission lines are generally designed and built to provide safe, reliable performance over a life of at least 35 to 40 years. All electric transmission lines are designed to comply with the National Electrical Safety Code (NESC). NESC establishes worker safety requirements for line maintenance, ROW requirements, engineering design criteria for conductors and towers, and other safety, operational and performance specifications. The height and ROW requirements of NESC ensure that swinging conductors do not come in contact with nearby buildings or vegetation, even during worst-case line-sag scenarios.

Nearly the entire electrical grid in the U.S. and the world consists of overhead AC lines. As a rule of thumb, a doubling in voltage capacity corresponds to a 2.5 to 3.5-fold increase in power delivery capacity.[60] The capacities of typical overhead AC transmission lines are summarized in Table 11. However, the amount of power that can be reliably delivered on a specific transmission line is often governed or directed by its

[58] Acres International Corporation, July 1996, *Life-Cycle Cost Studies for Overhead and Underground Electric Transmission Lines*. Prepared for the Connecticut Siting Council. Acres International Corporation, May 2001, *Update of Life-Cycle Cost Studies for Overhead and Underground Transmission Lines-1996*. Prepared for the Connecticut Siting Council.

[59] The life-cycle cost estimates and the projected costs of the proposed Bethel-Norwalk 345 kV project are discussed in Section 4.3.1.

[60] Transmission losses are a function of the square of the voltage.

interactions with other lines in the AC network.[61] Overhead HVDC lines have been used primarily for long-distance, high voltage transmission, where their asynchronous operation and low losses can be an advantage. A HVDC transmission interconnection does not contribute to the available fault duty on the AC system; moreover, HVDC interconnection does not provide valuable system support immediately following a contingency as does an AC interconnection.

Table 11 – Voltage and Power of AC Transmission Lines[62]

Voltage (kV)	Power (Approx. MW)
69	50-100
115	150-300
230	300-450
345	1000-2,000
500	2000-3,000

Capacity may be added to existing overhead lines by raising operating voltage or increasing the size or number of conductors. Capacity additions are typically limited by initial structural design and conductor clearances, and may require additional widening of ROWs and/or increasing tower height. Line span (the distance between two towers) at 115 kV is usually about 600 feet and can be as long as 1,000 feet; at 345 kV line spans are usually 600 to 700 feet, and can be as long as 1,000 feet. Table 12 summarizes transmission line design parameters associated with each of the three main types of transmission structure design: pole, tower, and H-frame.

Table 12 – Overhead Transmission Line Design Options[63]

Voltage	Design	ROW Width (ft)	Height (ft)	Line Cost ($ million / mile)
115 kV	Pole	90	75-85	$0.7-1.1
115 kV	Tower	90	95	> $1.1
115 kV	H-Frame	90	70	$ 0.6
345 kV	Pole	120-150	110-130	> $1.7
345 kV	Tower	170	140	> $2.2
345 kV	H-Frame	170	85	$ 0.9

[61] The maximum capacity of a line for normal operation is determined by its thermal limit – its ability to dissipate the heat generated by electrical losses. This value may be substantially reduced to ensure satisfactory response of all components of the AC network to a contingency event such as the loss of a transformer.

[62] Data provided by CL&P. The thermal rating of a specific line depends on a number of factors including the type and size of conductor and the number of conductors.

[63] Information provided to the Working Group by CL&P – Transmission Line Options for Overhead and Underground Facilities.

Structures support the lines on insulators made of ceramic disks or non-ceramic rods that insulate the lines from the rest of the tower. Ceramic insulators are an old technology; non-ceramic insulators have several advantages, primarily decreased weight and increased strength. Lightning arresters and surge arresters, usually a series of air gaps or semiconductor devices, improve reliability by dissipating impulse or switching surge over-voltages on the line. Shield or sound wires and ground wires, which run above and parallel to the conducting wire, serve to shunt lightning strikes from the conducting wire to the ground.

2.9.2 Environmental Impacts of Overhead Electric Transmission

Vegetation and Wildlife Impacts – Overhead transmission line ROWs usually involve clearing corridors of vegetation to remove trees and tall shrubs. Clearing within previously undisturbed areas can significantly alter wildlife habitat, converting, for example, forest to open grassland or shrubland. Non-native species often invade recently cleared corridors and out-compete native vegetation. Once established in the ROW, the non-native species may invade the adjoining floral communities, to the detriment of those areas. The dominance of non-native invasive species reduces the floral species diversity and in turn reduces the diversity of the faunal community. ROWs may reduce core habitat area (interior forest habitat that is free of edge effects) necessary to support a breeding population of locally important wildlife, including rare, threatened, or endangered species.

Transmission line ROWs may have beneficial impacts on certain wildlife habitat. ROWs serve as corridors for wildlife movement and provide scrub-shrub habitat and edge habitat that is beneficial to some wildlife species. Wooded wetlands can be converted to scrub-shrub wetlands or wet meadows. These may increase habitat diversity but care must be taken that the core habitat afforded by wooded wetlands is not lost.

The impacts to streams and rivers also have to be considered. As trees are removed and solar penetration increases, watercourses become susceptible to the negative impacts of thermal pollution. Streamside trees also provide stability to stream banks. In their absence, bank erosion usually increases. Eroded sediments may travel long distances downstream or out into Long Island Sound, creating far-reaching damage to a variety of ecosystems. The full function of streamside trees can often not be replicated with shrubs or smaller tree species. Loss of vegetation and even minor topographical changes within 100 feet of a vernal pool (a type of watercourse by definition, C.G.S. Sec. 22a-38) can alter water temperatures and duration of inundation, which may affect amphibian breeding populations.

Maintenance of ROWs requires periodic cutting and/or herbicide applications. Impacts from herbicides are dependent on the variety used and the care taken in applying them.

Loss of wildlife habitat can be mitigated through naturalization, the use of low-growing (less than 20 feet tall) native plants that help reestablish a healthy ecosystem. Depending on the type and extent of original vegetation lost, replanting ROW compatible species may or may not fully compensate for the impact. A naturalized ROW is more aesthetically pleasing than one that is treated regularly using herbicides and/or tree cutting to keep tall plants from growing into power lines. The ROW can be naturalized with native plants that are suitable for wildlife habitat and forage, and do not exceed the plant height restrictions. A naturalized ROW needs less maintenance and therefore reduces costs and the frequency of intrusion. Naturalized ROWs also promote biodiversity and provide food and shelter for native wildlife.

<u>Wetlands and Water Resources</u> – Wetland and water resources will be impacted to varying degrees coincident with the installation of an overhead transmission line. Construction requires, at a minimum, access roads, construction areas for each structure installation and pulling sites. This construction gives rise to both short- and long-term impacts to wetlands and water resources.

Short-term impacts from construction generally result from erosion and sedimentation. Appropriate use of erosion and sedimentation controls will greatly reduce impacts from sediment. Short-term impacts such as minor sediment accumulation and turbidity may cause some disruption that is not permanent.

Some erosion and sedimentation with longer lasting consequences are a concern with large-scale projects. Within watercourses, erosion and sedimentation may impact stream stability and health. Once destabilized, it may be difficult to repair any such damage in a manner that is fully functional and self-sustaining. Long-term, measurable sedimentation within wetlands may retard or prohibit plant growth. This type of disturbance provides an increased opportunity for the establishment of non-native invasive plant species. Proper management practices can mitigate the construction impacts. However, on steep terrain, and/or where vegetation has failed to stabilize the soil, and/or where unauthorized use of recreational vehicles is common, erosion and sedimentation may be a persistent problem.

Stream diversions, and alteration of wetland vegetation or soils within the ROW are likely to have some effect on stream and wetland habitat and function. The nature of this effect will depend on a number of factors, including the functional integrity of the resource affected, the nature of the alteration, and the extent of the mitigation and minimization measures employed to reduce impact. In the absence of site-specific information, the impact, if any, cannot be determined. The elimination of tall vegetation for the length of the line will negatively impact woodland resources, which, depending on the magnitude of the elimination, may adversely affect those species that depend on them. With regard to impacts from structures, depending on structure type, height and line voltage, the structures supporting the conductors can be located as much as 1,000 feet apart. This can provide flexibility in avoiding sensitive resources, although some of these resources may extend continuously for more than 1,000 linear feet and thus cannot be avoided unless locational factors permit longer spans. Additionally, beyond the ¼ acre construction envelope for each pole, access roads and pulling stations are also needed, which may reduce this flexibility. By optimizing structure and construction envelope locations, wetlands and vernal pools may be straddled, thereby avoiding or minimizing impacts.

Visual Impacts – Visual impacts are associated with cleared ROWs and structures such as transmission poles or towers that may be as much as 140 feet high. The towers, shield wires, and conductors, which are typically about an inch in diameter, may be visible for some distance, depending on the height, type, terrain, and surrounding vegetation or buildings. In hilly terrain, the cleared corridors may be visible for several miles. Overhead transmission lines that are visible alter the character of the surroundings. Visual impacts may be particularly adverse where the viewshed includes historic districts or landmarks. For example, experts contracted by the municipalities have determined that CL&P's proposed Bethel-Norwalk overhead alternatives are expected to impact the visual integrity of the Wilton Center Historic District, the Lambert Commons Historic District, the Cannondale Historic District, and the Georgetown Historic District.[64] The monopole or tower designs have no physical characteristics or design features that relate them to a historic landscape; a wooden H-frame design may be more compatible with a low-rise built environment, however these lower profile designs must include a wider ROW. Additional visual impacts are also possible on numerous residential neighborhoods, and several open space preserves.

Visual impacts of a transmission line can be wholly or partially mitigated through choice of structure type and route selection. In general, wider ROWs are required for higher voltage lines and lower types of structures, such as the H-Frame design (see Table 12). In areas where the width of the ROW is constrained, taller tower type structures may be more suitable. Careful routing of the lines, maximizing tower spacing, and using vegetation buffers to screen ROWs can also minimize the visual impact. For example, routing lines along contour lines in hilly terrain, rather than across contour lines, may reduce visibility of the ROW and structures. However, once the towers exceed the surrounding trees, the ability to minimize the visual impacts decreases substantially.

Health Effects – Health concerns associated with overhead electric transmission typically focus on the potential effects of electric and magnetic fields (EMF) generated around such lines.[65] The EPA initially declared power line EMF to be a possible carcinogen in 1990; the agency later concluded that there was not enough evidence to support this declaration. A 1994 report from the American Medical Association (AMA) Council on Scientific Affairs stated, "Electric and magnetic fields from power lines are of low energy and not mutagenic." The Council noted that "no scientifically documented health risk has been associated with usually occurring levels of electromagnetic fields," although it recommended that the AMA continue to monitor developments and issues related to the effects of EMF. On behalf of the California Public Utilities Commission, three scientists

[64] Fitzgerald and Halliday, Inc., testimony, March 12, 2002 in Siting Council Docket 217.

[65] EMF refers to both the electric and magnetic components of the field. Electric fields exist whenever voltage is present regardless of current, and have little ability to penetrate buildings or skin. Magnetic fields exist only when current is flowing in any medium that is not magnetically permeable, such as air or soil, but not in media that are magnetically permeable, such as iron. It is generally assumed that any health effect from exposure to EMF would be due to the magnetic component of the field, or to electric fields and currents that these magnetic fields induce in the body.

from the California Department of Health Services were asked to review the scientific literature that was also reviewed by scientists convened by the National Institute of Environmental Health Sciences. The California scientists were more inclined to believe that EMF exposure increased the risk of health problems than the majority of the scientists on the National Institute of Environmental Health Sciences committees.[66] In June 1999, after six years of research, the National Institute of Environmental Health Sciences concluded that the evidence for a risk of cancer and other human disease from EMF around power lines is "weak."[67] Although research still continues into the health effects of power lines, "to date the scientific evidence is inconclusive, and a direct link between adverse health and EMF associated with electric power frequency of 60 Hertz cannot be confirmed or denied."[68]

Although several states such as New York and Florida have established EMF standards, there are no federal standards for EMF for protection of human health. In Connecticut, the Siting Council has taken a conservative approach and adopted best management practices for minimizing EMF and exposure to EMF around electric transmission lines. These practices require EMF assessments of each proposed project and alternatives, consider low-EMF designs, and require extensive pre- and post-construction monitoring.

EMF produced by overhead and underground lines exhibit key differences. Whereas there are no electric fields at ground level from underground cables, overhead lines will produce an electric field in the ROW, but that field can be reduced to some extent by trees, buildings, and other physical objects. Overhead lines are at least 30 feet or more from the ground level, whereas underground cables are generally buried no more than 4 feet. Thus, beyond the edge of the ROW, magnetic fields from underground cables are weaker than from overhead lines.

EMF management options for overhead lines include decreasing the current (magnetic field) or voltage (electric field); increasing the distance between ground level and the conductors; and arranging the geometric configuration of the conductors so that the EMF produced by each one tends to cancel. Vertical and "delta" (triangular) arrangement of the conductors result in a greater degree of phase cancellation and EMF reduction than horizontal arrangements.

<u>Construction Impacts</u> – Constructing or widening ROWs and installing tower footings requires removal of vegetation, soil excavation, and possible blasting to remove ledge, and causes disturbance to the soil structure. Temporary impacts include increased erosion and potential increased runoff of sediment into wetlands and water bodies with concomitant water quality impacts. Constructing transmission lines in open country also involves construction of temporary or permanent access roads. Such road construction may also be associated with increased erosion and sedimentation, impact to wetlands and

[66] Report 7 of the Council on Scientific Affairs (I-94), "Effects of Electric and Magnetic Fields," http://www.ama-assn.org/ama/pub/article/2036-2499.html.
[67] California EMF Risk Evaluation, June 2002.
[68] Acres International, July 1996, *Life Cycle Cost Studies for Overhead and Underground Electric Transmission Lines*.

watercourses, damage to vegetation and habitat alteration. Topographical changes due to construction may block amphibian migration routes around vernal pools and affect breeding populations.

Traffic impacts and construction noise may impose some limitation on construction activities. Some municipalities have ordinances that regulate allowable construction hours. Construction in or across a street may be restricted during morning or evening rush hours. Clearing and construction may be restricted at different times of the year at locations with sensitive wildlife habitat, limiting construction activities around breeding periods. Fugitive dust raised by construction vehicles moving along the ROW can be minimized by spraying water. D&M Plans generally require best practices for controlling runoff, mitigating construction impacts, and restoring impacted areas.

<u>Other Impacts</u> – Overhead lines have the following additional impacts:

- ROWs may decrease land available for recreation, but may also attract unauthorized recreational vehicle use.
- ROWs placed in agricultural areas may decrease the productive land available.
- Buried archaeological resources are unlikely to be affected, except where there is ground disturbance.
- Visual impacts and health concerns may have an adverse effect on real estate values, and on municipal tax revenues as a secondary effect.
- Noise is produced from overhead transmission wires during certain weather conditions (audible corona discharge); noise is unlikely to occur with 115 kV or lower voltage facilities.[69]

2.9.3 Underground Electric Transmission

Connecticut has over 50 miles of 69 kV, 115 kV, and 138 kV underground high voltage transmission lines. The heating caused by line resistance becomes an important design constraint for underground cables, whereas overhead lines can dissipate heat more readily. A pre-construction soil thermal survey can determine whether special backfill is necessary to adequately dissipate heat away from the line. Underground cables also have much higher charging currents than overhead lines, which for longer length and higher voltages require shunt reactors to compensate. The number and placement of shunt reactors is a function of the electric system, and the capacitance of the underground cable. Primary functions are cable design voltage, type of insulation (paper or XLPE), and length of cable.

[69] Acres International, July 1996, *Life Cycle Cost Studies for Overhead and Underground Electric Transmission Lines*.

Cable Technologies – Commercial installations of HVAC underground lines rely on three main technologies: HPFF, XLPE, and self-contained fluid filled (SCFF). HPFF is the most prevalent in the U.S. and consists of an outer steel pipe housing, paper-insulated cable, and dielectric insulating fluid similar to mineral oil. HPFF systems require monitoring for pressure and leak detection, as well as a cathodic protection system to maintain integrity of the pipe enclosure. Consolidated Edison Company of New York has a very extensive 345 kV HPFF underground cable transmission system in the New York City area. This HPFF cable system dates to the mid 1960s and the longest cable circuit is approximately 18 miles. Shunt reactors are installed at the terminals of the circuit and phase shifting transformers are employed extensively to control power flows on the underground transmission systems. In Boston, NStar operates approximately 40 miles of underground 345 kV HPFF cables.

SCFF cable, like HPFF, is a paper-insulated cable. The conductors are hollow and filled with pressurized insulating fluid; the fluid-filled conductors are wrapped in high-quality kraft paper and protected by a metal sheath and a plastic jacket. SCFF technology is common in direct buried and submarine installations.

The developing alternative technology is solid dielectric cable that utilizes insulating material around the conductor, which is extruded cross-linked polyethylene (XLPE) technology and does not require dielectric fluid. The benefit of this design is the elimination of the ancillary system and risks associated with the dielectric fluid. To date, utilities have preferred solid dielectric cable for underground installations up to 138 kV. There are currently two 230 kV XLPE cables and plans for several additional installations in California, Washington, and Colorado.

Although there is only about 1 mile of 345 kV underground XLPE cable in service in the U.S., approximately 150 miles of XLPE cable at 345 kV and higher have been installed overseas since 1995 with varied success. Joint reliability, cable manufacturing quality control, and thermomechanical forces present reliability issues for XLPE systems at these voltages. Two 400 kV direct buried cables, 21 km (13 mi)[70] and 12 km (7 mi) long, were installed in Copenhagen in 1997 and 1999 with a good service record. In Berlin, there are two 6 km (4 mi) 400 kV XLPE cables which were built in 1998.[71] In the United Kingdom, there are three 400 kV underground XLPE lines totaling over 14 miles.[72] There are a number of high voltage underground XLPE cable projects in Asia according to Sumitomo Electric, a major supplier of XLPE cables. Sumitomo has supplied 23 underground XLPE lines over 200 kV in Japan, totaling over 275 miles. Overall, there are 22 underground 500 kV XLPE lines in Japan totaling over 60 miles;[73] one of these recently experienced a 7-month outage. China and Hong Kong have seven underground XLPE lines over 200 kV, totaling more than 45 miles.

[70] Consists of two segments, 12 km and 9 km, separated by the site of a future generating facility.
[71] Walter Zenger, Technical Lead, Electric Power Research Institute Presentation to Working Group, September 10, 2002
[72] Worldwide EHV Experience List, Electric Power Research Institute, November, 2002
[73] Ibid.

Availability versus Reliability of Underground Cables – The availability/reliability aspects for an overhead and underground cable system are sometimes confused. Reliability can be measured in terms of the frequency of line failures. Availability can be measured in terms of overall power capacity, including failure and repair periods. Underground cables are less susceptible to damage due to *force majeure* events. However, a single-cable underground circuit has *less availability* than an overhead line because a fault requires much longer to locate and to repair. This shortcoming can be addressed with a dual-cable underground circuit in which the second circuit continues to transmit power even when the first circuit is in repair. Thus, a dual circuit underground cable may have availability and reliability advantages compared to a single overhead line. Complicating the picture, this availability advantage is offset to some degree, because an overhead line actually has a much higher-than-listed capacity for short periods of time than dual cable underground circuits, which allows for overloading during peak periods or contingency events. Furthermore, underground splices are necessary for underground installation, which is considered by industry experts to reduce reliability of cables approximately 350 kV and higher. The distance between splices is a function of the thickness of the cable and capacity of the cable spool. Notwithstanding these distinctions, design specifications for either overhead or underground cables can meet the industry reliability standard of one event in 10 year LOLE.

2.9.4 Environmental Impacts of Underground Electric Transmission Lines

The environmental impacts of underground transmission lines can vary widely based on the pathway chosen. Underground installations that traverse an otherwise undeveloped landscape have the greatest impact to natural resources, greater in many instances than an overhead line in the same path. Conversely, an underground installation that primarily follows existing public roadways will have the least impact on natural resources.

