APPENDIX A

CONNECTICUT SITING COUNCIL, *WHITE PAPER ON THE SECURITY OF SITING ENERGY FACILITIES*

An Act Concerning Electricity and Energy Efficiency
Public Act 07-242
Section 8

White Paper on the Security of Siting Energy Facilities

Prepared by the Connecticut Siting Council
October 8, 2009

INTRODUCTION

In response to Public Act 07-242, "An Act Concerning Electricity and Energy Efficiency", the Connecticut Siting Council (Council) issues this white paper to establish the Council's scope of review of energy security in regards to the siting of electric transmission and generating facilities. This policy document was developed to comport with relevant parts of Section 8 of the Public Act which states:

> Not later than September 1, 2007, the Connecticut Siting Council, in consultation with the Emergency Management and Homeland Security Coordinating Council, established pursuant to sections 28-1b of the general statutes, and the Department of Public Utility Control shall initiate a contested case proceeding, in accordance with the provisions of chapter 54 of the general statutes, to investigate energy security with regard to the siting of electric generating facilities and transmission facilities, including consideration of planning, preparedness, response and recovery capabilities. The Connecticut Siting Council may conduct such proceedings in an executive session with sensitive information submitted under a protective order.

Pursuant to legislative intent of the Act, this document will review existing regulations and guidelines regarding security for the siting of electric generating and transmission facilities. Energy security is a broad area of review, one that, ironically, grows ever more complex as the nation's energy system becomes more integrated. Security remains a broad concept even when limited to the Council's task of siting—that is, determining the particular locations in Connecticut where electric generating or transmission structures should be placed. The Council will focus mainly on physical threats, as opposed to cyber threats, to electric generating and transmission facilities and on threats that are intentional, ranging from simple trespassing to vandalism to dedicated acts of sabotage.

Generally speaking, siting security in this document does not relate to operational, reliability, and maintenance procedures affecting electric facilities, asset connection requirements, or naturally-caused calamities (for example, hurricanes or ice storms). Most of these security concerns are predictable and the Council already factors them into its siting decisions. Moreover, most storm threats involve the electric distribution system, which is not under the Council's purview.

EXISTING STANDARDS/GUIDELINES

The protection of electric generating and transmission facilities is one of the highest priorities for national/international, regional, and state authorities and organizations, and involves many existing layers of regulation and guidelines issued and monitored by various entities, both public and private. Also, this elaborate security protection regime has built-in mechanisms for updating and changing. Below is a brief overview of the primary existing organizations and procedures that ensure protection for the grid.

National

Presidential Decision Directive 63 "Protecting America's Critical Infrastructures", issued in May 1998, identifies "electricity" as a critical infrastructure. This directive required the U.S. Department of Energy (DOE) to be the lead agency for the protection of critical energy infrastructure (Electricity Sector). The DOE, in turn, designated the North American Electric Reliability Corporation (NERC) as the Electricity Sector Coordinator.

NERC's responsibilities as Sector Coordinator include the following:

- assessment of sector vulnerabilities;
- planning to reduce electric system vulnerabilities;
- development of a system for identifying and averting attacks;
- development of a notification procedure for sector participants and appropriate government agencies when an attack is imminent or underway; and
- assistance in reconstituting minimum essential electric system capabilities after an attack.

In June 2002, NERC issued "Security Guidelines for the Electricity Sector", Version 1.0, that describe general approaches, considerations, practices, and planning philosophies to be applied in protecting electric system infrastructure. The guidelines are voluntary in nature and were developed to help entities develop policies, procedures, practices and strategies to address issues related to security. Each entity can decide if the particular guideline will be used and to what extent, if any. These guidelines, with subsequent additions and revisions, include the following topics:

- Communications
- Continuity of Business Practices
- Continuity of Operations
- Control System - Business Network Electronic Connectivity
- Control System Cyber Security Incident Response Planning
- Patch Management for Control Systems
- Securing Remote Access to Electronic Control and Protection Systems
- Cyber - Access Controls
- Cyber - Intrusion Detection
- Cyber - IT Firewalls
- Cyber - Risk Management
- Employment Background Screening
- Vulnerability and Risk Assessment
- Protecting Potentially Sensitive Information
- Emergency Plans
- Physical Response
- Physical Security

- Physical Security - Substations

In addition to the aforementioned guidelines document, separate voluntary guideline documents were established, as follows:

- Security Guideline for the Electricity Sector -- Threats and Incident Reporting - Version 2, April 2008;
- Security Guideline for the Electricity Sector -- Physical Response - Version 3.0, November 2005; and
- Threat Alert System and Cyber Response Guidelines for the Electricity Sector -- Version 2.0, October 2003.