Vegetation and Wildlife Impacts – As with overhead transmission lines, clearing vegetation for underground lines outside of a public roadway may result in a change of wildlife habitat, creation of edge habitat, and potential for introduction of invasive species. While the width of the ROW may be substantially less than that for an overhead transmission line, trees and shrubs must be fully cleared from an underground line. This is because the roots attract water from the soil around the line and reduce the soil's ability to transfer heat away from the line. The limitation on vegetation may make the value of the ROW as wildlife habitat, as compared to ROWs for overhead lines, substantially less. In the case where the line follows an existing public roadway or railroad track, the loss of habitat would be negligible.

Underground transmission lines installed in the existing public roadways take advantage of a previously disturbed corridor and thus have negligible impacts to vegetation and wildlife as compared to a cross-country overhead installation. The construction activities will require a 30+ foot wide swath, which would be wholly or partially satisfied by the roadway itself and its shoulder. Impacts likely to occur would include minor to substantial removal of roadside vegetation. While this may alter the character of the roadway, there will be minimal if any impact to the wildlife support capacity of the road shoulder. The composition of the wildlife community in developed areas already experienced the shift in species that are intolerant of development to species that are development tolerant when the road and surrounding structures were constructed in the past.

Wetlands and Water Resources – Because continuous trenching is required, impacts on wetlands may be greater for underground lines outside of public roadways than for overhead lines. Installation of underground cable requires disturbance of the soil profile that is important in maintaining wetland vegetation. Special care must be taken to restore appropriate soils, maintain wetland hydrology, and reestablish wetland vegetation to restore wetland habitat and function. This may require monitoring over several growing seasons. Runoff of herbicides, if applied, may contribute to water pollution.

Transmission lines that are buried along public roadways are likely to encounter watercourses and wetlands. To minimize impacts to watercourses, the transmission lines may be mounted to existing bridges or directional drilling may be used to trench below the watercourse. Impacts to wetlands will vary depending on the proximity, size, and functional integrity of the wetland and installation factors such as the ability to move the trench into the road rather than the shoulder, extent of grading and clearing needed, and the ability to place spliceboxes away from wetlands. Regardless of the value of the wetland and installation requirements, it is likely the wetland sustained some impact from the original road crossing. The addition of a transmission line trench may increase the degradation somewhat or have no further impact at all.

Visual Impacts – The visual impacts of underground lines outside of and within public roadways are substantially less than overhead lines due to absence of above ground structures and substantially narrower corridors. Underground transmission lines placed in existing developed road corridors would not detract from the existing viewshed. There would be impacts due to loss of road-side vegetation, potentially including notable old trees. These impacts would be greatest along more rural or residential streets as compared to roadways in commercial areas.

Health Effects – As discussed above, because soil (and especially wet and/or clay-rich soil) is a relatively good electric conductor, there are no electric fields at ground level from underground cables.

Best management practices for reducing EMF from underground lines include reducing the current, increasing voltage, increasing burial depth, and utilizing conductor configurations that minimize the resulting magnetic field. Underground lines that are insulated with XLPE or dielectric fluid can be placed closer together than overhead lines, increasing the phase cancellation effect. Enclosing a cable in a metallic pipe can attenuate the magnetic field by inducing counter currents. However, this approach can increase line losses, and the line must be designed accordingly to minimize such losses.

Insulating Fluid Leaks – HPFF and SCFF cables most commonly utilize a non-toxic insulating fluid that can be released to the environment from underground cables through leaks in pipe joints, from corrosion, or by accidental damage to the cable system. The two most common types of dielectric fluid are alkylbenzene and polybutene. Although they are non-toxic, they are slow to degrade in the environment. Released to the environment, the fluid can migrate downward through the soil or may preferentially follow a migration path along the pipe backfill material and along intersecting utilities. Depending on the volume of fluid released, the soil properties, and the depth to groundwater, the fluid may reach the groundwater and accumulate as a lens or plume floating on the water table, potentially impacting nearby wells. Fluid reaching storm sewers or other conduits may discharge to waterways and degrade surface water quality. Spills of insulating fluid to soil, sediment, surface water, or ground water are subject to the same state and federal regulatory clean-up requirements as any release to the environment.

Concerns associated with use of dielectric fluid are minimized through improved pipe materials and leak-detection technologies. Real-time sensors can detect small leaks, on the order of 0.1 gallon per hour.[74] However, it should be noted that a pipe failure or puncture can result in the release of a significant volume of fluid over a short period of time. Both HPFF and SCFF cables must have a spill control plan.

Construction Impacts – Although a narrower ROW is required for an underground line, either within or outside of a public roadway, than for an overhead line, land clearing and excavation can result in short-term impacts including increased runoff, sedimentation, and water quality impacts. These impacts can be wholly or partially mitigated through best management practices for erosion control. The installation of an underground line outside of a public roadway may have greater impacts than an underground line within a public roadway, and may have similar or greater ecological impacts as an overhead line. Construction on existing public roadways and in developed areas will give rise to temporary traffic impacts and nuisance issues of noise and dust. State and local permits and easements will require suitable safety measures, dust suppression, and hours of operation.

Other Impacts – The excavation necessary for underground transmission line construction may require an archeological survey in advance of construction or monitoring of the excavation during construction. Excavation through areas of contaminated soils or hazardous waste requires special soil management procedures and DEP involvement.

2.9.5 HVDC Transmission Technology

HVDC has been predominantly used for long-distance transmission, because it has advantages over AC cables in efficiency and power loss. Although the majority of

[74] John Engelhardt, President, Underground Systems, Inc., 9/10/2002

HVDC systems are overhead,[75] HVDC cable technology is available for underground and underwater applications as well. HVDC is currently attractive in merchant transmission applications because of its ability to control the direction and magnitude of power flow, which allows the power flows to be limited to those of paying customers. Although the line cost per mile may be less than for AC lines, each terminus of a HVDC cable requires a large converter station to connect with the AC grid. Therefore, it is usually more expensive to build a HVDC than an AC circuit, and it is significantly more expensive to add an intermediate delivery point on a HVDC line than on an AC line.

There are three main types of underground HVDC cable technologies:

- Mass-impregnated, non-draining paper insulated (MIND) – historically most common HVDC cable.

- Low pressure, self-contained fluid-filled (SCFF) – limited in length due to fluid pressure constraints.

- Triple extruded polymeric (HVDC Light) – lighter and smaller than MIND cable, uses no oil, with capacity up to 150 kV to date. However, XLPE cable cannot be used with conventional DC technology; it is limited to HVDC circuits, which utilize transmission rather than diode technology.

TransEnergie, a subsidiary of Hydro-Quebec, has been on the forefront of HVDC cable development internationally. TransEnergie Australia's DirectLink project, a 60 km (37 mile) underground 180 MW HVDC project connecting New South Wales and Queensland, has been operational since 2000. The recently completed Murraylink Project connects Victoria and South Australia with a 220 MW / 150 kV underground cable interconnection that is 176 km (110 mile) long. Horizontal drilling was utilized to install the cable under the Murray River, road and rail crossings, and significant Aboriginal heritage sites. In the U.S., Transenergie's TE-CSC Project is a submarine application of HVDC cable, utilizing a specialized cable with steel armor on the outside and flexible XLPE insulation around a copper conductor.

2.9.6 Developing Technologies

Recent advances in super-conducting technologies have enabled the development of "high" temperature superconducting (HTS) low voltage cables. HTS cable consists of a ceramic-based conducting material, bathed in liquid nitrogen, and wrapped in thermal and electrical insulation. In principal, superconductor cables have several advantages over conventional aluminum or copper cables:

[75] Of 157,800 miles of transmission lines in the U.S., 3,300 miles carries DC current. (DOE, 2002 National Electric Transmission Grid Study.)

- The capacity of HTS is up to 140 times that of copper cables. Replacing conventional conductors with HTS can upgrade capacity without increasing the voltage or ROW width.
- Excluding the cooling equipment, HTS cables do not emit heat to the environment.
- Power losses through HTS are much lower.

HTS cable is still in development, and production costs for the HTS wire are not yet in the commercially feasible range. Several demonstration projects show promise. A 30 kV/104 MVA project at a substation in Copenhagen in 2001 was the first HTS utility demonstration project. The 24 kV/100 MVA project at a Detroit Edison substation will be the first underground project and the first demonstration project in the U.S. However, this project is experiencing start-up difficulties.

2.9.7 Regional Environmental Impacts of Transmission Infrastructure

Regional Air Quality Impacts – Emissions from electric generation facilities are widely recognized as having a direct impact on the state's air quality. Nationwide, fossil fuel-fired generators contribute 63% of the SO_2, 22% of NO_x, and 37% of the anthropogenic mercury to the environment.[76] The National Ambient Air Quality Standards (NAAQS), promulgated by the EPA, establish health-based targets for criterion air pollutants in the U.S. Most of SWCT is classified as a severe non-attainment area for ozone, and the remainder of the state is a serious non-attainment area for ozone.[77] Ozone is formed in the atmosphere through chemical reactions involving precursor pollutants, NO_x[78] and volatile organic compounds. The entire state of Connecticut is also designated as a maintenance area for carbon monoxide (CO), and New Haven is a moderate non-attainment area with respect to fine particulate matter (PM_{10}). Consequently, new sources of non-attainment criterion pollutants in Connecticut are subject to stricter federal and state emissions limits and emissions controls than new sources in attainment areas. DEP regulations promulgated or revised in the last few years[79] phase in reductions of NO_x and SO_2 emissions from existing large fossil fuel fired power plants. The regulations represent significant annual emission reductions of NO_x and SO_2 from sources in Connecticut.

Atmospheric pollution transport plays a major role in determining air quality in the northeast. NESCAUM has observed that on the worst air quality days in New England,

[76] NESCAUM, Presentation to the Working Group and Task Force, November 6, 2002.

[77] Where sufficient data exist, the EPA has classified areas of the U.S. as either attainment or non-attainment with respect to the NAAQS. The degrees of non-attainment for ozone are submarginal, marginal, moderate, serious, severe, and extreme, with several sub-classifications. The towns of Bridgewater and New Milford in Litchfield County, plus all of Fairfield County, except the City of Shelton, are severe non-attainment areas for ozone.

[78] Includes several oxides of nitrogen, collectively referred to as NO_x.

[79] R.C.S.A. Sec. 22a-174-19a and Sec. 22a-174-22.

prevailing winds transport air pollutants to New England from the mid-Atlantic and mid-west states. Thus, Connecticut's air pollution is due in part to indigenous sources, and in part due to upwind industrial and fossil-fueled electric generation sources.

If electric transmission expansion projects relieve transmission constraints, the order in which generation units are dispatched will be altered. Transmission expansion may facilitate the dispatch of formerly locked-in clean generation, such as new and efficient gas turbines, and thereby displace older and more polluting oil or coal generation. In this situation, there would be a net decrease in the emissions of SO_2, NO_x, mercury, and carbon dioxide. Alternatively, if electric transmission expansion allows low-cost, but more polluting fossil generation sources to be dispatched more hours per year relative to cleaner generation, net emissions will increase.

Expanded natural gas transmission capacity also promotes the development of clean gas-fired generation that can displace less efficient or more polluting fossil fuel fired power plants. Because the prevailing air transport direction is generally toward the northeast, Connecticut's air quality may be affected to some degree by changes in fuel type and generation dispatch in upwind states.

ISO-NE has quantified some of these impacts on a regional basis. The RTEP02 Report included an analysis of fossil fueled plant air emissions under ten different transmission scenarios. The analysis provides a five-year forecast of total SO_2, NO_x, and carbon dioxide emissions for New England that incorporates the emission reductions mandated in accordance with recent Connecticut and Massachusetts air quality regulations. The study concluded that new transmission projects have a marginal effect on total New England emissions from power plants in the six states. However, state-by-state results were not provided, and the net impact to Connecticut due to transmission infrastructure expansion within the state and upwind was not specifically analyzed.

Currently, ISO-NE is also investigating the impact of its demand side management programs on New England power plant emissions. ISO-NE expects to report these results in RTEP03. On an annual basis, the NEPOOL Environmental Planning Committee calculates the region-wide marginal emission rates for SO_2, NO_x, and carbon dioxide, expressed as pounds of pollutant per MWh and as pounds of pollutant per MMBtu. The marginal emission rate represents the average emission rate of the marginal 500 MW of generation averaged over the year.[80] In general, the annual average marginal emission rate for NO_x shows a downward trend from 1993 to 2000 for the entire New England region. These analyses presumably will be utilized to assess the avoided emissions for a known or projected quantity of demand side reductions. To the extent that on-site emergency generation or other DG having higher emission rates is used to replace bulk power supplies, emissions from such sources may be offsetting and may, in fact, increase net emissions.

[80] In addition to the annual average, the study examines four specific sets of hours: on-peak ozone season (May to September, inclusive), off-peak ozone season, on-peak non-ozone season, and off-peak non-ozone season.

2.10 LONG ISLAND SOUND INFRASTRUCTURE TECHNOLOGY

This section provides a preliminary overview of submarine construction technologies applicable or potentially applicable to Long Island Sound crossings. The Task Force continues to evaluate the environmental impacts of these technologies.

2.10.1 Marine Construction Methods

Submarine pipeline, electric cable, and telecommunication cable projects utilize a variety of construction methods. It is not uncommon for pipeline and cable projects in marine environments to use different construction methods for different line segments. The selection of a particular method is dependent on a number of factors, including biological communities and habitat, sediment characteristics, depth to bedrock, distance from shore, and water depth. With some modification these construction methods can be used for either pipeline or cable installations.

<u>Horizontal Directional Drilling</u> – HDD is typically employed in near-shore environments to minimize disturbance of the overlying bottom materials that would normally occur with conventional open-cut technology. It can be used for both pipeline and cable installation. The desire for negligible sediment disturbance within shallow areas strongly favors the use of HDD. Because it is a trenchless process, there is minimal direct disturbance of benthic communities as well as minimal indirect disturbance from resettling sediment. The equipment and techniques used in this method are derived from well drilling technology and allow the pipeline, or the conduit in the case of cable installation, to be installed beneath obstacles or sensitive areas.

The drill rig is typically staged and operated from the landfall area, where the entry pit is established. The drilling process is completed in a series of steps, including pilot drilling, reaming, swabbing, and conduit installation. The leading edge of each step is guided by an electronic positioning system.

Bentonite, a non-toxic drilling fluid, is delivered to the cutting head to provide hydraulic cutting action, lubricate the drill bit, stabilize the hole, and remove cutting spoils as the drilling fluid returns to the entry point of the pilot hole. Typically, bentonite clay returns are processed to remove the cuttings, and the bentonite fluid is recycled for use as the drilling operation continues. Some bentonite typically leaks from the HDD exit point. Because the drilling fluid is denser than water, it tends to remain near the seafloor, and can be recaptured at the exit hole. However, if the bentonite, under pressure, encounters a weakness in the soil or bedrock, it may "frac-out" and cause an uncontrolled discharge to the seafloor.

Feasibility of the HDD technique for a specific crossing location is a function of the subsurface geologic conditions, pipe diameter, and entry and exit conditions. Installations through profiles with diverse geologic strata are difficult and may require re-tooling the drilling and reaming heads to accommodate the varying formations. Installation through rock formations is possible, but difficult. The presence of gravel lenses, cobble, or boulders within the profile strata represents the most adverse geologic condition, and the HDD technique is typically not a feasible alternative in this type of strata. Current technology can achieve directionally drilled installations of approximately 2,000 feet for cable installations and up to 4,000 feet for pipeline installations. Unlike pipelines, the tensile strength of the cable limits the length that can be pulled through a conduit.

Dredging – Dredging is used primarily for trenching along the shallow water portions of a pipeline or cable installation. Barges, equipped with a crane and a clamshell bucket are used to excavate a trench to the appropriate depth. Barges may also support a hydraulic excavator. Excavated material may be transported to a disposal site or side-cast along the trench depending on quality of the sediments and nature of the bottom environment. Barges are typically positioned by three spuds, large columns that are sunk into the bottom to anchor the barge, with one spud, a walk away spud, to allow some movement in the direction of the trenching. Once the pipe or cable has been installed and tested, the dredge barges backfill the trenches. If depths allow, a drag bar may be used to attempt to level out the cover over the trench.

Shoreline Trenching – Shoreline trenching may be used in the transitional zone where upland trenching meets the jetted or plowed portion of the trench. For electric cables, jetting equipment is available which reaches up to the high tide line, provided that the tender with the pumps can get close to shore. In such a case, shoreline trenching can be minimized. However, shorelines which are exposed to substantial wave action can be very resistant or coarse-grained, such that jetting or plowing is not feasible. In such cases a conventional trench is simply extended from the upland past the shoreline until the point where the sediment is sufficiently fine-grained to enable the jet or plow to operate.

Deep Water Trenching – Deep water construction typically uses two barges sequentially: the lay barge and the bury barge. For a pipeline installation, the lay barge has on-board facilities to weld the pipe sections together and lower them to the sea floor. The bury barge, equipped with a jet or plow, excavates a trench under the pipeline or cable and buries the line to complete the installation. Alternatively, the lay barge may perform both functions. The deepwater barges are typically several hundred feet long, and positioned with 8 to 12 anchors that are handled by anchor tugs. The barges may be supported by a number of other craft such as pipe barges, dive support boat, and transport vessels.

Jetting – The jetting method of trenching uses high-pressure water or air jets to excavate the trench and bury the pipeline or cable. Excavated materials are discharged away from the pipeline or cable and the pipeline or cable gradually settles into the trench created behind the jet sled. Minimum jet pressure varies with different seabed materials. A depth of burial of 3 to 6 feet or more typically can be attained with one pass of the jet sled. Greater trench depths typically require multiple jetting passes. Backfilling of the trench is generally accomplished by natural erosion (slumping) of the trench walls due to tidal and ocean current forces, or by subsequent siltation by suspended sediments, particularly during storm events. If natural sedimentation processes do not fully backfill the trench, it may remain partially open. Some jetting equipment can be operated remotely from ships.

This equipment is self-positioning thereby eliminating the need for anchors or spuds.

Plowing – Under this method, a plow is moved by barge along with the pipe or cable. The plow is designed to cut a ditch approximately 8 feet deep and 6 to 8 feet wide in front of the cable or pipeline. Sidecast spoils accumulate on either side of the trench. The weight of line causes it to descend into the open ditch behind the plow. Backfilling is generally accomplished through natural siltation and sediment transport processes.

Hand Jetting – A diver-operated hand jet may be used to bury the cable or pipeline. Hand jetting is typically used for distances of less than several hundred feet, including where HDD-installed pipeline is connected to conventionally installed line, at tie-in pipeline welds, and at lateral side taps. For hand jetting, a support vessel provides pressurized water through a hose and nozzle maneuvered by a diver. The diver works the sediment from under the cable or pipe to create a trench into which the cable or pipe settles.

Surface Lay – For certain applications, the pipeline or cable is laid on the sea floor and covered with an armoring of stone rip-rap or concrete mats. This method may be employed where a line must cross bedrock, other cables or pipelines, or contaminated sediment where disturbance is undesirable. Typically this method is only utilized for short distances.

Blasting – Blasting may be required where the trench encounters resistant bedrock.

2.10.2 Environmental Impacts of Marine Infrastructure

Existing research on the geology, water quality, and ecology of Long Island Sound[81] provides some basis for understanding the actual and potential environmental impacts of energy infrastructure projects. Sound-wide habitat characterizations and a fuller understanding of near-shore conditions need to be more fully developed, and further research is needed. Site-specific and project-specific information has been derived from a number of sources, including but not limited to:

- Periodic sidescan sonar and cathodic protection surveys conducted by Iroquois between Milford and Northport[82] and sidescan sonar and other marine surveys[83] conducted by NU between Norwalk and Northport. Intended to check the integrity of the structure, these surveys are limited to information on the extent of trench infilling, seabed erosion and other physical features.

[81] For example: *Journal of Coastal Research*, Special Issue No. 11, Fall 1991, Quaternary Geology of Long Island Sound and Adjacent Coastal Areas; and *Journal of Coastal Research*, Volume 16, No. 3, Summer 2000, Thematic Section on Long Island Sound.

[82] For example, Iroquois Gas Transmission System, L.P., completed a survey of its Long Island Sound crossing in 1999, and compared the pipe burial depths with a 1993 survey. Racal NCS, Inc. Jan. 2000.

[83] Hydrographic, geophysical and geotechnical survey of KeySpan/Northeast Utilities interconnect Northport, New York to Norwalk, Connecticut. OSI, Inc. 2001.

- Environmental impact statements prepared by FERC as part of the agency's review of proposed Long Island Sound pipeline crossings[84] These studies are based on an understanding of the marine communities and habitats along the project corridor and the expected or potential response of organisms to the anticipated disturbance.

- Observations by the Connecticut Department of Agriculture, Bureau of Aquaculture, and from commercial fisherman who operate in the vicinity of the Iroquois pipeline, the TE-CSC, and other existing submarine structures.

- General information on the persistence of old marine borrow pits, dredge disposal sites, and other bathymetric features. This information contributes to an understanding of sediment transport mechanisms on the seabed and how seabed scars from construction may be expected to heal.

- Historic and recent releases of dielectric fluid as a consequence of damage to CL&P's and LIPA's 138 kV line 1385 submarine cables. In responding to these incidents, the utility and state agencies have observed the migration, dispersal, and impact of the fluid in the marine environment.

Despite this growing body of information, empirical data on the long-term impacts on marine habitats and communities is limited. The TE-CSC was the first cross-Sound energy transmission project that was required to conduct comprehensive pre- and post-construction monitoring. Prior projects, such as CL&P's and LIPA's line 1385 and the Iroquois pipeline were not required to implement long-term monitoring plans. Periodic survey information obtained along these lines is useful but may not be directly relevant to new projects using current construction technologies. Furthermore, it is often difficult, based on the information available, to conclusively find a causal link between a specific project and an observed impact to habitat diversity, species population, or other ecological parameter. Projects that have been undertaken recently, for example, the TE-CSC and the Hubline pipeline projects, are anticipated to expand the knowledge base with respect to long-term and short-term environmental impacts. As required under PA 02-95, the Long Island Sound Task Force Comprehensive Assessment and Report-Part II will include an evaluation of the individual and cumulative environmental impacts of proposed and existing infrastructure crossings. For purposes of this report, the following discussion is intended only to provide a summary of potential environmental impacts associated with the various submarine construction methods.

All trenching methods, including dredging, plowing, and jetting, cause a direct impact to bottom sediments and fauna through excavation, placement or sidecast of spoils, and backfilling. Anchors and spuds used in positioning the trenching and lay barges and the HDD support vessels also directly disturb bottom sediments. In the span between the anchor points, the sea floor may be disturbed by cable sweep as the anchors are moved. The impact corridor for each construction method is summarized in Table 13. The width

[84] For example, Islander East Pipeline Project, Final Environmental Impact Statement, Docket No. CP01-384-000, August 2002.

of the burial corridor for plowing, jetting, and dredging includes the trench and the sidecast spoils.

Water quality is directly affected from the displacement and disturbance of bottom sediments and the resultant release of sediments into the water column causing increased turbidity. The suspension of sediments into the water column can temporarily affect water quality through the reduction of dissolved oxygen and depth of light penetration, as well as potentially by the release of contaminants. The plume of turbid water drifts with the water currents and eventually settles on the bottom. The plume's duration and extent of migration depend on many site-specific variables, including the original size of the plume, the size of sediment particles, water depth and temperature, current velocity and tidal stage, and wind direction and speed. Coarse sediments generally settle quickly, and finer sediments remain suspended in a plume for longer periods of time. Because jetting fluidizes bottom sediments, the jetting technique may cause greater disturbance to sediments and also may disperse sediments over a larger volume of the water column than the subsea plow, which pushes sediments aside. Some remotely operated jets, such as the SmartJet utilized for the TE-CSC project, use a self-positioning ship, which avoids the use of anchors or spuds.

Table 13 – Required Widths for Pipeline Construction Activities[85]

Activity	Required Width (ft)
Plow Burial	75
Jet Burial	100 – 300
Dredging	150 – 200
Blasting	Varies
Offshore Lay Barge Anchoring	2,000 – 4,000
Shallow Lay Barge Anchoring	200 (Spud) to 2,000
HDD Support Mooring: Jackup	200 – 300 (Jackup Pads)
Spud Mooring	75 – 200

Benthic communities and fisheries resources may be potentially impacted by direct disturbance of bottom sediments from trenching, barge anchoring and cable sweep, and by acoustic shock from bedrock blasting. Indirectly, these organisms may be impacted by the associated turbidity and sediment deposition, and by subsequent erosion of the trench spoil mounds. Potential direct significant adverse impacts in the construction corridor include mortality by dislodgement or burial, and disturbance and destruction of commercial shellfish resources. Potential indirect, significant, adverse impacts include mortality by suffocation beneath silt, interruption of spawning and migration, habitat loss or alteration, and introduction of water pollutants and non-native species.

A primary concern is to shellfish beds and fisheries resources and habitats in the nearshore and shallow marine environment. The Bureau of Aquaculture reports that

[85] Reported by Duke Energy Gas Transmission and Iroquois in a joint presentation to the Task Force on November 13, 2002.

shellfish beds in the nearshore area of the Iroquois pipeline, constructed in 1990, remain unproductive. Recovery of the bottom habitat and shellfish resources depends on a number of factors, including depth of the scar or disturbance, the local sediment transport regime and most importantly on the original nature of the benthic environment. For example, if anchor scars or trenches do not refill by natural sedimentation, they might persist as depressions, accumulate fine-grained materials and organics, and develop different benthic communities. This would represent a long-term conversion of shellfish habitat.

The release of HDD drilling fluids has the potential to impact water quality and marine life through increased turbidity and sedimentation. The fluid consists of a slurry made from a naturally-occurring bentonite clay.[86] This very fine-grained material can suffocate benthic organisms and alter the seafloor habitat. During the HDD process, efforts are made to contain and recover much of the bentonite drilling fluid. However, there is a potential for inadvertent release of drilling fluid along portions of the drilled segment where a bedrock fracture or weak overlying sediment is encountered. The DEP currently requires all permit-holders in Long Island Sound who utilize HDD to post an environmental performance bond to guarantee cleanup, in the event of an uncontrolled release of bentonite fluid. In addition, applicants are required to prepare and implement a detailed monitoring plan to minimize the possibility of a release.

2.11 CONSERVATION AND LOAD MANAGEMENT

Utilities and state regulatory commissions began to focus on C&LM (also known as demand-side management) in the 1970s as a meaningful complement to supply-side planning and bulk power system construction. As nuclear power plants in various stages of development around the U.S. were cancelled, many utilities in New England implemented aggressive C&LM programs in conjunction with federally-mandated cogeneration and renewable technology programs.

Over the last two decades there has been significant utility, regulatory, and public interest in C&LM. State public utility commissions required investor-owned utilities to develop and fund large-scale initiatives to commercialize and deploy energy-efficient technologies. Advancements in information and metering technology accelerated the ability to gauge and measure C&LM as a resource. Program design and implementation were also improved upon, increasing the economies of scale and scope of program delivery.

In the mid-1990s, a combination of factors led to reduced interest and investment in C&LM, in particular, the changing role of electric utilities, soft energy prices, and the high incremental cost to support increased market penetration. As utilities exited the traditional merchant function associated with delivering the electric commodity, many C&LM initiatives became increasingly marginalized. Although funding targets for

[86] Some drilling fluid formulations include additives such as biopolymers for lubrication and other properties.

C&LM activities were preserved in many states, the urgency and public interest in aggressive demand-side activities appeared to wane in response to the stable or declining energy prices and the new incentives surrounding the competitive retail market.

Lately, high and volatile commodity prices have renewed interest in C&LM. In some instances, C&LM can be seen as a potential alternative to transmission expansions. Participation in C&LM programs will be dependent on relative price levels, price volatility, price elasticity, capital investment, customer choice and preferences, and customer load profiles. A review of C&LM technologies and programs in the region and in Connecticut follows.

2.11.1 Technology Innovations

C&LM technologies range from simple, inexpensive residential measures to complex, capital-intensive projects for large industrial plants. These technologies include high efficiency florescent bulbs and improved lighting technologies for commercial buildings, more efficient variable speed motors for manufacturing, more efficient residential appliance standards, reduced thermal losses and better heating, ventilation and air conditioning equipment designs, and improved residential electric heating and cooling systems. Federal funding has been applied to more complex uses of energy in industry. Industry and government laboratories are continually evaluating new technologies and reassessing the cost-effectiveness of measures that were deemed too expensive to implement when first developed.[87] Federal money for energy efficiency endeavors, according to the Industries of the Future program, increased from $65.6 million in the FY 2000 budget to $72.4 million in FY 2001, but declined to a requested $46.4 million in FY 2002. Additional technologies, such as real-time metering, are improving the abilities of LRPs in New England and other regions as ISOs seek alternative means to meet peak loads.

2.11.2 C&LM Programs and Initiatives

C&LM initiatives in Connecticut are primarily implemented via the state's electric utilities, CL&P and UI. The two electric utilities develop their programs with input from the Connecticut Energy Conservation Management Board (ECMB); funding and program design approval is authorized by the DPUC.

[87] Federal research and development laboratories working on energy efficiency include, but are not limited to, Ames, Argonne National Laboratory, Lawrence Livermore National Laboratory, Idaho National Engineering Laboratory, Lawrence Berkeley Laboratory, Los Alamos National Laboratory, National Renewable Energy Laboratory, Oak Ridge National Laboratory, Pacific Northwest Laboratory, and Sandia National Laboratory.

CL&P offers a wide variety of C&LM programs aimed at the residential sector[88] and for commercial, industrial, government, and institutional entities.[89] UI offers a similar slate of programs, targeted towards all primary customer sectors.

In May 2002, the DPUC approved an $86.5 million budget in Docket No. 02-01-22 for DSM initiatives in the state, $69.5 million for CL&P customers and $17.0 for UI customers. These values are based on the projected investments into the C&LM Fund established by the legislature pursuant to PA 98-28. The C&LM Fund receives an assessment of three mills per kWh on electricity sold to each customer of an investor-owned electric utility. After discussions with the DPUC, UI reassessed their C&LM budget, and focused the implementation of measures in SWCT. The DPUC also required CL&P to alter their program investments, and to apply greater effort and budget dollars towards SWCT initiatives. For example, CL&P was required to increase the incentives for participants in the ISO-NE LRP.

The utilities develop their programs and budget with the advice and assistance of the ECMB, created by the Connecticut Legislature pursuant to Section 33 of PA 98-28. The ECMB, an eleven-member Board made up of representatives from business groups, consumer organizations, environmental groups, government agencies and distribution utilities, provides oversight and recommendations on utilities' C&LM program and budgets before they are submitted to the DPUC. The ECMB monitors energy efficiency and LRPs, with particular emphasis on SWCT.

C&LM initiatives are projected to have large paybacks on the investments made. In 2001, CL&P and UI invested roughly $86 million of ratepayer funds acquired through the C&LM Fund. All programs must be cost-effective with a benefit-cost ratio of at least 1.0. According to an ECMB report of 2001 DSM implementation, the $86 million investment is projected to produce a lifetime savings for customers over of $473 million.[90] More than 400,000 customers participated in 2001, including industrial, commercial, and residential customers. At this time, the potential cumulative savings from all current and previous C&LM sources are forecasted to reduce the 2006 summer peak demand by approximately 700 MW from levels otherwise expected. The most successful C&LM programs in 2001, measured in terms of participation and benefit/cost ratio, were retail lighting, advanced design for new residential, commercial, and industrial construction, energy efficient residential washing machine sales, and custom on-site energy audits for commercial and industrial customers. The programs with the lowest benefit/cost ratios were residential audits, heat pump water heater sales, and

[88] The residential programs include: residential retail lighting; "Smartliving Catalog'; EnergyStar applicances; EnergyStar homes; and low income and residential HVAC.

[89] The non-residential programs include: new construction; customer services; express services; small business energy advantage; RFP for energy efficiency program; operation and maintenance RFP program; and state and municipal buildings program.

[90] Report of the Energy Conservation Management Board Year 2001 as represented by UI in Connecticut's Conservation and Load Management Fund, Year 2001 Accomplishments.

express services targeted to small load commercial and industrial customers for upgrading lighting, motors, and heating/cooling units.

Within the C&LM Fund, a research development and demonstration (RD&D) program was established to identify and manage projects that would advance the development of reliable and efficient use of electricity. RD&D projects seek to deliver sustainable energy savings benefits to Connecticut businesses and residents. RD&D seeks to complement the DSM portfolio of energy-efficient measures for all customers by uncovering new products and services that save energy, benefit the state's environment and economy, and enhance power system reliability. CL&P and UI separately administer their RD&D programs, also referred to as Market Transformation Programs.

The RD&D Program solicits innovative technology or technical service proposals in the categories of Energy Efficiency and Distributed Resources. Energy Efficiency technologies are defined as technologies that offer large electric energy savings whether from one improvement or from a series of smaller ones. Innovative technologies sought for consideration include lighting, energy management/load control, computer/ electronics, refrigeration, water heating, electro-technologies, and space conditioning/ HVAC. Distributed Resource technologies are defined as the combined or individual use of DG, energy storage, and load management on the customer side of the meter with complementary energy efficiency benefit, and to address specific customer reliability and power quality needs. Innovative Distributed Resource technologies sought for consideration include photovoltaic (PV), fuel cells, and distributed resources and fuel cell cost analysis.

2.11.3 SWCT C&LM Activities

The DPUC has indicated its belief that "an increased focus on C&LM activities in SWCT, particularly in the NOR area" should be part of a balanced approach to solve the transmission congestion issues facing the region. In Docket No. 02-01-22, the DPUC approved $5.633 million for CL&P's 2002 load management programs in SWCT.[91] CL&P established a goal of 28.85 MW of local reduction in SWCT. As of November 2002, CL&P was able to enroll only 0.7 MW in the NOR sub-area and 6.88 MW in the remainder of the CL&P's towns in SWCT. The DPUC also approved $660,000 in uncommitted funds for UI to reallocate to the NOR sub-area.

The DPUC expected total conservation program savings of 65.6 MW throughout the state and 36.9 MW in SWCT due to 2001 expenditures (Table 14). Savings values for the 2002 implementation are expected to be slightly higher (67.2 MW) with most of the savings in SWCT (40 to 45 MW). According to the DPUC Investigation in Docket 02-04-12, load management savings were projected to reduce load by an additional 44 MW,

[91] CL&P originally proposed a $2.46 million budget, expected to save roughly 10 MW of peak demand. The DPUC subsequently identified $0.93 million of C&LM funds to be reallocated to SWCT load management and CL&P proposed an additional $2.25 million for such endeavors.

all in SWCT, but there is some overlap between CL&P's and UI's load reduction values and ISO-NE's LRP program, as outlined in Table 14.

Table 14 – Peak Load Reduction from CL&P and UI C&LM Programs[92]

	2002 Peak Load Reduction (MW)	
	State-Wide	**SWCT only**
Energy Efficiency Programs		
Original Program Filing	67	40
Incremental SWCT Initiatives	5	5
Total Energy Efficiency	72	45
Load Response Programs		
C&LP	28	28
UI	12	12
ISO-NE SWCT RFP	4	4
Total Load Response	44	44
Total C&LM	116	89
% of SWCT Peak	*n/a*	*2.7%*

2.11.4 ISO-NE Load Response Program

Recently ISO-NE has assumed additional responsibilities for designing and implementing load management programs.[93] In 2001, ISO-NE began its LRP. In coordination with implementation of SMD, ISO-NE is altering and expanding its LRP initiative.

ISO-NE will implement its currently-proposed version of LRP on March 1, 2003. The program is currently expected to run through December 31, 2004. Several aspects of the program are similar or identical to the current version.[94] The new program offers four primary options for customers:

- The Day-Ahead Demand Response Program requires customers to offer energy reductions of 1 MW minimum into the Day-Ahead energy market. If the curtailment offer clears (*i.e.*, is accepted as part of ISO-NE's *pro forma* dispatch), the Demand Resource will be paid the applicable Day-Ahead zonal price. Differences between the actual and offered curtailment are settled at the Real-Time zonal price. Participants in this program are eligible to qualify as an

[92] DPUC Docket 02-04-12.

[93] The New England Demand Response Initiative (NEDRI) is a new forum for exchanging ideas and mechanisms to implement Load Response Programs in New England. NEDRI, in coordination with ISO-NE, has held several forums and issued various white papers on the advantages of and mechanics necessary to implement LRP.

[94] For details on the current program (ending December 1, 2002), see ISO-NE Load Response Prograsm Manual, May 6, 2002.

Installed Capacity (ICAP) resource, consistent with ICAP rules. Any deviation from the participant-offered load reduction will be charged or credited at the appropriate real-time zonal price.

- The Real-Time Demand Response Program comprises two sub-programs: a 30 minute demand response program and a 2 hour demand response program. Both programs require customers to commit to mandatory energy reductions and make customers eligible for ICAP payments. Customers in both programs receive payment for the actual energy they save. Customers in the 30 minute demand response program may also receive a payment set by the price of operating reserves.

- The Real-Time Price Response Program allows customers to voluntarily reduce energy consumption during certain periods determined by ISO-NE. Customers receive payment for the actual energy they curtail. Energy reductions must be between 100 kW and 5 MW unless otherwise approved by ISO. Customers will be notified when the forecasted hourly zonal price is greater than or equal to $100/MWh. Program participants will receive the higher of the applicable real-time zonal price or $100/MWh for all interrupted consumption. There is no penalty for non-performance.

- The Real-Time Profiled Response Program requires the participating customer to provide a statistically-determined percentage of mandatory response that can be achieved upon the ISO-NE signal. Unlike the other LRP offerings, this program does not require participating customers to install more-expensive interval metering. Customers in the Real-Time Profiled Response Program are eligible to qualify as an ICAP resource.

The current LRP offers only two programs: the Demand Response Program and the Price Response Program. According to ISO-NE, as of November 1, 2002 there were 248 customers signed up for the current LRP providing 195.6 MW of potential load relief: 122.5 MW through the Demand Response Program (also known as the Class 1 Program) and 73.1 MW through the Price Response (or Class 2) Program. ISO-NE has not provided the potential or expected capacity savings for the proposed LRP initiatives.

As part of their C&LM activities, Connecticut's electric utilities include funding for implementation and education to improve participation in ISO-NE's LRP program. Total CL&P load management funding for 2002 is projected at $2.5 million. This includes monies to improve LRP participation for software contractors to support customer enrollment, education initiatives targeted toward SWCT customers, and for the installation of data recorders to establish baseline consumption patterns.

These ratepayer funds include Market Transformation Programs, most of which have potential load management implications with greater research requirements and long-term implementation horizons. One program is a study of emission reduction technologies for diesel generators, which could participate in the ISO-NE LRP, but for air emission restrictions. Another program under the Market Transformation umbrella is the Smart Thermostat program, which allows CL&P to control residential air conditioning loads to moderate peak demand. This pilot program is primarily targeted at SWCT, with 45 of the 50 projected homes in that region.

In its budget authorization process, UI indicated that demand for commercial and industrial projects far exceeds the company's budget. Accordingly, UI developed its Emergency Response Program to prioritize and accelerate the C&I projects already in the queue. The Emergency Response Program employs a matrix to select projects based on their load reduction capabilities, location, projected cost/benefit ratios, and timing.[95] The DPUC authorized $200,000 of UI's C&LM budget to implement the programs that scored highest through the ERP matrix. UI forecasted that its load management activities would enroll 4.9 MW of the ISO-NE Class 1 load and 6.0 MW of Class 2 load out of a total UI peak load of approximately 1,300 MW.