Although these guidelines remain voluntary, the Energy Policy Act of 2005 delineated a process leading to the development of mandatory standards. The 2005 act authorized the Federal Energy Regulatory Commission (FERC) to designate a national Electric Reliability Organization (ERO). In July 2006, FERC issued an order that certified NERC as the ERO for the United States. Subsequently, NERC transformed many existing voluntary policies into mandatory standards to ensure the proper design, operation and maintenance of the electric system.[1] Standards were developed to address aspects of the design, operation, and maintenance of electric infrastructure, including security.

Security is addressed in the daily operation of the electricity grid and in future planning for the grid. NERC operates the industry's Electricity Sector Information Sharing and Analysis Center (ESISAC) under the U.S. Department of Homeland Security and Public Safety Canada. ESISAC gathers information about security-related threats and incidents, and communicates it to government authorities.

NERC is continually evaluating and modifying its security standards and guidelines to address changing technologies and emerging threats through the Critical Infrastructure Protection Committee (CIPC). Comprised of industry experts in the areas of cyber security, physical security, and operational security, the CIPC coordinates all NERC's security initiatives.

In addition to NERC, the IEEE (formerly known as the Institute of Electrical and Electronics Engineers, Inc.), a professional organization dedicated to the advancement of technology, has taken the initiative on security. Its security guideline, Standard 1402-2000 – IEEE Guide for Electric Power Substation Physical and Electronic Security, issued in June 2000, addresses security issues related to human intrusion during the construction, operation, and maintenance of electric power supply substations. Methods to deter and mitigate intrusions are discussed.

Regional and Interregional

The Northeast Power Coordinating Council (NPCC) is the regional organization that is responsible, under NERC, for the reliability of the electric system throughout Northeastern North America (New York State, the six New England states, and, in Canada, Ontario, Quebec, and the Maritime provinces). NPCC has reliability criteria that address all aspects of the grid, including security. The NPCC criteria have been written to be consistent with the NERC reliability standards, but in some cases they are more stringent and more specific.[2]

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[1] Link to NERC standards web page: <http://www.nerc.com/page.php?cid=2|20>

[2] Link to NPCC documents web page: <http://www.npcc.org/documents/regStandards/Criteria.aspx>

Under NPCC, the Independent System Operator for New England (ISO-NE) is the Regional Transmission Organization (RTO) responsible for ensuring the reliability of the electric system in New England. ISO-NE generally carries out the NPCC reliability criteria—security criteria among them—but also has some of its own security procedures.[3]

Furthermore, as an independent ISO/RTO among its North American peers, ISO-NE participates in various kinds of interregional planning activities and other exercises designed to smooth the transitions between electric systems in different parts of the U.S. and adjoining North American territory, activities that frequently involve sharing ideas and coordinating around security issues. For instance, ISO-NE is part of a Joint ISO/RTO Planning Committee that specifically addresses cross-border aspects of transmission security.

State

At the state level, attending to energy security in its broadest sense, namely, long-term energy sustainability and reliability, is the job of policy and planning bodies such as the Connecticut Energy Advisory Board, the Office of Policy and Management, the Energy Conservation Management Board, and several others. On more immediate aspects of electric system security, the Department of Emergency Management and Homeland Security (DEMHS) coordinates with the utility companies. The Council typically considers physical security of electric facilities during the application process, as necessary.

COMPLIANCE

All bulk power system owners, operators, energy marketers, generators with contracts to sell energy, and local distribution companies must comply with NERC-approved operational and reliability standards. In Connecticut, these entities are required to register with NERC through the Northeast Power Coordinating Council (NPCC), the regional organization that ensures reliability to Northeastern North America. Both NERC and the NPCC conduct compliance reviews to enforce the required standards through assessments, audits, evaluations, investigations and analysis of self-reporting requirements. Entities that do not meet certain criteria are subject to enforcement action through fines or other sanctions.