2.12 DISTRIBUTED GENERATION

DG utilizes small generators sited close to electrical demand sources to lower end-users' electric purchases and reduce use of central station power. DG can be an alternative to the traditional electric grid system which relies primarily on large, centrally located power stations and high-voltage transmission lines that connect them to load centers. DG resources can be designed to meet a wide variety of applications, such as cogeneration (also known as combined heat and power), standby power, premium power, peak shaving, grid support, and stand alone generation. DG resources can be operated to make occasional merchant sales into the electric market, in a base load mode to serve a portion of a customer's load requirements, or to provide emergency (or backup) power.

The term DG covers a broad range of technologies and fuels, with no industry-standard definition. The U.S. Department of Energy defines DG as follows:

> Distributed power is modular electric generation or storage located near the point of use. Distributed systems include biomass-based generators, combustion turbines, concentrating solar power and photovoltaic systems, fuel cells, wind turbines, microturbines, engines/generator sets, and storage and control technologies. Distributed resources can either be grid connected or operate independently of the grid. Those connected to the grid are typically interfaced at the distribution system. In contrast to large, central-station power plants, distributed power systems typically range from less than a kilowatt (kW) to tens of megawatts (MW) in size.

2.12.1 DG in Connecticut

DG resources in Connecticut can be grouped into two categories: self-generation units, typically installed at large commercial or industrial facilities that displace some portion of

[95] These locations that provide the greatest score are Fairfield, Bridgeport, Shelton, Stratford, Easton, and Trumbull, all in SWCT.

the facility's outside electric purchases on a regular basis; and emergency generators. According to the Siting Council, there were 71 different facilities that self-generate and utilize the electricity on-site, with a total capacity of 128.45 MW, as of 2001.[96] These include gas, oil, dual-fueled, and other types of units ranging in capacity from 0.01 to 25 MW. The emergency generation capacity in Connecticut comprises thousands of emergency generators located at institutional and industrial sites ranging in size from several kW to 2 MW. Although emergency units include propane and natural gas-fueled generators, the vast majority are generally older and less efficient diesel fuel units with minimal air pollution controls. The DEP maintains a database of emergency generators, roughly 400 of which are located in SWCT with a collective generating capacity of roughly 110 MW.[97] Separately, in August 2002, the DOE issued a report that inventoried the emergency generators in SWCT (with slightly different results than the DEP), as shown in Table 15.

Table 15 – DOE Inventory of Emergency Generators in SWCT

Fuel Type	Number of Units	Capacity (MW)
16 Critical Cities		
Diesel	120	
Natural Gas	13	
Propane	3	
Fuel Type Unknown	26	
Sub-total	162	62.29
36 Cities "of Special Concern"		
Diesel	164	
Natural Gas	23	
Propane	1	
Fuel Type Unknown	81	
Sub-total	269	61.24
Grand Total	431	123.53

The DOE Report, *Improving Transmission Reliability: The Role of Emergency Generation in Southwest Connecticut*, also concluded that, "…emergency generators can considerably support the [SWCT transmission] system by allowing consumers to disconnect themselves from the grid and produce power locally during times of peak demand." The DOE Report also agreed with other analyses that, in a competitive electric market, emergency generators can mitigate price spikes during times of peak demand.

Acknowledging the potential role of DG in improving reliability for SWCT, but also recognizing the potential air quality impact of emergency generators, the DEP initiated a new General Permit program in April 2002. This program is intended to allow DG units of equal to or greater than 50 hp (roughly 37.3 kW) in SWCT to operate when called

[96] Connecticut Siting Council, *Review of the Connecticut Electric Utilities' Twenty-Year Forecasts of Loads and Resources*, October 2001, Appendix A.
[97] See DPUC Order in Docket No. 02-04-12, at 33.

upon by ISO-NE under the demand response program provided the unit complies with specified general permit conditions. Specifically, when ISO-NE declares Operating Procedure No. 4 Step 12 or higher, the permitted DG unit can operate for up to 300 hours in a rolling 12-month period. These hours are in addition to the hours of operation allowed for the facility's own emergency or backup use. Further, the General Permit requires use of ultra-low sulfur fuel, and imposes strict emission limits for NO_x, SO_2, and particulate matter. The Waterside Power Project was permitted under this general permit program. However, an analysis submitted in the DPUC's investigation of possible shortages in SWCT (Docket 02-04-12) concluded that the vast majority of diesel units in Connecticut cannot meet the DEP's NO_x standard.

The DPUC supports DG as a potential means to address reliability concerns in SWCT and across the state, but recognized that "there was little factual evidence of the potential for DG in SWCT."[98] The DPUC also noted that the lack of transmission capacity in the region may be a hindrance to DG development. Additional critical barriers to the more widespread use of DG resources include lack of technology maturation, lack of manufacturing economies of scale, regulatory barriers such as high stand-by rates,[99] inconsistent interconnection requirements, and other permitting and siting hurdles.[100] These issues are being explored in a parallel study by Xenergy commissioned by the ISE. This study is currently in preparation, and will be issued on or about January 2, 2003.

2.12.2 Current Initiatives to Promote DG

In February 2000, the CEAB issued its *Energy Policy Report: Possibilities for the New Century*. The report proposed potential actions to improve the development opportunities of DG resources, including:

- Review existing interconnection standards and explore the development of statewide interconnection standards.
- Develop a statewide policy regarding standby rates and related utility rates that balance the importance of removing DG barriers and the importance of maintaining fair and reasonable rates for customers that do not self generate.
- Coordinate activities of state agencies to identify and address barriers that impede development of new technology.
- Support pilot program(s) to improve planning and operational methods to address grid stability and reliability.
- Support development of systems for demand-side bidding by ISO-NE.

[98] Decision in Docket No. 02-04-12.
[99] The Connecticut DPUC has recently released a decision on Stand-by Rates in Docket 02-02-06 that requires the customer to pay a standby rate of $60/kW-yr to act as backup to the cogeneration capacity.
[100] FERC is currently evaluating standardized interconnection procedures for small generators. See FERC RM02-12.

- Review implementation and scope of net metering regulations for possible expansion.

- Encourage high-efficiency cogeneration and combined heat and power where appropriate and consistent with other state policy goals.

- Maintain solar contractor licensing and training.

- Encourage efficient production and distribution technologies/infrastructure.

- Encourage retrofit programs in transmission and distribution constrained areas, incorporating the value of DG benefits with the development of cost avoidance measures.

There are a number of DG programs in Connecticut and regionally, described as follows:

<u>Property Tax Exemption</u> – Connecticut allows municipalities the option of offering a property tax exemption for certain renewable energy systems. This exception varies from one municipality to another, but is typically for the total value of the qualifying renewable energy system and can be applied to residential, commercial, and industrial property.

<u>Connecticut System Benefits Charge</u> – PA 98-28, Section 44 implemented a System Benefits Charge (SBC) to develop renewable energy and DG facilities in Connecticut. The SBC, currently 0.75 mill/kWh through 2003 – an increase from 0.5 mill/kWh from 2000-2001 – is projected to generate roughly $118 million over five years. In 2004, the SBC increases to 1.0 mills/kWh. There is no sunset date placed on the charge. To be considered for investment, a renewable energy developer must have a business plan that demonstrates that the investment will:

- Benefit Connecticut ratepayers,

- Stimulate the demand for or production of clean energy, and

- Involve one of the clean-energy technologies listed in the legislation: solar, wind, ocean thermal, wave or tidal, fuel cells, landfill gas, low emission advanced biomass conversion technologies, and other non-fossil/non-nuclear technologies with high commercialization potential.

The renewable energy SBC is held by the CCEF. The CCEF was created by the Connecticut General Assembly in 1998 (PA 98-28) as part of legislation deregulating electric utilities. Current annual funding for the CCEF's activities, based on the 0.75 mill/kWh SBC, is approximately $22.5 million. As an example of the activities sponsored by the CCEF, the agency recently committed $2.3 million to purchase and install a fuel cell at the South Windsor High School, which serves as a regional emergency shelter. The PC25 Fuel Cell was manufactured and installed by South Windsor-based UTC Fuel Cells, a division of United Technologies Corporation.

In October 2002, the CCEF announced the commencement of its PV Program for commercial, industrial and institutional buildings. Interested parties must have submitted a pre-application by December 13, 2002, to participate in the RFP, which will be issued in January 2003. The funding available under the program will total $1 million for all selected projects.[101]

The CCEF also recently announced that enXco, a wind power developer and leading provider of asset management services to the wind industry, has been granted funding to create a new company in the northeast. CCEF and enXco will be working together to manage the newly formed company, Northeast Renewable Energy, LLC. They will concentrate on finding optimal wind sites in New England as well as building a series of additional potential wind energy projects.

Connecticut Innovations – Connecticut Innovations (CI) manages a venture fund that invests in Connecticut-based firms, including those that develop DG and renewable energy technologies. The Connecticut Legislature created CI in 1989 and charged it with growing Connecticut's entrepreneurial, technology economy by making venture and other investments.[102] Working alongside CCEF, CI invests in regional firms that improve the efficiency or cost-effectiveness of DG and renewable technologies. CI began with an infusion of taxpayer dollars, but is now self-sufficient by re-investing profits from one venture into the next. Since 1995, CCEF has disbursed more than $58 million in investments and program initiatives. CI's energy-related investments include Proton Energy Systems Inc. of Rocky Hill, Connecticut, that designs, develops and manufactures proton exchange membrane electrochemical products used to produce HOGEN® hydrogen generators and UNIGEN fuel cell systems.

Connecticut Renewable Portfolio Standard – RPS, in general, is a requirement placed upon load-serving entities (including investor-owned utilities and independent marketers) to fulfill a certain percentage of their energy sales through renewable or DG resources. Various forms of RPS are currently required in 12 states, primarily as a component of retail competition, and three states have voluntary RPS programs.[103]

Section 25 of PA 98-28 instituted a RPS in which 6% of all end-use power in Connecticut must be supplied by renewable sources beginning in July 2000, ramping up to 13% in 2009.[104] However, in 1999 the DPUC in Docket 99-03-36 ruled that this requirement does not apply to utility standard offer service, which currently covers the vast majority of customers. The DPUC noted that while RPS compliance is a license requirement for competitive suppliers, the legislature had exempted utilities from this requirement in their

[101] See www.ctcleanenergy.com/news/archives/n102002_solor_pv.html.
[102] In addition to energy-related companies, CI invests in entities that specialize in biotechnology, information technology, and photonics.
[103] Three additional states (Hawaii, Illinois and Minnesota) have implemented "voluntary" RPS programs.
[104] Separate generation requirements are provided for renewables classified as "Class I" or "Class II".

provision of standard offer service. It also noted that the companies that provide power to the utilities for standard offer service are engaged in wholesale transactions, and therefore are not subject to the RPS. The DPUC has not yet addressed the issue of whether the RPS applies to the utilities in their provision of back-up or default service after standard offer service expires in 2004. According to an OLR Research Report, it appears that the same arguments apply to these services as applied to standard offer service, and that utilities may continue to be exempt from the RPS requirement.

The RPS also does not apply to municipal electric utilities, municipal electric energy cooperatives, and electric cooperatives. Municipal electric utilities are not required to meet restructuring requirements, but may choose to "opt-in" to competition if they wish, in which case they would be subject to the RPS. The consequence of these exemptions is that almost all energy in Connecticut is exempt from RPS.

<u>New England Generation Information System</u> – In order to support various state initiatives to promote renewable energy, DG, so-called green energy, and general disclosure requirements, ISO-NE, in conjunction with NEPOOL and an outside vendor recently implemented the New England Generation Information System.[105] The system, considered the first of its kind, was developed to become the accounting and market framework to support these state initiatives.[106] The system tracks a variety of "attributes" for every MWh produced in, or imported into, New England, including fuel source, emission characteristics, plant location, and even whether the generating facility is staffed with union labor. Attributes deemed to have value in supporting any given state's portfolio requirement can be purchased, sold or traded in the form of certificates. For example, load-serving entities (such as traditional utilities or competitive suppliers) can satisfy a state's RPS by procuring renewable energy credits (RECs) that are consistent with the state RPS program. Certificate credits are considered an unbundled, tradable commodity, wholly separate from the electrons that comprise the MWh of energy. The certificate associated with a given MWh can only be sold once by the generation entity, but then traded and banked for up to three years.

Over the first two annual quarters of trading, roughly 8 million RECs traded hands, primarily to meet the requirements of the Massachusetts RPS.[107] Early assessments of the program indicate that a significant premium is placed on renewable energy. The cost of such RECs is estimated to be between \$15 and \$28 per certificate, which represents the price premium placed on each MWh of renewable energy qualified to meet the Massachusetts RPS program, over and above the cost of the electricity.

[105] The program was developed by Automated Power Exchange, Inc. under direction of ISO-NE and funded by the New England Power Pool. Of the six New England states, four require disclosure of generation attributes (MA, CT, ME, RI), three invoke an RPS (MA, CT, ME), and two invoke a generation portfolio standard (MA, CT).

[106] See "What Color is Your Electricity," by Andrew Greene, *Public Utility Fortnightly*, July 1, 2002.

[107] See presentation of Ashley Houston to the Massachusetts Electric Restructuring Roundtable, December 13, 2002.

Utility and ISO-NE Initiatives - During the 1980s, UI offered a special rate to encourage customers to operate their emergency generators when called upon. The program, however, ended when new air compliance regulations restricted the use of those facilities. CL&P has a program to identify, fund, and manage products that advance the efficiency of electric use while enhancing the state's environment and economy. The program is funded by CL&P customers through the Conservation Charge included in customer bills. CL&P may fund up to $5 million in total for these projects, with a maximum of $1 million for single projects. The program allows CL&P to invest in energy efficiency, DG, or renewables.

ISO-NE has a LRP that allows customers to operate their back-up generators either in order to reduce their reliance on power transmitted through the grid, or when system reliability is threatened. However, as of June 2002, the DPUC reported that no customers with backup generation have participated in this LRP. ISO-NE's LRP program is discussed in greater detail in Section 2.11.4.

2.12.3 DG Technology Assessment

Table 16 provides data for commercially available DG technologies in simple-cycle mode, taken from the *Siting Council Review of the Connecticut Electric Utilities' Ten Year Forecast of Loads and Resources*, November 2002. In cogeneration mode, electricity and steam are produced sequentially, which can improve DG efficiency and cost-effectiveness. Cogeneration is generally implemented through "standard" technologies, in which the exhaust from combustion turbines or other engines is captured in heat recovery steam generators to produce thermal energy. These technologies are readily implemented at customers' facilities where steam or hot water requirements are large and relatively consistent throughout the year. Fuel cell efficiencies can approach 80% in cogeneration applications, which is considered critical in terms of project economics for fuel cells to reach commercial application.

DG technology is constantly changing, as are the commercial applications of DG resources. An expanded discussion of DG technologies is being provided in a separate report by Xenergy.

Table 16 – Distributed Generation Technologies[108]

Technology	Size	Efficiency	Turnkey Cost ($/kW)
Combustion Turbine	1 MW – 30 MW	21 - 40%	650 – 900
Reciprocating Engine	30 kW – 10 MW	30 - 43%	500 – 900
Microturbine	30 kW – 400 kW	25 - 30%	600 - 1,100
Fuel Cell	50kW – 1 MW	35 - 54%	1,900 - 3,500
Photovoltaics	1kW+	10 - 20%	5,000 – 10,000
Wind	1 kW – 20kW	12 - 38%	1,000 – 2,500

Reciprocating Engines - Reciprocating engines, also known as internal combustion engines, are a widespread and well-known technology. They currently offer low capital cost, rapid start-up, proven reliability, good load-following characteristics, and heat recovery potential. Reciprocating engine generators for distributed power applications, commonly called gensets, are found universally in sizes from less than 5 kW to over 7 MW.[109] Gensets are frequently used as a backup power supply in residential, commercial, and industrial applications. When used in combination with a 1 to 5 minute uninterruptible power supply, the system is able to supply seamless power during a utility outage. In addition, large reciprocating engine generators may be used for base load, grid support, or peak shaving.

Reciprocating engines are generally less expensive than competing technologies. They also have start-up times as low as ten seconds, compared to emerging technologies that may take hours to reach steady-state operation. Reciprocating engines have efficiencies that range from 30% to 43%. In the future, engine manufacturers are targeting lower fuel consumption and higher shaft efficiencies up to 50% to 55% in large engines (>1 MW) by 2010.[110]

One problem with reciprocating engines is that uncontrolled NO_x emissions (especially from diesel engines) are the highest among DG technologies. Emission rates from manufacturer to manufacturer, and for engine types within a manufacturer's product line may vary considerably. Reasons for these variations include differences in combustion chamber geometry, fuel air mixing patterns, fuel/air ratio, combustion technique, and ignition timing from model to model. Selected NO_x and CO emission levels for reciprocating engines are listed in Table 17.

[108] *Connecticut Siting Council Review of the Connecticut Utilities' Ten Year Forecast of Loads and Resources*, November 2002, Table 4.
[109] The California Energy Commission has extensive information on reciprocating engines and other GD technologies at http://www.energy.ca.gov/distgen/equipment/reciprocating_engines/applications.html.
[110] See http://www.energy.ca.gov/distgen/equipment/reciprocating_engines/performance.html.

Table 17 – Emissions from Reciprocating Engines[111]

	Natural Gas Engine Exhaust Gas ppmv @ 15% O_2	**Diesel Fuel Engine** Exhaust Gas ppmv @ 15% O_2
Uncontrolled NO_x	45-200	450-1,600
NO_x with SCR[112]	4-20	45-160
Uncontrolled CO	140-700	40-140
CO with Oxidation Catalyst	10-70	3-13

Three basic types of post-combustion catalytic control systems for reciprocating engines include:

- Three-Way Catalyst Systems that reduce NO_x, CO and unburned hydrocarbons by 90% or more are widely used for automotive applications.
- Selective Catalytic Reduction (SCR), normally used with relatively large (>2 MW) lean-burn reciprocating engines to reduce NO_x by about 80 to 95%. In SCR, a NO_x-reducing agent, such as ammonia is injected into the hot exhaust gas before it passes through a catalytic reactor.
- Oxidation Catalysts promote the oxidation of CO and unburned hydrocarbons to carbon dioxide and water. CO conversions of 95% or more are achievable.

Other performance-related items for reciprocating engines include:

- Startup times range between 0.5 and 15 minutes;
- They have a high tolerance for starts and stops;
- Engine performance ratings are based on an elevation of 1,500 feet above sea level. Deratings of about 2 to 3% for each additional 1,000 feet are common;
- Deratings of 1 to 2% for every 10°F above the reference temperature (usually 90°F) are common;
- Internal combustion engine heads and blocks are rebuilt after about 8,000 hours of operation; and
- Regular oil and filter changes are required at 700 to 1,000 hours of operation.

Significant research and development efforts are underway to continue to improve the efficiency and reduce the emissions of reciprocating engines. Two significant initiatives

[111] Ibid.
[112] Selective catalytic reduction, a common post-combustion emission control technology.

are the Advanced Reciprocating Engine Systems (ARES) program run by the DOE and the Advanced Reciprocating Internal Combustion Engines program run by the California Energy Commission.

DOE's ARES program focuses on the following performance targets for the next generation of reciprocating engines:

- High Efficiency - seeking fuel-to-electricity efficiency (low heating value) of 50% by 2010, a 30% increase from today's average efficiency.

- Environment - through improvements in efficiency, combustion methods, and emissions control, the ARES program is seeking a 95% decrease from today's NO_x emissions rate with no deterioration in unit availability or in control of other emissions.