COUNCIL'S ROLE

Although the task of developing security for the siting of certain aspects and components of electrical infrastructure has been and continues to be examined and addressed by national/international, regional, and state authorities and organizations, the Council will consider specific discussion points in regards to security. The Council's expertise in assessing siting criteria for electric facilities will facilitate heightened awareness and provide for a unique insight regarding security concerns. In addition to these discussion points, the Council will solicit comment from the DEHMS regarding siting security concerns.

The Council may examine these discussion points to ensure that security procedures and standards are consistent with existing guidelines, standards and other criteria. The discussion points probed by the Council may vary from application to application, depending on various factors, and in some cases the number of security questions may be minimal.

[3] Link to ISO-NE procedures: <http://www.iso-ne.com/rules_proceds/index.html>

Some questions asked in the prospective reviews may elicit answers that are highly sensitive. Applicants seeking to submit proprietary information under protective orders shall follow the Council's established procedures.

In considering applications for a Certificate of Environmental Compatibility and Public Need or a Petition for a declaratory ruling, and consistent with PA 07-242 Section 8, the Council will examine security issues around four discussion areas, including but not limited to: Planning, Preparedness, Response and Recovery. The general area of discussion for each topic is presented below.

A. PLANNING

1. Identification

Identify the physical vulnerabilities most likely to pose a security threat.

2. Facility type/characteristics

Identify the type and characteristics of the facility and any ways in which the facility's setting affects security concerns.

3. Interdependencies

Examine any pertinent ways in which the facility is linked to other facilities and systems and potential repercussions from a facility or system interruption.
Examine whether the proximity of the facility to other electric facilities, either dependent or independent, presents security challenges.

4. Awareness

Examine if there is an established method to help regional, state and national security officials maintain situational awareness of this facility.

B. <u>PREPAREDNESS</u>

1. Support infrastructure

Examine site security infrastructure, including site monitoring, physical and non-physical barriers and access controls.

2. Personnel

Review any simulated exercises that include local police, fire, and other emergency response teams.
Examine whether local law enforcement/emergency response liaison is in place, and review mutual aid agreements between affected entities.

C. RESPONSE

1. Access to information

Examine notification procedures to public and/or local officials, including the types of security issues that would warrant such notification.

2. Mitigation

Examine mitigation measures, including alternate routing of power, strategically located spares and mobile backup generation.

Examine whether procedures are in place to ensure that mitigation protects natural resources at the site.

D. RECOVERY

1. Recovery Measures

Identify measures that will be taken, if necessary, to restore natural resources at the site of the facility.

2. Reporting

Determine whether reporting procedures are established to evaluate and improve the effectiveness of local emergency response teams, methods to limit negative impacts on neighboring electric facilities, and restoration of the natural environment.

CONCLUSION

The Council recognizes and agrees that electricity is a critical infrastructure as defined by Presidential Decision Directive 63, "Protecting America's Critical Infrastructure". The Council may also add its own prospective site security review. In doing so, the Council notes that while redundancy is sometimes a problem in any regulatory review, strategic redundancies are actually safeguards. The Council believes that its long-established focus on the local particulars of proposed electric facilities can contribute to the physical security of the grid.

APPENDIX B

CONNECTICUT LIGHT & POWER, *ELECTRIC UTILITY LINE MAINTENANCE PLAN*

Docket No. 11-12-xx

ELECTRIC UTILITY LINE MAINTENANCE PLAN FILED PURSUANT TO SECTION 16-32g OF THE GENERAL STATUTES OF CONNECTICUT AND SECTION 16-32g-1 OF THE REGULATIONS OF CONNECTICUT STATE AGENCIES

2012 FILING

THE CONNECTICUT LIGHT AND POWER COMPANY

January 1, 2012

THE CONNECTICUT LIGHT AND POWER COMPANY
ELECTRIC UTILITY LINE MAINTENANCE PLAN - 2011

This is the 2012 submission of The Connecticut Light and Power Company's ("CL&P" or the "Company") updated Electric Utility Line Maintenance Plan. The Plan has been prepared in accordance with section 16-32g of the General Statutes of Connecticut, section 16-32g-1 of the Regulations of Connecticut State Agencies, and the minimum requirements established by the Department of Public Utility Control ("Department") by letter dated July 13, 1989.