- Fuel Flexibility - seeking to develop efficient, dual fuel-capable engines.

- Cost of Power - working to meet a target for busbar energy costs, including operating and maintenance costs, which is 10% less than current state-of-the-art engine systems while meeting new projected environmental requirements.

- Availability, Reliability, and Maintainability - the program's goal is to maintain levels equivalent to current state-of-the-art systems.

California's Advanced Reciprocating Internal Combustion Engine (ARICE) program seeks solutions for reducing emissions so that reciprocating engine can be used for reliable, cheap, energy-efficient, and environmentally clean DG in California. The California Energy Commission is working with major public and private stakeholders to develop an action plan. The program was developed to:

- Facilitate the research, development, demonstration, deployment, and commercialization of ARICE technologies by funding projects in partnership with stakeholders;

- Implement an inter-departmental policy for the utilization of efficient, clean ARICE technologies in DG;

- Work with utilities and regulators to adopt policies that encourage the use of ARICE systems for DG and other appropriate applications.

<u>Wind Power</u> – In 1981, the U.S. had 10 MW of wind power generation capability installed. By 2000, the capacity of domestic wind turbines had grown to 2,554 MW. According to the American Wind Energy Association (AWEA), by 2001, that value grew by 67% to 4,261 MW.[113] Due, in part, to the cyclical nature of project development, AWEA expects roughly 400 to 450 MW of wind capacity to be installed in 2002,

[113] See www.awea.org/news/news020814mkt.html

followed by over 2,000 MW in 2003. While wind power may not be practical in urban locations, remote loads may benefit from local wind turbines under the right wind and economic conditions.

The potential wind resource base in the U.S. is enormous, estimated by AWEA at 10,777 billion kWh annually – three times the total quantity of electricity generated in the U.S. today. At a 30% load factor,[114] that quantity translates to 4,100 GW of capacity. However, the majority of this wind resource can be found in minimally-populated regions far away from load centers, such as in North Dakota, South Dakota, Kansas, Montana, Nebraska, and other mid-continent states.

The economics of wind energy are highly dependent upon the wind speed at a given project site. AWEA estimates that wind-produced electricity costs 4.8¢/kWh at wind speeds of 15.99 miles per hour (MPH) and 2.6¢/kWh at 20.85 MPH. Production economics are also dictated by the height of the turbine tower and the radius of the turbine blade. Additional drivers in the economics are the size of the wind farm (larger facilities allowing for economies of scale), favorable federal (and sometimes state) tax treatment, financing environment, and backup power rates, among other things. The most economic applications for wind (those with highest average wind speeds) are along ridge tops and coastlines – which raises siting issues related to destruction of natural beauty.

Proposals for offshore wind farms have received significant attention lately. One company called Winergy, has undertaken an ambitious plan to identify 25 potential wind farm locations along the east coast with a total capacity of 12,500 MW. In Massachusetts, Winergy is working with Cape Wind Associates to evaluate the feasibility of a 420 MW wind farm off of Cape Cod. Winergy has proposed projects off the coasts of New York, New Jersey, Delaware, Virginia and Maryland.

<u>Fuel Cells</u> – Fuel cells have received a lot of attention in the past several years for stationary power and transportation end-uses. As relatively clean, low-impact resources, fuel cells are viewed positively for urban DG applications. Fuel cell have several benefits which make them highly desirable, including high reliability, ease of siting/permitting due to very low emissions, modularity, and high efficiency.

Fuel cells produce electricity by converting hydrogen to water in the presence of a catalyst. When pure hydrogen is supplied to a fuel cell, it reacts with oxygen from the air to produce electricity, heat, and water as the sole by-products. When natural gas is used, fuel cells have to separate out the hydrogen using a reforming process that emits other by-products, such as NO_x, in trace amounts.[115] Most fuel cells in use employ phosphoric acid technology, and are utilized in cogeneration applications in order to maximize

[114] AWEA estimated that the 4,265 MW of current wind capacity generated 11.2 billion kWh of energy, representing a 30% load factor

[115] For more information on fuel cells, see http://www.epa.gov/chp/pdf/EPA%20Fuel%20Cell%20final%206-18-02.pdf.

efficiency. Fuel cells are being developed using at least ten competing technologies, including phosphoric acid, proton exchange membrane, molten carbonate, solid oxide, alkaline, direct methanol, regenerative, zinc air, and protonic ceramic. Competing technologies offer improvements over phosphoric acid in terms of efficiency, costs over the long term, and suitability in various applications. The solid oxide fuel cell may be the most desirable fuel cell for generating electricity from hydrocarbon fuels because it is simple, highly efficient, tolerant to impurities, and can at least partially internally reform hydrocarbon fuels.

There are presently 200 fuel cell stationary plants producing electricity worldwide, representing roughly 75 MW of capacity.[116] The majority of installations are in Japan (75%) with others in North America (15%) and Europe (9%). Partners Toshiba and International Fuel Cells have produced over 70% of the active fuel cell resource base. It is also worth noting that there are two major fuel cell manufacturers in Connecticut – Fuel Cell Energy and United Technologies, Inc. Both organizations are major employers, and their presence in the state has ramifications for state planning regarding renewable energy and DG priorities.

Fuel cells for residential applications are currently in the demonstration phase. Units the size of a refrigerator produce between 2 kW and 5 kW of electricity and have been implemented in pilot programs in the recent past.

Fuel cells in transportation have garnered considerable praise, in part due to the relatively clean emissions. Certain auto makers, including Toyota, Honda, and Daimler Chrysler, are developing fuel cell-based cars. Toyota and Honda planned to make such cars available on a limited basis in Japan and the U.S. in December 2002, with additional roll out in the future. Fuel cells for automotive use, such as those developed by Ballard Power, rely on polymer electrolyte technology.[117]

<u>Microturbines</u> – Microturbines are a new type of combustion turbine being used for stationary energy generation applications. They are small combustion turbines in packages approximately the size of a refrigerator, with outputs of 25 kW to 500 kW, and can be located on sites with space limitations. Microturbines are composed of a compressor, combustor, turbine, alternator, recuperator, and generator. Waste heat recovery can be used in cogeneration applications to achieve energy efficiency levels greater than 80%. In addition to power generation, microturbines offer a relatively clean solution to direct mechanical drive markets such as compression and air conditioning.

DOE's Advanced Microturbine Program is a six-year program for FY 2000-2006 with a government investment of over $60 million. End-use applications are being targeted for the industrial, commercial, and institutional sectors. The program includes competitive solicitations for engine conceptual design, development, evaluation, and demonstration of components, sub-systems, materials, combustion technology, sensors and controls.

[116] "Fuel Cells: Generating Enthusiasm," Ken Silverstein, *Scientech.*
[117] See www.eyeforfuelcells.com

The primary goals for this program focus on the following performance targets for the next generation of "ultra-clean, high efficiency" microturbine product designs:

- High Efficiency - Fuel-to-electricity conversion efficiency of at least 40%.
- Environment - NO_x < 7 ppm (natural gas).
- Durability - 11,000 hours of reliable operations between major overhauls and a service life of at least 45,000 hours.
- Cost of Power - System costs < $500/kW, costs of electricity that are competitive with the alternatives (including grid) for market applications.
- Fuel Flexibility - Options for using multiple fuels including diesel, ethanol, landfill gas, and bio-fuels.

Photovoltaics – PV, often referred to as solar cells, are semiconductor devices that convert sunlight into DC electricity. Groups of PV cells are electrically configured into modules and arrays, which can be used to charge batteries, operate motors, and power electrical loads. With the appropriate power conversion equipment, PV systems can produce AC compatible with conventional appliances, and operate in parallel with and interconnected to the utility grid.

The first conventional PV cells were produced in the late 1950s, and throughout the 1960s were principally used to provide electrical power for earth-orbiting satellites. In the 1970s, improvements in manufacturing, performance, and quality of PV modules helped to reduce costs and opened up a number of opportunities for powering remote applications, including battery charging for navigational aids, signals, telecommunications equipment, and other critical, low power needs.

Following the energy crises of the 1970s, there were significant efforts to develop PV power systems for residential and commercial uses for stand-alone, remote power as well as for utility-connected applications. During the same period, international applications for PV systems to power rural health clinics, refrigeration, water pumping, telecommunications, and off-grid households increased dramatically, and remain a major portion of the present world market for PV products. Today, the industry’s production of PV modules is growing at approximately 25% annually, and major programs in the U.S., Japan, and Europe are accelerating the implementation of PV systems.

PV systems have a number of merits and unique advantages over conventional power-generating technologies. PV systems have no moving parts, are modular, easily expandable and even transportable in some cases. The fuel (sunlight) is free, there is no noise or pollution, and PV systems that are well designed and properly installed require minimal maintenance and have long service lifetimes.

At present, the high capital cost of PV systems is the primary limiting factor for the technology. In addition, PV systems require considerable surface area requirements and electricity cannot be produced without sunlight.

Significant gains on the efficiency and cost-effectiveness of PV have been made over the years. While the earliest PV devices converted about 1 to 2% of sunlight energy into electric energy, current PV devices convert 7 to 17% of light energy into electric energy. Recent technological advances include the development of PV modules that produce standard AC electricity. Both Ascension Technology of Massachusetts and Advanced Energy Systems of New Hampshire have been recognized for their microinverter technology that eliminates the need for an inverter to convert DC to AC, allowing greater access to homes and small businesses.[118] Also, DOE, under the PVs Building Opportunities in the U.S. program, has developed a rooftop PV system that alleviates the need for conventional roofing shingles or other roofing materials and that can be economically and aesthetically integrated into residential and commercial buildings.

At present, PV represents only a small fraction of the domestic generating capacity. According to the EIA, there is roughly 5 MW of PV capacity in the U.S., representing 0.001% of total capacity. Worldwide PV cell and module shipments reached 99.7 MW in 2001, up 11% from 88.2 peak MW in 2000. The industrial sector was the largest market for PV cells and modules with 29 peak MW in 2000. Both the residential and industrial sectors have benefited from new government sponsored tax credits and loan subsidies in Japan and Germany. The U.S. has implemented a "Million Solar Roofs Initiative" program at the state and national levels as well as various loan programs. An increasing number of U.S. utilities sponsor programs such as net metering, RPS, and green pricing that will encourage PV.

[118] See http://www.eren.doe.gov/pv/pvmenu.cgi?site=pv&idx=2&body=newsinfo.html

3 CONCLUSIONS

This report acknowledges that the Working Group's activities as required by PA 02-95 have provided extensive benefits to the general public as well as the stakeholders comprising the membership of the Working Group. These benefits have been realized through the availability of the all-encompassing public information docket[119] and, most significantly, the Working Group's many meetings, all of which have been open to, and were well attended by, the public. The presentations and exchange during these meetings, many of which have been televised and thus accessible to additional significant segments of the public throughout the state on an on-going basis, offered to all participants a comprehensive education on past, present, and future energy planning in the state and the region. This education included an extensive review of specific projects and the universe of potential alternatives to meet the energy needs of the state and the region going forward. This free exchange of information and broader participation of affected stakeholders outside the traditional utility and energy participant community should be a blueprint for future project approval processes and a significant improvement of what has existed up to now.

In accordance with the requirements of PA 02-95, the Working Group has addressed each of the three elements of Section 2. The Working Group's conclusions with respect to each element are based on the extensive information obtained during the collaborative meetings and summarized as Section 3 of this Assessment Report.

(A) The economic considerations and environmental preferences and appropriateness of installing such transmission lines underground or overhead;

The Working Group has examined the relative economics of overhead and underground transmission lines both for the specific CL&P Bethel-Norwalk transmission line expansion, and for electric transmission line projects in general. Economic factors that were specifically considered include:

- Capital costs for the project, on a per mile basis, for each of the project alternatives proposed by CL&P: the 345/115 kV OH, and the 345 kV OH and the 345 kV UG configurations, as contained in the CL&P application (Siting Council Docket 217). Rough estimates of the capital costs of the Five Towns' alternative two 115kV underground lines were also prepared and reviewed.

- Capital costs for generic 115 kV and 345 kV underground and overhead electric transmission lines, prepared by CL&P for the Working Group (Appendix E).

- Comparative reliability, availability, and repair costs for underground and overhead electric transmission lines.

[119] DPUC Docket 02-04-23

- Life cycle costs for underground and overhead electric transmission lines that have been periodically prepared for the Siting Council, in accordance with the requirements in CGS Sections 16-50g *et seq*.[120] These studies are limited to 115 kV lines, using commercially proven technologies.

With respect to the Bethel-Norwalk project, the expected capital cost of constructing the underground transmission line alternatives would be higher than the overhead line proposal. The cost differential is project- and location-specific, and depends on a number of factors, including the length of the route, subsurface conditions, terrain, cost of ROW acquisition, crossings of major roadways or other structures, and other construction-related constraints. Depending on these factors, there may be some circumstances where portions of electric transmission lines may be installed underground at comparable or lower cost. In the case of the Bethel-Norwalk line, CL&P estimates that the capital cost of the 345 kV UG Alternative is roughly 50% higher ($55 million) than the overhead proposal when ROW and other costs are considered. This cost differential may not, however, take into account all external costs and non-monetary considerations.

Under a recently issued FERC Order accepting SMD for New England, the cost of the Bethel-Norwalk line might be socialized, that is, spread among customers throughout the entire New England region. It is unclear if the FERC Order to socialize costs would apply to the incremental cost of any underground portion of the transmission line. If CL&P's ratepayers were to absorb the incremental cost of placing the entire 345 kV Bethel-Norwalk line underground, it would cost the average residential ratepayer about $0.21 / month in the first year of operation, equivalent to an 8% increase in CL&P's transmission rate, but less than 1% of the current Connecticut electric rate.

As set out in the legislation, the Working Group has also assessed environmental preferences and appropriateness of installing such transmission lines underground or overhead. While monetary values may not be assignable to environmental costs, the Working Group acknowledges that the public does support consideration of environmental preferences that reflect the subjective value that citizens place on environmental, natural, and cultural resources of the state. The Working Group supports the long-term development of standards that internalize certain recognized costs and values that cannot be adequately reflected by a competitive marketplace. The national development by EPA and the endorsement by FERC of emission credits is one step in that direction. The creation of certain other value units that attempt to place a value on external costs is a reasonable and market-based solution to an important concern.

Along the proposed Bethel-Norwalk line, natural and cultural resources have been identified by the Five Towns, for example, at Cannondale, Wilton Center, and Georgetown National Register Historic Districts, Lambert Commons historic buildings, the Bethel school complex, and the Norwalk and Saugatuck Rivers that drain to the Long Island Sound (a designated Estuary of National Significance).

[120] Acres International Corporation, 1996 and updated 2001, *Life-Cycle Cost Studies for Overhead and Underground Electric Transmission Lines*.

Underground transmission lines placed within existing public roadways will minimize the primary long-term impacts to visual, natural, and cultural resources because they are not visible and require less land clearing and alteration of the natural topography, vegetation, and wildlife habitat. Construction of both underground and overhead transmission lines gives rise to short and long term impacts associated with road building, excavation, erosion and sedimentation, noise, EMF, and traffic. Other potential impacts associated with overhead and underground transmission lines outside of the public roadway include effects on water resources, flora and fauna, land use and recreation, soils, air quality, and on agricultural resources. These impacts and the loss of environmental and cultural values can vary widely depending upon the specific locale of construction, and encompass many factors, including the route, construction type, line design, demographics, and topography.

The Working Group further notes that the state legislature, in the language of CGS Sec. 16-50t(a), requires the Siting Council to prescribe and establish reasonable regulations and standards as it deems necessary and in the public interest relating to "the elimination of overhead electric transmission and distribution lines over appropriate periods of time in accordance with existing applicable technology and the need to provide electric service at the lowest reasonable cost to consumers."

The Siting Council, through PUESA, strives to certify projects that meet the energy reliability needs of the state and the region, while minimizing substantial adverse impacts to the state's environmental resources at the lowest reasonable cost to consumers. The economic and the environmental consequences of installing overhead versus underground transmission lines are highly project and location specific. An optimal solution is one that best balances competing design considerations, environmental preferences, and performance criteria along the entire pathway. Optional approaches may be appropriate in the environmentally sensitive areas identified for the Bethel-Norwalk line, after site-specific reconnaissance and public comment is made as part of the Siting Council proceeding.

The three alternatives for the Bethel-Norwalk line that have received the most consideration are:

- CL&P's preferred overhead 345 kV option;
- CL&P's underground 345 kV option along state roads; and
- The Five Towns' underground two 115 kV option along the same state roads.

Recently, in Docket 217, the Siting Council requested additional information on various combinations of design alternatives using different structure heights, pole types, undergrounding, and route variations.

The Working Group endorses the Siting Council's request to CL&P to provide additional project alternatives that may provide information helpful to improve balancing of various issues that need to be addressed as part of the deliberations on the application for a certificate. These alternatives reflect the location-specific concerns, including environmental, aesthetic, demographic, engineering, and other factors along the Bethel-Norwalk line consistent with the Working Group's discussions on environmental preference standards. The Siting Council's action demonstrates its awareness of the Working Group's activities as these activities have been progressing. The Working Group further recommends that CL&P, parties and interveners, and the public be responsive to the request for this information on alternatives, consistent with applicable recommendations of the Working Group.

In addition, the representatives of the Five Towns and the CFE believe that the environmental risks associated with HPFF underground cable have been overestimated; the Five Towns and the CFE could support the Siting Council if the Siting Council determined it would consider this technology as an alternative to the overhead 345 kV line.

(B) The feasibility of meeting all or part of the electric power needs of the region through distributive generation; and

To fully address element (**B**), the collaborative meetings examined:

- Background information on a range of DG technologies, cost, performance, applications, and environmental impact information for alternatives to transmission infrastructure projects, such as through the siting of targeted DG, C&LM and LRPs.

- Background data on specific DG, C&LM, and LRPs in Connecticut.

- Findings and conclusions regarding DG and other transmission alternatives from DPUC Docket 02-04-12, and from the ISO-NE report on SWCT.

- DG technologies such as fuel cells and microturbines.

- Air emissions and regional environmental consequences associated with DG.

The Working Group concludes that DG is part of a rational response to addressing SWCT's electric power needs. However, DG cannot be the exclusive solution for the SWCT Load Pocket. Barriers that impede penetration of DG in the market include: impacts to air quality from increased emissions of the most common and proven DG technologies; constraints on the current infrastructure for more environmentally-clean fuel supplies, such as natural gas; limits on the distribution system interconnection capacity and lack of interconnection standards; cost of backup electric service and tariff structure; lack of technology maturation, lack of manufacturing economies of scale for innovative technologies; lack of coordination with grid operations; and lack of consumer interest in making capital and operating commitments to these technologies. In addition, the environmental equity concerns related to DG implementation are an additional issue for resolution in any comprehensive response in SWCT.

Connecticut has established programs such as the CCEF to promote the development of clean and efficient DG technologies. The Working Group submits that Connecticut can undertake further measures to align the wholesale and retail markets to advance the business case for DG in order for DG to become an expanded part of the state's energy mix. The Working Group suggests that the legislature and/or state agencies weigh initiatives including administration of a conservation charge on natural gas, standardized regional interconnection requirements and backup tariff rate structure, time-of-use and/or locational pricing to send appropriate market signals, a pilot program for expanded demand side responses, and presumptive standards for air emissions limits.

(C) The electric reliability, operational and safety concerns of the region's transmission system and the technical and economic feasibility of addressing these concerns with currently available transmission system equipment.

The reliability, operational, and safety concerns of the transmission infrastructure serving SWCT and all of Connecticut have been examined in several venues at ISO-NE, the DPUC, and the state's utilities.