A) Electric System Description

The Department's requirements call for a description of the transmission and distribution system, including the miles of plant for both underground and overhead lines, miles of plant by voltage level and miles of plant by type of construction. In accordance with that requirement, CL&P has prepared a table that contains this information, which is attached as Appendix 1. In addition, the following definitions were used in preparing Appendix 1 and other pertinent parts of this Plan:

Tree - Wire - A conductor with an abrasion-resistant outer covering, usually nonmetallic, and intended for use on overhead lines passing near trees.

Non - Tree Wire - Bare wire or any other wire not intended to withstand abrasion to tree contract.

Aerial Cable - A conductor system in which each conductor is covered with a fully insulated covering.

Spacer Cable - A type of electric supply line construction consisting of an assembly of one or more covered conductors, separated from each other and supported from a messenger by insulating spacers.

Underground Cable - Insulated conductors installed in duct or conduit systems.

Direct Buried Cable - Insulated conductors installed in direct contact with earth or in conduit. Primarily used in residential developments and industrial or commercial parks.

- **As directed by the Department, the Plan includes a map of the CL&P service territory, which indicates the location of major electric utility facilities including transmission lines and substations. The map, entitled Transmission System Key Map, is included as part of Appendix 2.** (This map has not yet been updated to include the Company's recently-energized new transmission facilities.)

  Also included is a list of the names associated with the alpha-numeric substation designation.

- **Also as directed, the number of electric distribution customers served by CL&P by customer class as of September 30, 2011 is as follows:**

Response: The number of customers served by customer class as of September 30, 2011 is:

Residential	1,100,546
Commercial	104,021
Industrial	3321
Public Street Lighting	4231
Railroad	2
Sales for Resale	30
TOTAL	1,212,151 *

* This number is lower than that used in interruption reporting statistics due to the fact that financial accounting counts each account as a customer. Interruption analysis requires that each metered location be considered a customer. Some accounts are a summation of several meter locations.

B) Tree Trimming

- **Recent Changes in Vegetation Management Practices**

  In 2011, CL&P continued to use professional tree trimming and line clearance contractors to perform vegetation management services. As discussed by the Company in 2010 during the proceedings associated with Docket No. 09-12-05, the Company is in the process of changing its tree owner consent process. Prior to 2010, the Company used contractor professionals to obtain consent from all tree owners. This consent was obtained in person, in writing, or verbally. In the new process, the Company intends to obtain consent by sending a letter to tree owners describing the nature of the necessary work and by providing a contact number for questions or concerns. If there is no reply from the tree owner, the Company's tree trimming contractors will then proceed to trim after a specified period of time has elapsed. The Company has piloted this new process during 2010 and has recently begun utilizing it throughout its system for scheduled standard maintenance trimming.

- **Description of Line Clearance Work Force**

  CL&P added the position of Right-of-Way Coordinator to oversee all work on CL&P's distribution right-of-ways in 2008. All eight CL&P Vegetation Management field personnel and one billing clerk report to the Supervisor – CL&P Vegetation Management.

  All maintenance, capital, emergency and storm restoration line clearance work will be performed by line clearance contractors.

- **Standards and Specifications**

  A copy of Northeast Utilities Specification for Local Distribution Line Clearance Tree Work and Brush Control is attached as Appendix 3. The specification was condensed and reformatted in 2008. The technical requirements did not change.

- **Service Areas not trimmed within the Normal Trimming Cycle or to the Current Specifications.**

  All maintenance work - standard maintenance trimming ("SMT"), backbone maintenance enhanced trimming ("BB-METT"), lateral maintenance enhanced trimming ("LAT-METT") and lateral enhanced trimming ("LAT-ETT") - in 2012 will be completed in conformance with the specifications shown in Appendix 3.

  In 2011, CL&P targeted 3,039 miles for maintenance work and 191 miles of LAT-ETT. Through October 2011, 2,460 maintenance miles and 171 LAT-ETT miles were completed.

  In 2012, 3,313 miles of distribution circuits are scheduled for clearing; 3,155 miles are scheduled for maintenance work and 158 miles are scheduled for LAT-ETT.

  Currently, the tree trimming cycle varies circuit-by-circuit because the individual reliability of each circuit helps determine its tree trimming schedule.

- **Tree Trimming Refusals**

  In most cases, denials are resolved and either a partial or a full trim is allowed. In general, tree trimming denials do not represent a major obstacle to CL&P achieving its tree-trimming goals because they represent a relatively small number of miles when compared to the total number of miles trimmed. In 2010, there were 550 tree trimming refusals. Through October 2011, there were 218 refusals.

C) Maintenance Practices

In accordance with the Department's requirements, this section of the Plan includes a detailed description of the Company's inspection, testing, and maintenance practices for transmission and distribution lines and equipment, and any significant changes thereto over the past two years.

- **Description of Distribution Maintenance Organization and Work Force**

  Customer Operations

  The Customer Operations organization covers the operation and maintenance of the CL&P distribution system and shares responsibilities for the construction of the distribution system with System Projects. Customer Operations is composed of three major functions, which are Division Operations, Field Maintenance and Operations Support.

  Energy Delivery

  The Energy Delivery organization includes the planning and engineering of the CL&P overhead and underground distribution system. Energy Delivery is composed of five major functions, which are Engineering, Construction, Stores, Facilities and Transportation. The Energy Delivery organization also has an additional, particular focus on upgrading the Stamford and Greenwich infrastructure.

  Maintenance

  The Maintenance organization is responsible for a major portion of distribution maintenance in Connecticut. This organization is made up of six groups in Connecticut. These are Central Maintenance, Eastern Maintenance, Western Maintenance, Regional Test, Central Maintenance Services, and Maintenance Engineering.

  The Central Maintenance, Eastern Maintenance, and Western Maintenance groups, each headed by a Manager – CL&P Maintenance, have jurisdiction over all distribution substation electrical equipment maintenance and selected overhead electrical equipment maintenance in their respective regions. Each region is divided into multiple districts, each with a supervisor who has responsibility for completing the maintenance work in the district. District Supervision oversees crew complements, makes assignments for crew assignments, arranges for staffing, materials and equipment with local Operations and Technical personnel, and monitors work in progress to determine adherence to safety rules, performance, and construction standards.

The Regional Test group is headed by a Manager – CL&P Test who is responsible for all Connecticut test department activity and Supervisory Control and Data Acquisition ("SCADA") equipment. The test department is made up of four groups with a Supervisor – CL&P Test for each of three regional groups and a centrally-located Supervisor -- Distribution Automation. Test Department Supervision oversees crew staffing, makes assignments for crew assignments, arranges for staffing, materials and equipment with local Operations and Maintenance personnel, and monitors work in progress to determine adherence to safety rules, performance, and construction standards.

The Central Maintenance Services group provides centralized support of maintenance activities, hazardous waste management, distribution transformer repair, and other specialized maintenance services.

The Maintenance Engineering group is responsible for utilizing the work management and maintenance management systems, developing new maintenance methods and programs, investigating equipment problems and failures, and other maintenance related studies. This group is also responsible for the chemistry laboratory, infrared inspection program, and the spare parts inventory.

- **Frequency of Inspection and/or Maintenance**

As an ongoing activity, Company employees routinely observe the condition of distribution plant. This is done as they travel about the Company's service area to perform field assignments as well as going to and from work. In addition, inspection of the plant goes on as field work is being engineered and as it is physically performed.

CL&P also has a comprehensive inspection, testing, and maintenance program for its distribution facilities. A table of the inspection and maintenance procedures, their frequency, and any frequency changes in the past two years is included as Appendix 4. Appendices 5-20 provide complete procedures and brief outlines of policies pertinent to line inspection and maintenance.

This program has the following among its primary objectives:

- The prevention or mitigation of service interruptions
- Extending the useful life of equipment
- Avoiding future, more costly maintenance and repairs
- Assuring compliance with:
  - safety rules and regulations
  - legal requirements
  - contractual agreements

The Northeast Utilities Maintenance Manual ("NUMM") identifies twenty-six maintenance areas to be addressed by the Distribution Maintenance organization in order to reduce outages, add to the useful life of equipment, and reduce system operating costs.