ISO-NE performed an initial technical evaluation of CL&P's proposed 345 kV Bethel-Norwalk and Norwalk-Beseck Junction transmission projects and reported those findings in the Interim Report, published in January 2002. The Interim Report identified the limitations of the existing transmission system and developed a design basis for a transmission solution. The final results (included as Appendix G) were presented at the TEAC 13 meeting on December 5, 2002. The final report was not ready for review by the Working Group at the time of this Assessment Report. In the TEAC 13 meeting, ISO-NE reiterated its support for near-term improvements in load response, DG, C&LM, and transmission upgrades throughout SWCT. ISO-NE also added a recommendation that Phase II include a radial line to be extended west from Norwalk to Glenbrook, and that a 115 kV line be built between Norwalk Harbor substation and Stamford. Slide 29 in Appendix G contains ISO-NE's additional recommendations.

ISO-NE performed technical analyses, including contingency cases, of the existing 115 kV system and CL&P's proposed 345 kV loop (overhead proposal and underground alternatives). At the request of the Five Towns, ISO-NE also evaluated a two 115 kV option proposed by Synapse Energy Economics, technical consultant to the four towns of Bethel, Redding, Weston and Wilton.

The existing 115 kV system was found to be inadequate under NEPOOL bulk system reliability criteria for a variety of contingency events. The study also found voltage and short circuit problems with the existing system.

ISO-NE tested the 345 kV loop proposal and the two 115 kV option under a variety of conditions. ISO-NE found that both the 345 kV Bethel-Norwalk line and the two 115 kV option would improve electric reliability in SWCT. Completing the loop with a 345 kV Phase II line would further improve reliability in the near term. As load grows, however, the 345 kV solution avoids more problems and is ISO-NE's recommended solution. ISO-NE concluded that "the two 115 KV plan starts to become overstressed by the time it goes into service." The four towns and the CFE believe that the two 115 kV option is the preferred solution, and that ISO-NE's conclusion concerning the two 115 kV line is not supported by the data.

Recently, ISO-NE issued an updated report, the *Southwestern Connecticut Electric Reliability Study* (December 2002). This report also concludes that SWCT continues to experience peak demands that exceed existing transmission service capabilities and peak demands are forecasted to grow.

The Working Group concurs that SWCT is a load pocket requiring additional resources in order to maintain grid security and reliability objectives. The current energy infrastructure in SWCT is not adequate to serve this area as it continues to experience continued development and economic expansion. The existing transmission system and limited available generation has required that system operators be prepared for load shedding to prevent cascading system outages and voltage collapse. Furthermore, the area is subject to uncertain local generation availability due to economic and environmental concerns, and merchant plant development opportunities are restricted by local transmission and interconnection constraints. Necessary additional resources may comprise a variety of supply and demand-side initiatives, including new transmission, conventional generation, DG, C&LM, and price reforms. While the Working Group did not attempt to reach a consensus for a specific transmission option, the Working Group members do agree that transmission relief is necessary.

In addition to the three elements reviewed above, Section 2 of PA 02-95 requires that this report also consider whether there are legislative changes necessary to implement its recommendations. In setting forth the recommendations, at several points, this report urges that the CECA and the Siting Council hold public hearings in connection with their efforts to adopt and, potentially revise particular criteria relevant to each entity's discharge of its evaluative functions. In establishing and/or affirming these criteria, the Working Group strongly advocates that the proposed CECA and the Siting Council provide frequent and adequate opportunities for meaningful comment and input from the public, the agencies and the developers. Other recommendations of this report pertaining to the administration of a natural gas conservation charge, environmental preference standards and resource audit, revised application guides, transmission options manual, expanded life-cycle analysis, initiatives for development of new generation in SWCT, and the development of a statewide energy plan may be accomplished through enhancements of the existing regulatory framework.

4 DISCUSSION OF ISSUES AND RECOMMENDATIONS

4.1 ENERGY INFRASTRUCTURE PLANNING

4.1.1 Connecticut Energy Coordinating Authority

Proposed electric and gas transmission projects within Connecticut and across Long Island Sound have raised issues for Connecticut planners and regulators. Achieving the Restructuring Act's goals of affordable, safe, and reliable electric service, while balancing environmental and consumer protection, requires a broader perspective than that afforded by the active cooperation of regulators, utilities, and the energy suppliers within the state. Connecticut relies heavily on electric and fuel supplies that are produced outside of the state using pipeline and transmission wires that reach outside New England. Cooperation among the region's electric utilities has produced an integrated high voltage transmission grid that delivers low cost power and improves bulk power system reliability. Significant quantities of hydroelectric power are imported from Quebec. Similarly, interties with New York and New Brunswick provide reliability benefits for all regions. Gas deliverability is also a regional issue that extends far beyond Connecticut and New England. Most of the natural gas used in Connecticut is transported through thousands of miles of pipelines from the Gulf Coast and both western and Atlantic Canada. LNG, is shipped great distances in tankers from liquefaction terminals in Trinidad, Algeria, or more remote production centers.

At the regional level, ISO-NE and NEPOOL are the primary planning entities for electric transmission infrastructure. ISO-NE's regional planning activities are critically important for Connecticut, especially for SWCT. ISO-NE's annual *CELT Report* contains a regional assessment of electric loads and an inventory of resources based on information provided by market participants. Using the *CELT Report* to define certain basic assumptions, ISO-NE prepares the RTEP studies of regional transmission needs, with TEAC input and review. TEAC, a broad-based stakeholder group that convenes approximately once per month, is the vehicle for stakeholder input to the RTEP process.

While multiple Connecticut stakeholders participate in TEAC, there is not a single voice that represents the cohesive energy needs and interests of Connecticut, vetted through the public hearing process and consistent with state energy and environmental policy. Moreover, there is currently no mechanism to maximize the opportunity for RTEP to be consistent with other state policy and planning initiatives, such as the efforts of the OPM, the CEAB, or other master plans, including the Conservation and Development Policies Plan for Connecticut. Although TEAC meetings are open to the public, the active members tend to be regulators, industry representatives, and consumer groups who are involved in energy matters on a day-to-day basis. Affected municipalities and environmental groups in the past have not participated in TEAC meetings.

Within Connecticut, the Siting Council is charged with assembling an annual report of electric energy resources in the state. While the Siting Council has the broad responsibility to balance the need for electric generation and electric transmission lines with environmental protection, neither the Siting Council, DPUC, ISO-NE, nor the utilities themselves can mandate the size, type, or location of new generation to be built. Competitive generators make those decisions based on the "market incentives," making it difficult for transmission and distribution companies to plan for merchant generation that may come on line. At the same time, IRP can no longer be used as a tool for balancing supply resources against demand-side programs, nor for balancing generation against transmission line expansion. It is difficult for the Siting Council to undertake a comparative analysis of alternative competing projects, consider the cumulative impacts from successive projects, or perform a comprehensive review of project benefits and impacts, particularly if such projects are filed in phased or staged applications.

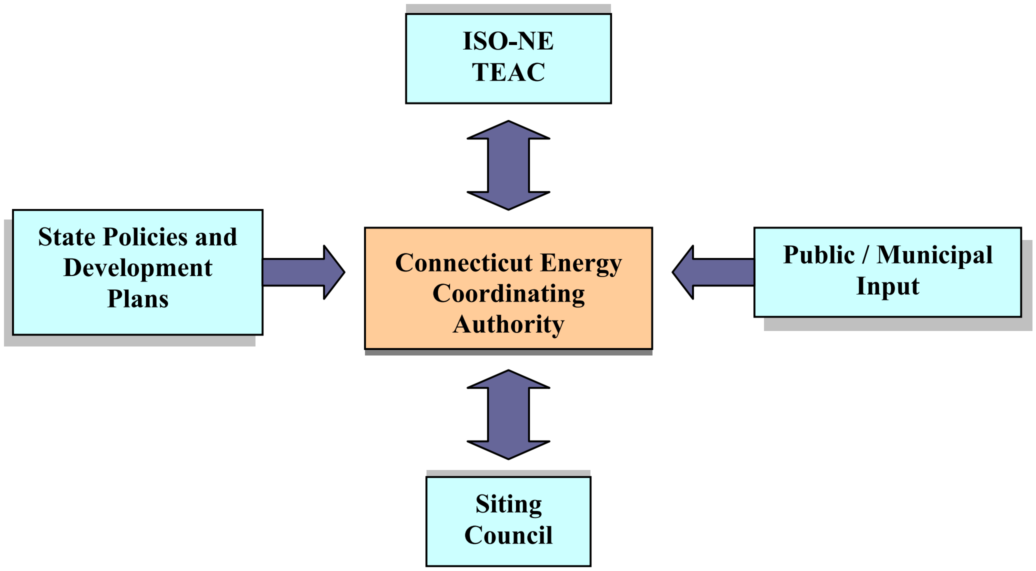
Whereas gas LDCs are regulated along with electric utilities by the DPUC, there is no regional gas scheduling or planning entities similar in function to NEPOOL and ISO-NE. Interstate pipeline companies evaluate market opportunities that warrant expanding or reinforcing their pipeline in order to attract new shippers or to retain existing shippers. Pipelines must apply to FERC for the necessary approval to expand delivery capacity or to abandon existing certificated facilities. Unlike electric utilities, LDCs may choose not to expand distribution service into a new area. Indeed, there are many parts of Connecticut without retail gas service, where residents and businesses rely on fuel oil, propane, or other substitutes. Some gas planning activities are undertaken at the state level or are occasionally taken up by a regional organization such as the New England Conference of Public Utility Commissioners or the New England Governors' Conference. However, most wholesale gas planning activities are undertaken by the transmission pipeline companies and regulated by FERC.

<u>Recommendation</u>: A CECA should be established. The CECA would provide planning, coordination, and public review for energy and associated environmental issues among state agencies, and represent Connecticut's coordinated energy policy and needs before ISO-NE (or successor entities) in the regional planning process. The CECA would have an advisory function and bridge state and regional energy policy and planning efforts. As illustrated in Figure 9, the CECA would coordinate the state's various planning functions and represent the state's interests, defined through public hearings, in TEAC and other regional energy planning efforts.

<u>Membership</u> – Membership of the CECA shall consist of state agencies with primary energy or environmental regulatory or planning mission, including the DPUC, the DEP, OPM, the DECD, and the Department of Agriculture for Long Island Sound crossings. While not functioning as members of CECA, certain other agencies may serve as valuable resources in a consultative role. Such agencies include the Siting Council,[121] Office of Consumer Counsel, and the DOT.

[121] The Siting Council would be precluded from engaging in the collection of extra record evidence, participating in inappropriate *ex-parte* communications, and acting on behalf of the CECA, due to the need to preserve and protect the Siting Council's independence and objectivity, and to avoid the appearance of conflict.

Figure 9 – Connecticut Energy Coordinating Authority



<u>Mission and Purpose</u> – The purpose of the CECA is to provide planning and coordination between agencies substantially involved in energy and environmental issues with ISO-NE (hereinafter to include any successor entity, *i.e.*, Regional Transmission Organization/Independent Transmission Provider) for the purpose of maintaining and improving the reliability and security of regional energy infrastructure; providing input to regional planning processes; promoting energy efficiency, conservation, and technological advances for alternative energy; protecting environmental resources through cumulative impact assessment and comparative analysis; and providing economic analysis of alternatives.

<u>Objectives</u> – The CECA shall have the following advisory functions:

- Compile assessments of existing reports and studies as to the need for new energy resources in Connecticut;
- Review infrastructure proposals of regional significance to be considered in accordance with state energy policy for certification by the Siting Council;
- Participate on ISO-NE TEAC in the development of the RTEP (hereinafter to include any successor planning process);
- Participate on a Regional State Advisory Committee (RSAC), if one forms and it is possible;
- Prepare or adopt an annual energy infrastructure report for the state for natural gas and electric systems; and

- Collaborate at periodic meetings to execute and coordinate its responsibilities among member agencies.

Functions – The CECA:

- May prepare an annual report/assessment of energy infrastructure, or alternatively adopt existing reports by the DPUC, Siting Council, or others, including a rebuttable assessment of adequacy and alternative energy strategies for Connecticut. The report shall be consistent with the Conservation and Development Policies Plan for Connecticut, and other state environmental policies.

- Shall perform initial review of electric and gas infrastructure proposals prior to the Siting Council public convenience and necessity public hearings.

- May solicit possible solutions including an "open season" to identified or potential energy problems.

- Shall evaluate/consider impacts of RTEP on Connecticut's environment and natural resources.

- Shall evaluate/consider and report on the impacts of RTEP functions on energy market design and economic development in Connecticut.

- Shall designate a representative from the CECA to participate in TEAC public meetings.

- Shall encourage participation by municipal representatives from the geographic area(s) affected by proposed projects of regional significance in TEAC public meetings.

- Shall hold state hearings on RTEP and its assumptions including the *CELT Report*, with solicitation of municipal and other public input.

- Shall participate in RSAC (if possible).

- Shall participate in Siting Council forecast proceedings.

- Shall participate in Siting Council life-cycle proceedings.

- May develop and/or review alternative energy planning mechanisms and targets as an alternative to Integrated Resource Planning.

- Shall hold periodic meetings to achieve the objectives of the CECA.

Infrastructure Criteria – The following infrastructure criteria may be developed and/or collected from agencies and industry, and monitored for implementation:

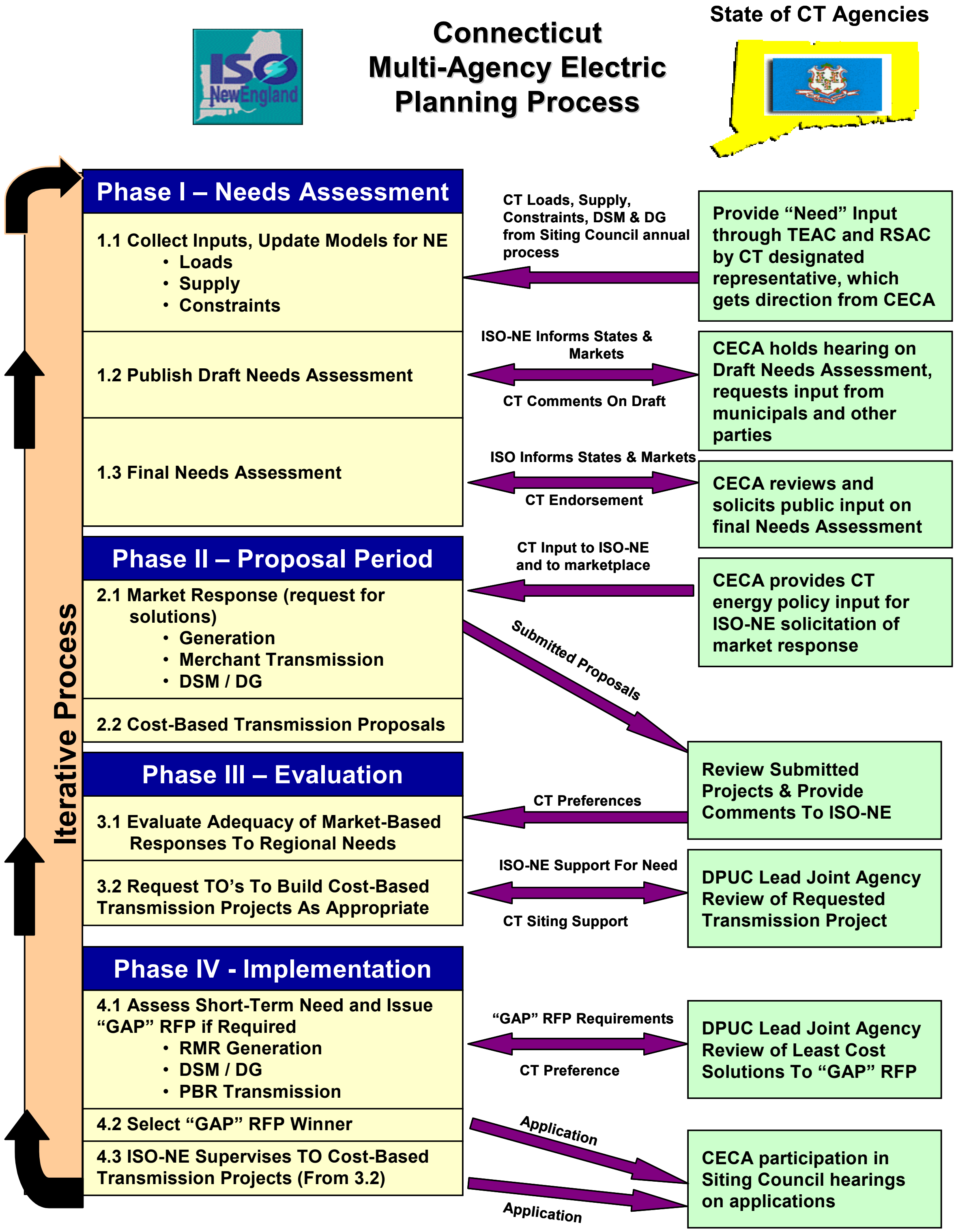
- Environmental preference standards.
- Efficiency standards (*e.g*., transmission, generation, C&LM, and DSM).
- Renewable generation/energy standards (*i.e*., RPS).
- Electric capacity, use trends, and forecasted resource needs.
- Natural gas capacity, use in relation to usage trends, and forecasted resource needs.
- Regional bulk power grid reliability criteria.

Implementation – The CECA will review projects of regional significance for consistency with the State Energy Plan, Conservation and Development Policies Plan for Connecticut, state environmental policy, and/or infrastructure criteria noted above. The CECA will:

- Review energy proposals of regional significance and issue an advisory report with recommendations, during the 60-day pre-application consultation period, pursuant to CGS Sec. 16-50l(e), to the Siting Council, and/or other regulatory agencies or decision-making entities regarding the consistency of proposals with the criteria above. The report of the CECA must be considered by the Siting Council and each agency reviewing a proposal and shall be given the same weight as state agency comments filed pursuant to CGS Sec. 16-50j(h). The filing of siting applications to CECA is a jurisdictional prerequisite for filing an application to the Siting Council. The requirement to file siting applications with CECA at the same time such applications are filed with municipalities will require administrative or statutory change.
- Recommend issuance of a solicitation (request for solutions) for open season to RTEP through TEAC. On its own motion CECA may also issue an open season request for solutions for non-regulated (*i.e*., merchant) projects, generally, or at the time of the pre-application consultation period. Request for solutions shall incorporate/recommend selection criteria that reflect environmental preference standards.
- Recommend to the Siting Council, if appropriate, an extension of the schedule within the Siting Council's existing statutory deadlines (*i.e*., 12 months) to perform a comparative analysis of *bona fide* competing projects identified in the open season.
- Recommend expediting proposals that are consistent with the criteria cited above.

A schematic of the relationship between the CECA and ISO-NE TEAC, illustrating the request for solutions process, is included in Figure 10.

Figure 10 – CECA Planning Process Through TEAC



4.1.2 State Energy Plan

Connecticut's strategic energy planning and policy development responsibilities are currently shared among a number of state agencies:

- OPM is required to prepare a comprehensive energy plan every four years per CGS Sec. 16a-35m, and to produce an annual report that, among other things, identifies state laws, regulations, or procedures that impede energy conservation and load management projects.

- The OPM secretary is the designated state official responsible for policy related to the allocation, conservation, distribution, and consumption of energy resources per CGS Sec. 16a-14.

- CEAB was charged with preparing the February 2000 Energy Policy Report pursuant to Special Act 99-15.

- CEAB submits an annual report with recommendations to the Governor and legislature. In odd years, CEAB addresses the state's energy situation and recommends measures to bring supply/demand into balance, and in even years CEAB must address the implementation of these recommendations and offer additional recommendations.

- The DPUC is responsible for approving utility retail rates, preparing an annual load report, and issuing orders and opinions on specific topical areas.

The above list of activities demonstrates that Connecticut does not have a single body responsible for preparing or coordinating a comprehensive energy policy. As pointed out by a 2002 Legislative Program review, "State energy management efforts are complicated by the multiple goals state government is asked to achieve."[122]

Energy planning must be comprehensive, consistent across state agencies, non-redundant, regional in scope, and take into account the challenges of a competitive environment. While the New York State Energy Plan[123] is commendable and often held up as an example of what should be done, it must be recognized that New York is a one-state electrical power pool, unlike the six states that comprise the ISO-NE region. Moreover, the New York State Energy Planning Board is chaired by the president of the New York State Energy Research and Development Authority (NYSERDA), which administers a public benefits program of approximately $140 million annually funded through a surcharge on retail electric rates. NYSERDA also funds energy efficiency,

[122] Connecticut General Assembly, Legislative Program Review and Investigations Committee Year 2002 Studies, Energy Management by State Government, http://www.cga.state.ct.us/2002/pridata/Studies/Energy_Mgt_Findings_Recs_Report.htm

[123] *New York State Energy Plan and Final Environmental Impact Statement*, June 2002.

environmental protection, low-income assistance, and research and development programs.

Recommendation: **The Working Group and Task Force concur with and reiterate the recommendation of the 2002 Legislative Program Review: "The Connecticut Energy Advisory Board should do an analysis of what would be the appropriate state entity to have responsibility for oversight of state energy policy." In accordance with CEAB's analysis, the appropriate agency should prepare a State Energy Plan that assesses the state's energy resources, summarizes forecasts of loads and capacity, articulates the state's energy policy, and formulates long-range energy planning objectives and strategies.**

The strategies developed in the State Energy Plan should address critical public policy objectives:

- Support safe, secure, economic and reliable operation of Connecticut's energy system infrastructure, and ensure compliance with recognized reliability criteria.

- Stimulate sustainable economic growth, technological innovation, and job growth through market forces.

- Increase energy diversity, energy efficiency, and alternative energy resources, including renewable energy.

- Promote and achieve a clean and healthy environment.

- Ensure fairness, equity and consumer protection in the competitive market.

Strategies for meeting these objectives each give rise to a set of environmental impacts. Tradeoffs between transmission expansion versus generation investment, between demand-side management programs versus additional infrastructure capacity, or among competing fuel types, may result in local as well as regional impacts to air and water quality, agricultural and aquacultural resources, open space, scenic, recreational, and other natural resources. Moreover, these strategies, as well as the siting of infrastructure projects, have environmental equity implications. Within existing state energy policies, Connecticut has established programs and goals with regard to conservation, the use of renewable energy resources, and sustainable development objectives. The proposed State Energy Plan must be consistent with these environmental protection goals. To accomplish this, the State Energy Plan must specifically consider environmental equity and potential significant impacts to air quality, water quality, cultural resources, and other natural resources attributable to the energy strategies incorporated in the State Energy Plan.

Recommendation: **The State Energy Plan should reflect consideration of the cumulative impacts on Connecticut's environment and natural resources reasonably likely to take place with the implementation of the energy strategies incorporated in**

the State Energy Plan. The State Energy Plan should identify significant impacts of the proposed energy strategies on the natural, scenic, cultural, and recreational resources of the state. The State Energy Plan should assess whether the proposed infrastructure strategy disproportionately imposes significantly adverse environmental impacts on any particular demographic / socioeconomic sector within the state. In the Comprehensive Assessment and Report – Part II, the Task Force expects to amplify this recommendation and provide for an assessment of the significant impact of implementation of these energy strategies on Long Island Sound marine and coastal resources in the State Energy Plan.

4.2 PROJECT REVIEW, PERMITTING, AND CERTIFICATION PROCESS

4.2.1 Application Siting Guide

Connecticut possesses one of the most comprehensive programs for certifying and permitting energy facilities in the U.S. With respect to the siting of power plants and electric, fuel, and telecommunication transmission facilities, the Siting Council has broad jurisdiction, diverse representation, and a clear legislative mandate to balance public need or benefit with environmental protection. Regarding the issuance of construction and operating permits, the authorized state agencies, primarily the DEP, have the jurisdiction, expertise and resources to provide a thorough review and impact analysis of proposed projects. The combination of state and federal environmental protection laws and regulations provide a comprehensive framework for mitigating the impact of energy infrastructure projects on the environment.

The Working Group and Task Force members generally concur that the project certification and permitting regulations prescribe a sound framework for evaluating individual energy infrastructure (and telecommunication) projects. However, project reviewers, including the DEP, elected officials, environmental and consumer interest groups, and other stakeholders have expressed concern that the minimum information that currently must be included in certificate applications, in accordance with CGS Sec. 16-50l, can lack sufficient detail to allow the Siting Council to make fully informed decisions and to allow intervenors to comprehend project impacts sufficiently. Many site-specific and environmental components of a proposed project are not fully identified and assessed until after Siting Council approval, during the preparation of a D&M plan.

Project proponents and developers may also be frustrated by the lack of specificity in the Siting Council Application guides, and benefit from more clarity with respect to the state's environmental policies, priorities and preferences. Project developers need to understand as fully as possible the amount of investment that will be at risk in pursuing certification and permitting. New investment in Connecticut's energy infrastructure will be deterred if the application process demands too much detail and at-risk engineering cost. Developers, and regulators and the public support a balance in the level of detail necessary for the application. All participants expect that the process will be transparent, public, and consistent with market forces.

<u>Recommendation</u>: **Through the public hearing and review process, the Siting Council should review and, where appropriate, revise the Application Siting Guide for Electric and Fuel Transmission Line Facilities to assure that it incorporates the information that the Siting Council will need to conduct a diligent and sufficient environmental project-specific review.** Currently the Application Siting Guide is largely based on the general statutory elements prescribed in CGS Sec. 16-50l. Other relevant guidance and manuals, such as parts of the OLISP Connecticut Coastal Management Manual, may be incorporated by reference. In addition, an up-front scoping phase should be encouraged so that the Siting Council and the applicant can agree on or stipulate to the required application's content.

In developing this recommendation, the Working Group completed an initial proposed revision to the Application Siting Guide for Electric and Fuel Transmission Line Facilities, included as Appendix C of this report. The revised Application Guide focuses on information relevant to land-based transmission projects. The Task Force is currently developing a similar document specifically relevant to submarine infrastructure projects and the potential impacts on aquatic resources in Long Island Sound.

4.2.2 Environmental Preference Standards

Under the current process, projects must be reviewed *in seriatum*, on each project's individual merits. The cumulative impact of multiple projects may be considered by the Siting Council, but the process could better facilitate this assessment. There should be a mechanism to gauge proposed projects against alternative competing infrastructure projects, or against alternative competing demand-side programs or other alternative innovative solutions. The prescribed regulatory timelines and milestones do not always allow such alternative competing projects and alternative solutions to be grouped to facilitate some level of concurrent comparative review.

In issuing permits, the DEP gauges the project against applicable regulatory requirements. If the proposed project and mitigation measures meet the minimum regulatory thresholds, then DEP must issue the permit. There is no mechanism for threshold comparative environmental analysis of alternative competing projects.

<u>Recommendation</u>: **Through a public hearing and review process, the CECA should establish the environmental values and preference standards to be utilized in the CECA's concurrent comparative review of competing projects and solutions.** These environmental preference standards must be consistent with the DEP's policy to "avoid, minimize, mitigate" adverse impacts to the environment. If adverse impacts cannot reasonably be avoided, an acceptable project should minimize such impact, and mitigate unavoidable adverse resulting effects. Under certain conditions, compensation to the public trust or to private landowners or leaseholders may be appropriately considered.

The Working Group has utilized this policy framework to develop a set of environmental preference standards, included herein as Appendix H, that are intended to be applicable to the construction of electric transmission facilities, and provide for an assessment of significant adverse environmental impacts of overhead and underground alternatives. The Working Group's environmental preference standards are intended to meet, in part, the legislative requirements of PA 02-95. In the context of the CECA, the environmental preference standards represent the environmental preferences and policies underlying the natural gas and electric system projects in the CECA's annual energy infrastructure report. In parallel, the Task Force is preparing a similar set of environmental preference standards that will apply to an assessment of potential significant adverse environmental impacts to Long Island Sound and marine resources.

4.2.3 Transmission Options Manual

Environmental preference standards must be applied against a backdrop of industry safety standards, performance standards and engineering constraints of overhead and underground transmission line design. The informed public should be aware of environmental impacts and values, as well as engineering and safety standards and best practices. Providing current technical and engineering information to the public will facilitate more constructive participation.

Recommendation: The CECA should commission a Transmission Options Manual, to be updated periodically, that describes the safety, engineering, and reliability parameters for overhead and underground transmission line design.

A Manual of Overhead and Underground Technologies (Options Manual), prepared for the Working Group by CL&P, has been reviewed and approved by the Working Group. This manual provides technical information regarding the options for transmission line construction and is included in Appendix E.

4.3 UNDERGROUND AND OVERHEAD ELECTRIC TRANSMISSION LINES

4.3.1 Transmission Project Economics and Rate Impacts

CL&P's application for the proposed 345 kV Bethel-Norwalk transmission line includes capital and life-cycle costs for the preferred project and two alternatives. One of the alternatives (345 kV UG) involves keeping the existing 115 kV line within the current ROW and installing a 345 kV circuit underground along existing public roadways. This underground 345 kV circuit, consisting of two parallel sets of cables, would have a lower power-transfer capacity than CL&P's preferred 345 kV OH proposal. The Working Group was provided with three sources of underground cable costs on a capital (or first cost) basis and on a lifecycle cost basis (as shown in Table 18): CL&P's application and the record in Docket 217, CL&P's Options Manual prepared for the Working Group, and the Life-Cycle Cost Studies (1996 cost estimates updated to 2001).

Table 18 – Sources of Overhead and Underground Cost Data

Data Source	Voltages (kV)	Capital Costs	Life-Cycle Costs	ROW included	Substations included
CL&P Application	345	Yes	Yes	Yes	Yes
Transmission Line Options Manual	115 and 345	Yes	No	No	No
Life-Cycle Cost Studies	115	Yes	Yes	No	Yes

Underground versus Overhead Costs – Capital costs in the CL&P application are expressed in year 2002 dollars, while life-cycle costs are expressed as present value costs in year 2004 dollars and include carrying charges associated with capital, O&M costs, energy losses, and capacity. The scope and capital costs presented in CL&P's application were subsequently revised in Docket 217 and escalated to July 2003 dollars, but the life-cycle costs were not similarly revised.

Table 19 – Bethel-Norwalk Transmission Line
Underground versus Overhead Costs Without Adjustments ($ millions)

	345/115 kV OH Proposal	345 kV UG Alternative	Difference
Reported Capital Cost (2002 $)	$ 127	$ 182	$ 55 or *+43%*
Reported Lifecycle Cost (2004 $)	$ 195	$ 274	$ 79 or *+41%*

According to CL&P's data in Docket 217, the 345 kV UG Alternative is 43% more expensive than the preferred 345/115 kV OH Proposal on a capital cost basis. The Life-Cycle Cost Studies reported significantly larger percentage differences (500 to 600%) between the capital costs of underground and overhead 115 kV lines of equal capacity. The 345 kV UG Alternative is also 41% more expensive than the preferred 345/115 kV OH Proposal on a life-cycle cost basis. The Life-Cycle Cost Studies showed that underground O&M cost and power loss savings over time would result in life-cycle cost percentages more significantly below the capital cost percentage differences between overhead and underground 115 kV lines of equal capacities. For example, the Life Cycle Cost Studies found that while the capital cost of 115 kV underground cable lines is five to six times higher than an equal capacity overhead line, the life-cycle cost ratio is reduced to three to four times higher.

Some reasons for the smaller capital cost percentage difference in CL&P's estimates for the 345 kV Bethel-Norwalk transmission project are:

- Over $40 million of substation costs are common to each alternative.
- The 345 kV UG Alternative does not match the power-transfer capacity of the 345/115 kV OH Proposal.

- $33.7 million of right-of-way acquisition costs and $4.3 million of ancillary 115 kV line rebuilding costs are included for the 345/115 OH Proposal.

An important reason why CL&P's life-cycle versus capital cost percentage difference is less than the difference reported in the Life-Cycle Cost Studies is that CL&P assumed a higher, not lower, O&M cost for the 345 kV UG Alternative. CL&P used an O&M cost allowance of 0.1% of capital facilities cost for the preferred 345/115 kV OH Proposal and 0.3% of capital facilities cost for the 345 kV UG Alternative. CL&P considers the 345 kV UG Alternative, unlike the 115 kV underground lines in the Life-Cycle Cost Studies, to rely on unproven, prototype technology. CL&P expects more failures and high repair costs, so it estimated an O&M cost premium rather than an O&M cost savings for the underground line. These O&M cost percentages were applied against the larger capital cost for the 345 kV alternative. Another reason for this difference is that the larger than usual conductor size in CL&P's 345/115 kV OH Proposal reduces line losses compared to the 345 kV UG Alternative.

Cost per Mile Comparison – In order to compare CL&P's line cost data in Docket 217 to cost data from the Options Manual, ROW, ancillary line rebuild, and substation costs were eliminated from the preferred 345/115 kV OH Proposal and the 345 kV UG Alternative. The remaining costs were divided by the circuit miles – 20.1 miles for the preferred 345/115 kV OH line and 21.6 miles for the 345 kV UG Alternative. The resulting costs per mile are provided in Table 20.

Table 20 – Bethel-Norwalk Transmission Line Underground versus Overhead Costs without ROW and Substation Costs ($ millions)

	345/115 kV OH Proposal	345 kV UG Alternative	Ratio
Total Capital Cost	$ 127.4	$ 182.1	n/a
Less ROW Costs	$ 32.3	$ 0.0	n/a
Less Ancillary 115 kV Line Costs	$ 4.3	$ 0.0	n/a
Less Substation Costs	$ 41.7	$ 48.4	n/a
Net Cost of Line	$ 50.2	$ 136.8	+ 173%
Cost per Mile	($2.5 / Mile)	($6.3 / Mile)	

CL&P's estimated capital costs for the Bethel-Norwalk line are compared to those in the Options Manual on a per mile basis, as shown in Table 21. While the underground comparison is close, there is still a difference in the overhead comparison. The difference in Table 21 for the 345/115 kV OH line may be partially explained by the following factors:

- 2003 (Docket 217) versus 2002 (Options Manual) dollars;

- The additional costs ($0.15 million/mile) associated with CL&P's proposed use of a larger conductor size;

- The additional costs of CL&P's expectation of achieving an average span length less than the 700-foot basis in the Options Manual;
- The additional costs ($0.13 million) of a fiber optic cable; and
- The costs of ROW clearing and accessway improvements ($0.10 million).

Table 21 – Capital Costs per Mile – Overhead versus Underground ($ million)

	Overhead (345/115 kV)	Underground (345 kV XLPE)
CL&P application (excluding ROW and substations)	$ 2.6 / mile	$ 6.1 / mile
Options Manual	$ 2.0 / mile	$ 6.4 / mile

The Life-Cycle Cost Studies only considered equal-capacity 115 kV overhead and underground lines, so it is not possible to compare the costs with CL&P's estimated project costs. However, it is possible to compare the 115 kV costs from the Life-Cycle Cost Studies with those in the Options Manual. Table 22 indicates that the costs in the Life-Cycle Cost Studies and the Options Manual for a 115 kV double circuit overhead line using steel poles, a 115 kV single circuit underground solid dielectric XLPE cable, and a 115 kV double circuit underground XLPE cable are all relatively close.

Table 22 – Capital Cost per Mile – Bethel Norwalk Alternatives ($ million)

	115 kV OH Double Circuit	115 kV UG Single Circuit	115 kV UG Double Circuit
Options Manual	$ 1.1 / mile	$ 3.0 / mile	$ 5.0 / mile
Life-Cycle Cost Studies	$ 0.83 / mile	$ 2.92 / mile	$ 5.65 / mile

<u>Rate Impacts</u> – Consistent with the recent FERC Order,[124] NEPOOL is considering new market rules for allocating the cost of transmission upgrades and expansions. Until NEPOOL develops such transmission cost allocation rules, the impact of the Bethel-Norwalk project on Connecticut ratepayers is impossible to accurately estimate. However, it is possible to provide an order of magnitude estimate under certain specified assumptions.

If the new transmission cost allocation rules do not accept the incremental cost for putting the line underground, then rate impacts can be estimated as follows:

[124] 101 FERC 61,344

- This analysis is based on CL&P's estimated Phase I capital and life-cycle costs for the preferred 345/115 kV OH Proposal and the 345 kV UG Alternative, and an average residential customer use of 754 kWh/month based on current usage data.
- If the Phase I 345 kV UG Alternative was constructed and the entire incremental cost of putting that line underground was allocated to Connecticut ratepayers, the rate impact would be about 0.028 ¢/kWh in the first year of operation, 2005. This would be equivalent to $0.21 per month for an average residential customer, and this amount would decrease over time as the capital cost is amortized.
- If one-half of the Phase I line was put underground, and the entire incremental cost was allocated to Connecticut ratepayers, the rate impact would be about $0.014 ¢/kWh in the first year of operation, 2005, equivalent to $0.10 per month for an average residential customer, and would decrease over time.

Table 23 – Potential First Year (2005) Rate Impacts of Underground Transmission Costs for the Bethel-Norwalk 345 kV Line

Underground Portion	0%	50%	100%
Incremental Capital Cost (millions)	$0	$28	$55
Rate Impact	socialized	0.014 ¢/kWh	0.028 ¢/kWh
CL&P Transmission Cost Impact	socialized	+ 4%	+ 8%
Monthly Cost	socialized	$0.10	$0.21

Recommendation: The life-cycle cost analyses for underground versus overhead lines that are performed every five years by the Siting Council per CGS Sec. 16-50r, to date, have been limited to 115 kV transmission lines. To assist in the evaluation of the full financial impact of transmission reinforcements and expansions, future studies should include 345 kV transmission lines.

4.3.2 Transmission Study Protocol

Transmission studies assess the reliability of proposed transmission expansion projects under a number of different contingency scenarios. These transmission studies should continue to be performed in a consistent manner so that alternative designs and projects can be effectively compared. For the benefit of the Working Group, ISO-NE has prepared a workable Transmission Study Protocol. The Working Group has reviewed and approved this Transmission Study Protocol, included in Appendix I. This protocol includes a consistent set of assumptions and standards for comparative modeling of transmission alternatives.

Recommendation: ISO-NE should adhere to a standard protocol for developing, modeling, and implementing transmission studies under the auspices of TEAC.

4.4 GENERATION AND DISTRIBUTED GENERATION ALTERNATIVES

4.4.1 Utility Ownership of Generation and Distributed Generation

According to the RTEP02 Report, a transmission solution is required in SWCT because there has not been a sufficient market response (*i.e.*, DG, C&LM, load response, or large generating resources) in that area. In addition to supporting a transmission line solution, the RTEP02 Report included the recommendation that state regulators "implement measures to promote distributed resource programs." In Docket No. 02-04-12, the DPUC also found that clean DG offers many benefits to areas like SWCT, and recommended "that the Legislature consider allowing the distribution companies to own and operate site-specific generation and DG units for a limited time to alleviate problems in SWCT if the market will not provide an adequate response."

Ownership and Other Issues – Utilities are in a suitable position to develop DG in a problem area, given their understanding of load flows and distribution network capacities/limitations. Utilities could finance reliability generating units through rate base and recover capital and operating costs as a prudent and necessary expense through rates. However, utility ownership of reliability units also creates issues since rival generators may feel competitively disadvantaged. Regulators and ratepayers may experience utility ownership of reliability units as a step backward from the competitive generation market already implemented in New England.

The counter-argument is that utility ownership of generation is needed because of a failure of the market to respond to a *bona fide* need and that this generation therefore does not compete with other merchant power plants. Once the transmission line is completed, however, load-pocket constraints may be tempered or eliminated; hence, the unit will cease to be required for reliability, and it will indeed compete against merchant generators. At such point in time where a utility owned generator earmarked for reliability is indeed competing with merchant plants in New England, the utility could be required to sell the unit. Any under-recovery or over-recovery of costs could then be accounted for through stranded costs.

In the event that markets fail to provide a solution to reliability problems, utilities can avoid competing with merchant generators by issuing RFPs for third parties who arguably may be better suited to develop and own reliability units in a particular area up to a specified total capacity. The winning bidder would be the party that agrees to implement reliability units of sufficient quantity and reliability at the lowest price. This alternative would insure that utilities do not exercise market power by "crowding out" third parties. Such an approach is analogous to ISO-NE's Emergency Capability Supplement RFP for emergency capacity that led to a merchant generation company implementing the Waterside Project. There are many other issues to consider:

- Substituting DG for transmission expansion brings generation closer to load and closer to areas of higher population densities. Because small diesel and simple cycle gas turbine generators generally have higher emission rates and are less efficient than large central-station plants, the net emissions (for the same energy generated) from DG may be greater, if this type of DG is relied upon.

- Environmental equity is another consideration when generation is located in urban areas where there already are industrial and manufacturing externalities.

- The DEP's new General Permit program for DG SWCT will expire on December 31, 2003. This program would need to be extended to allow long-term operation of such DG resources.

If utilities or third parties are encouraged to develop and own DG, there should be regulatory provisions to facilitate permitting and siting approval. There are a number of ways to define DG to qualify for such treatment:[125]

- Distribution Interconnection – DG could be limited to interconnecting at distribution-level voltages. Most distribution lines are rated at 13.8 kV and below; some is at 23 kV and a small amount at up to 33 kV. A 13.8 kV line limits the DG unit capacity to an absolute maximum of 7 to 8 MW, and generally much less, perhaps 1 to 2 MW depending upon the local network flows and configuration.

- Size Limit – There are currently Siting Council and other agency divisions that apply to certain review and approval processes, *e.g.,* 5 MW for emergency generators or 25 MW for Qualifying Facilities such as cogeneration.

- Technology Limitations – DG could be restricted to certain technologies, such as fuel cells and renewable resources that are considered environmentally preferable. One consequence of such a technology limitation would be that small diesel engines or as microturbines might be prohibited, unless they had emission controls and/or cogenerated thermal energy to improve their overall fuel efficiency.

- Functional Limitation – Utility ownership of DG, or rate-based support of third party development, could be limited to situations where DG is a cost-effective solution to an identified reliability, voltage support, or grid stability problem, and the competitive market has not responded sufficiently.

- Congestion Management – Transmission congestion results in high generation costs in a load pocket as local units are dispatched out-of-merit order. Nevertheless, DG could be cost-effective if the resulting reduction in generation costs outweighed the DG costs.

Units larger than DG could be developed to address reliability, voltage support, or grid stability problems. These larger reliability units might be considered "must-run" because

[125] There may not need to be any size limitations for on-site DG units that reduce customer loads.

they are required for reliability, and therefore would be entitled to collect revenues based on costs and a reasonable return on capital.[126] Such units could be installed on a temporary basis to meet short-term reliability requirements until a permanent solution is put in place. For example, the 69 MW Waterside Power Project located in Stamford was implemented last summer as a short-term emergency response to demand in the NOR sub-area.

<u>Recommendation</u> – The DPUC should evaluate the benefits and legal authority of utility ownership of DG and of generation as a reliability asset, as well as define the limitations for such ownership. Utility ownership of such reliability units should be discussed with a different group of stakeholders, including generators and regulators, in order to address issues of market competition.

4.4.2 Promoting DG, C&LM, and Load Response

DG has the potential to ease the strain on the existing transmission and distribution systems, and possibly to delay system upgrades or expansions in the future. The barriers to DG development, along with DG potential, are more thoroughly discussed in the Xenergy report, *An Analysis of DG and C&LM Opportunities for Southwest Connecticut*. The lack of a common interconnection standard is a key barrier – utilities have differing interconnection standards that could be made consistent within Connecticut and throughout New England. There is also the question of whether the existing market structure provides DG and other transmission alternative developers with the efficient market signals.

<u>Recommendation:</u> DG pilot programs should be developed in targeted areas, with DPUC oversight and a suitable cost recovery mechanism, that can demonstrate potential cost-effective applications to avoid or to complement transmission upgrade or expansion projects.

<u>Recommendation:</u> The DPUC should continue to follow, and actively participate as necessary, in the current FERC investigation[127] on interconnection standards for small and large generators.

[126] This was the situation faced by Consolidated Edison Company of New York, in which electric reliability in New York City was threatened. NYPA responded by siting a total of about 454 MW gas turbine peaker units in and around New York City through a fast-track permitting and construction progress. On Long Island, LIPA installed about 200 MW of temporary gas turbine generation. All of these units had to follow State Environmental Quality Review and obtain all required permits. It is worth noting that neither NYPA nor LIPA are regulated by the New York Public Service Commission, and the lessons learned from their actions should be carefully assessed.

[127] FERC Docket RM02-12

4.4.3 Conservation Charge on Gas Service

The three gas LDCs in Connecticut, Connecticut Natural Gas Corporation, The Southern Connecticut Gas Company, and Yankee Gas Services Company, currently fund energy efficiency programs within their service territories through the Conservation Adjustment Mechanism. The mechanism, in place since 1995, gives each LDC the flexibility to meet customer demand while allowing a reasonable assurance that prudently spent conservation funds will be recovered.

The Working Group and Task Force recognize that conservation is one key component in Connecticut's energy strategy. The LDCs are well-positioned to further this objective through their existing energy efficiency programs and funding mechanisms.

<u>Recommendation</u>: **The DPUC should expand the scope of the LDCs' current energy efficiency programs and consolidate under the EECG. Using dollars already allocated to efficiency programs, the LDCs should apportion a dollar amount not to exceed their current funding levels for efficiency programs, subject to review and adjustment by the EECG and approval by the DPUC.**

The EECG would be responsible for developing, implementing, and evaluating the cost-effectiveness of energy efficiency programs. The EECG shall consist of a six-member board consisting of a representative from each of the LDCs, the Office of Consumer Counsel, an environmental group, and the DPUC. The EECG will have the flexibility to develop programs within budgetary guidelines and consistent with the efficiency and environmental standards established by the EECG. Administration of the programs may be provided by the ISE or other designated organization as selected by the EECG.

DPUC approval would be required of final program development recommendations and budgets, established within EECG guidelines, prior to implementation by the LDCs. The LDCs will submit plans to the DPUC in accordance with regulations regarding existing integrated resource plan filings. Authorized annual energy efficiency spending will be recovered through the existing recovery mechanisms that exist within each LDC. It is anticipated that the annual program funding will be approximately \$1.5 million (\$0.5 million from each LDC.) The funding should be allocated such that energy efficiency program implementation constitutes no less than 95% of the funding, with program administration, promotion, research and development to account for no more than 5% of the funding.

Recommended energy efficiency programs should address a broad customer base, and may include but not be limited to:

- Residential Insulation and Weatherization Program – free for eligible low income/ hardship customers, and potential co-pay component for non-hardship customers.

- Residential Conservation Services Program – provides low-cost energy audits to homeowners. Required by state law, and administered by the OPM.

- Residential High Efficiency Program – cash rebates for customers who choose high energy efficiency and low emissions heating equipment over standard efficiency models.

- Residential Energy Efficiency Loan Program – administered by the Connecticut Housing Investment Fund, provides financial assistance in the form of below-market interest rate loans to eligible owners for energy efficiency improvements.

- Commercial Energy Grant Program – customers submit energy efficiency proposals during “bidding rounds”. EECG awards grants based on ranking cost-effectiveness of proposed projects.

- Public Act 93-417 State Facilities Program – in conjunction with OPM, state facilities are identified for energy efficiency improvements. Based on proposals, authorized projects are co-funded by the LDC and the OPM.

GLOSSARY

115 kV: 115 kilovolts or 115,000 volts

345 kV: 345 kilovolts or 345,000 volts

AC: Alternating current; an electric current that reverses its direction of flow 60 times a second (60 cycles or 60 hertz) in the U.S.

ACOE: Army Corps of Engineers

Algonquin: Algonquin Gas Transmission Company, a Duke Energy company

AMA: American Medical Association

ARES: Advanced Reciprocating Engine Systems

ARICE: Advanced Reciprocating Internal Combustion Engine

AWEA: American Wind Energy Association

BHE: Bangor Hydro Electric, an RTEP sub-area

Big 11 Power Loop: NEPOOL's original design for 345 kV transmission lines connecting 11 large power plants with load areas

BOSTON: Boston, an RTEP sub-area

C&LM: Conservation and load management

cable: A fully insulated conductor used for transmitting energy or data

capacity: The ability to generate energy, usually measured as kW or MW

CCEF: Connecticut Clean Energy Fund

CEAB: Connecticut Energy Advisory Board

CECA: Connecticut Energy Coordinating Authority

CELT: NEPOOL annual Capacity, Energy, Load and Transmission report

CFE: Connecticut Fund for the Environment

CGS: Connecticut General Statutes

CHC: Connecticut Historical Commission

CI: Connecticut Innovations

circuit: A system of conductors through which an electric current flows

circuit breaker: A switch that automatically disconnects power to the circuit in the event of a fault condition; usually located in substations

CL&P: Connecticut Light & Power Company, a subsidiary of NU, the electric utility that serves most of Connecticut

CLIC: Connecticut Long Island Cable project, proposed by NU

CMA: Connecticut Coastal Management Act

CMA-NMA: Central Massachusetts/Northeastern Massachusetts, an RTEP sub-area

CO: carbon monoxide

Columbia: Columbia Gas Transmission Corporation

conductor: A metallic busbar, wire, or cable that serves as a path for electric flow

conduit: Pipes, usually PVC plastic, typically encased in concrete, for underground power cables

CT: Connecticut, an RTEP sub-area

D&M: Development and Management

DECD: Department of Economic and Community Development

Deficient Load Pocket: A sub-area of an electrical system in which peak demands cannot be met by local generators indicating reliance on transmission import capability, and possibly resulting in voltage disruptions and power outages

demand: The total amount of electricity required at any given time by a utility's customers

DEP: Connecticut Department of Environmental Protection

DG: Distributed generation; small-scale generation, typically less than 5 MW and often located at commercial or industrial sites that can be tied into the local distribution grid

DHS: Department of Health Services

DC: Direct current; electricity that flows continuously in one direction, often used at high voltages for point-to-point power transmission

displacement: Substitution of gas through exchange or backhaul

distribution (line or system): The cables or facilities that transport electrical energy, natural gas, or data from the transmission system to the utility's customers

DOT: Department of Transportation

DPUC: Department of Public Utility Control

DSL: Digital Subscriber Line

DSM: Demand Side Management

Dth: Decatherm, equal to MMBtu

ECMB: Energy Conservation Management Board

EECG: Energy Efficiency Collaborative Group

EFH: Essential Fish Habitat

EIA: Energy Information Administration

ELIE: Eastern Long Island Extension, a proposed Iroquois pipeline project

EMF: Electric and magnetic field

EPA: Environmental Protection Agency

fault: A failure or interruption in an electrical circuit

FERC: Federal Energy Regulatory Commission

Five Towns: Bethel, Redding, Wilton, Weston and Norwalk

force majeure: An unexpected and uncontrollable event

ground wire: Cable that runs above and parallel to the conducting wire, and serves to shunt lightning strikes from the conducting wire to the ground

H-Frame Structure: A structure constructed of two upright poles with a horizontal crossarm and bracings of wood or steel

HDD: Horizontal Directional Drilling

hp: Horsepower

HPFF: High-pressure fluid-filled; a type of underground transmission line

HQ: Hydro-Quebec, an RTEP sub-area

HVAC: High-voltage alternating current, a type of transmission line

HVDC: High-voltage direct current, a type of transmission line

Hz (Hertz): Electric cycles per second, a measure of frequency

ICAP: Installed Capacity

insulators: Ceramic device that isolate an overhead transmission cable from the structure

Interim Report: *The Connecticut Reliability Study – Interim Report*

Iroquois: Iroquois Gas Transmission System, L.P.

IRP: Integrated Resource Planning

ISE: Institute for Sustainable Energy at Eastern Connecticut State University

ISO: Independent system operator

ISO-NE: ISO New England, Inc., New England's independent system operator

kV: Kilovolt, or 1000 volts; a measure of electric potential

kW: Kilowatt, or 1,000 Watts; a measure of electric power

kWh: Kilowatt-hour, or 1,000 Watt-Hours; a measure of electric energy

LAI: Levitan & Associates, Inc.

LDC: Local distribution company providing gas service

line: A group of overhead or underground transmission cables that provide transmission or distribution service

LIPA: Long Island Power Authority

LMP: Locational Marginal Pricing

LNG: Liquefied natural gas

load: Amount of electrical energy required by customers

Load Pocket: A transmission area that has insufficient transmission import capacity and must rely on out-of-merit order local generation

LOLE: Loss of Load Expectation; a measure of bulk power system reliability

LRP: Load Response Program

M&N: Maritimes and Northeast Pipelines, a Duke Energy company

magnetic field: Produced by the flow of electric current and measured as magnetic flux density

ME: Maine, an RTEP sub-area

merit order: The order in which power plants are dispatched to minimize operating costs

mill: One-tenth (1/10) of a cent; 1 Mill / kWh = $ 1 / MWh

MIND: Mass-impregnated non-draining paper; a type of cable used for underground HVDC electric transmission

MMBtu: One Million BTU, equal to a decatherm

MMcf: Million standard cubic feet of gas

MMcf/d: Million standard cubic feet per day

MMPA: Marine Mammal Protection Act of 1972

monopole: Transmission structure consisting of a single tubular steel column with horizontal arms to support insulators and conductors

Municipal Electric Energy Cooperative: A publicly directed joint action supply agency

MVA: Total power

MW: Megawatt, or 1000 kilowatts, a measure of electric power

MWh: Megawatt-hour, or 1000 kWh, a measure of electric energy

NAAQS: National Ambient Air Quality Standards

NAI: Normandeau & Associates, Inc.

NB: New Brunswick, an RTEP sub-area

NDDB: National Diversity Data Base

NEPA: National Environmental Protection Act

NEPOOL: New England Power Pool

NeptuneRTS: Neptune Regional Transmission System

NESC: National Electrical Safety Code

NESCAUM: Northeast States for Coordinated Air Use Management

NH: New Hampshire, an RTEP sub-area

NHPA: National Historic Preservation Act of 1966

NMFS: National Marine Fisheries Service

NOPR: FERC Notice of Proposed Rule Making

NOR: Norwalk/Stamford, an RTEP sub-area

Norwalk/Stamford (Geographic): A subsection of SWCT that comprises the following 13 municipalities: Bridgeport, Darien, Easton, Fairfield, Greenwich, New Canaan, Norwalk, Redding, Ridgefield, Stamford, Weston, Westport, and Wilton

Norwalk/Stamford (Electrical): A subsection of SWCT described by the following interfaces: Plumtree-Ridgefield Jct (1565) 115 kV; Trumbull Jct.-Old Town (1710) 115 kV; Trumbull Jct.-Weston (1730) 115 kV; Pequonnock-RESCO Tap (91001) 115 kV; Pequonnock-Compo (1130) 115 kV

NU: Northeast Utilities, parent company of CL&P as well as Western Massachusetts Electric, Public Service of New Hampshire, Yankee Gas, and other subsidiaries

NY: New York, an RTEP sub-area

NYISO: New York Independent System Operator

NYSERDA: New York State Energy Research and Development Agency

OLISP: Office of Long Island Sound Programs

O&M: Operations and maintenance

OP4: NEPOOL Operating Procedure 4, Actions in a Capacity Deficiency

OPM: Office of Policy and Management

overhead: Electrical facilities installed above ground, usually relying on the air for insulation

PA 02-95: Public Act 02-95, Act Concerning the Protection of Long Island Sound

PA 98-28: Public Act 98-28, the Electric Restructuring Act

Peak Load (or Peak Demand): The maximum customer demand, typically over a one-year period

Phase I: A transmission expansion that would extend the 345 kV transmission line from the Plumtree Substation in Bethel to the Norwalk Substation in Norwalk

Phase II: A transmission expansion that would extend the 345 kV loop from Norwalk to Beseck junction in Wallingford

PJM: The Pennsylvania-New Jersey-Maryland control area

The Plan: *The Conservation and Development Policies Plan for Connecticut 1998-2003*

PNGTS: Portland Natural Gas Transmission System

psig: Pounds per square inch gauge

PTF: Pool Transmission Facilities

PUESA: Public Utilities Environmental Standards Act

PV: Photovoltaic; semiconductor device that converts sunlight into DC electricity

RD&D: Research Development and Demonstration

RECs: Renewable Energy Credits

reconductor: Replacement of existing conductors with new conductors, but with little if any replacement or modification of existing structures

reinforcement: Any of a number of approaches to improve transmission system capacity, including rebuild, reconductor, conversion, and bundling methods

RFP: Request for Proposal

RI: Rhode Island, an RTEP sub-area

RNS: Regional Network Service

ROW: Right-of-way, a corridor for transmission or other facilities

RPS: Renewable Portfolio Standard

RSAC: Regional State Advisory Committee

RTEP: Regional Transmission Expansion Plan prepared by ISO-NE

S-ME: Southern Maine, an RTEP sub-area

SBC: System Benefits Charge

SCFF: Self-contained fluid-filled; a hollow-core cable underground transmission line used primarily for submarine installations

SCR: Selective Catalytic Reduction

SEMA: Southeastern Massachusetts, an RTEP sub-area.

shunt reactor: A reactive power device used to compensate for reactive power demands by transmission lines.

Siting Council: Connecticut Siting Council

SMD: Standard Market Design, proposed by FERC to standardize rules among ISOs

SNET: Southern New England Telephone Company

substation: A fenced-in yard containing switches, transformers and other equipment buildings and structures to monitor and adjust transmission and distribution flows

SWCT: Southwestern Connecticut, an RTEP sub-area

SWCT (geographic): SWCT consists of the following 52 towns and municipalities: Branford, Bridgeport, Darien, Easton, Fairfield, Greenwich, New Canaan, Norwalk, Redding, Ridgefield, Stamford, Weston, Westport, Wilton, Ansonia, Branford, Beacon

Falls, Bethany, Bethel, Bridgewater, Brookfield, Cheshire, Danbury, Derby, East Haven, Hamden, Meriden, Middlebury, Milford, Monroe, Naugatuck, New Fairfield, New Milford, New Haven, Newtown, North Branford, North Haven, Orange, Oxford, Prospect, Roxbury, Seymour, Shelton, Southbury, Stratford, Trumbull, Wallingford, Waterbury, Watertown, West Haven, Woodbridge, and Woodbury

SWCT (electrical): The area served by the four 115 kV busses in Bethel, Watertown, Southington, and New Haven

TCPL: TransCanada Pipeline, Ltd.

TEAC: Transmission Expansion Advisory Committee

TE-CSC: Cross-Sound Cable project, owned by TransEnergie US

Tennessee: Tennessee Gas Pipeline Company, an El Paso Energy company

Texas Eastern: Texas Eastern Transmission Corporation, a Duke Energy company

TO: Transmission owner

Transco: Transcontinental Gas Pipeline

transformer: A device used to transform voltage; a step-up transformer increases the voltage while a step-down transformer decreases voltage

transmission line: Any line that functions to connect electric generators to distribution systems (and large individual loads), generally operating at 69 kV or above

UI: United Illuminating, the electric utility that serves the greater New Haven and Bridgeport areas.

upgrade: Any of a number of approaches to improve transmission system capacity, including rebuild, reconductor, conversion, and bundling methods

USFWS: U.S. Fish and Wildlife Service

VT: Vermont, an RTEP sub-area

voltage: A measure of the force that transmits electricity

W-MA: Western Massachusetts, an RTEP sub-area

wire: See Conductor

XLPE: Cross-linked polyethylene; a type of underground transmission line