The following is a brief description of the highlights for major topics regarding the inspection, testing, and maintenance practices for distribution lines and equipment:

1. The following Direct Buried equipment is inspected at five-year intervals:

   A. Company Owned direct buried facilities including:
   B. Pad Mounted Transformers
   C. Submersible Transformers
   D. Switch Enclosures
   E. Switchgear
   F. Transclosures
   G. Handholes (HH)
   H. Risers
   I. Fault Indicators
   J. Primary and secondary cable

   Refer to NUMM 5.11 & 6.11 in Appendix 5 for further details.

2. Capacitor Banks

   All pole top and substation capacitor banks are visually inspected once per year. Substation capacitor banks are routinely inspected monthly. This inspection is intended to determine the condition of the tanks, bushings, terminals, connections, etc. The reactive characteristic of air conditioning load requires a high availability of capacitor banks during summer load periods. The inspection is scheduled for March and repairs are scheduled as problems are identified to ensure repairs are completed by June 1st to prepare for summer loads. An annual infrared survey of capacitor banks is also performed.

   Refer to NUMM 5.05 & 6.05 in Appendix 6 for further details.

3. Inspection and Maintenance of pole top Automatic Voltage Regulating Equipment

   Pole top regulators are inspected annually and receive major maintenance as required. All three-phase voltage regulating equipment on circuit backbones receive an annual infrared inspection (Appendix 19).

   Refer to NUMM 5.01 & 6.01 in Appendix 8 for further details.

4. Inspection and Maintenance of Reclosers

   CL&P presently has two types of reclosers, oil-filled and vacuum. In addition, these are further subdivided into SCADA-controlled and Non-SCADA controlled. Presently, SCADA controlled pole top distribution line reclosers are inspected annually and Non-SCADA controlled pole top distribution line reclosers are inspected bi-monthly. Substation distribution line reclosers are inspected monthly.

Refer to NUMM 5.44 & 6.44 in Appendix 9 for further details.

5. Inspection and Maintenance – Network Transformers

Network vaults containing network transformers are handled as follows:

A. Maintenance inspection – Energized - Annually
B. Major Maintenance - De-Energized - Every two years

Refer to NUMM 5.30 & 6.30 in Appendix 12 for further details.

6. Inspection and Maintenance - Underground System - Cable

Network and radial system vaults and manholes containing only cable are inspected at five-year intervals.

Refer to NUMM 5.49 & 6.49in Appendix 14 for further details.

Infrared Inspections in Underground Vaults and Networks are conducted to identify potential problems in primary and secondary cables, network protectors and other underground equipment.

7. Inspection and Maintenance - Street lighting

Street lighting supplied from the underground system is inspected at five-year intervals.

Refer to NUMM 5.48, 5.52and NUMM 6.52 in Appendix 16 for further details.

8. Infrared Inspection

The three-phase backbone portions of all circuits are surveyed annually with infrared.

Refer to NUMM 5.22 Appendix 19 for further details.

9. Distribution Wood Pole Inspection and Treatment

   The Company refocused its wood pole inspection and treatment program in 2008. Going forward, the Company will continue to evaluate the effectiveness of a pole inspection and treatment program along with a capital pole replacement program.

   Refer to NUMM 5.61 & 6.61 and 6.61A in Appendix 10 for further details.

10. Three-Phase Group Operated Switches Inspection and Maintenance

    All three-phase group operated switches are visually inspected once per year.

    At six-year intervals, these switches are operated to check for blade alignment, contact condition, interrupting devices, insulators, arresters, etc. An annual infrared survey of three-phase switches is also performed.

    Refer to NUMM 5.15, 6.15a and 6.15b in Appendix 7 for further details.

11. Inspection and Maintenance of Underground Transformers.

    Radial supplied underground transformers are inspected at five-year intervals.

    Refer to NUMM 5.55 & 6.55 in Appendix 15 for further details.

12. Inspection and Maintenance-Underground System - Vaults and Manholes

    Vaults and manholes are inspected at five-year intervals.

    Refer to NUMM 5.59 & 6.59 in Appendix 17 for further details.

13. Inspection and Maintenance-Underground System-Corrosion

    Anodes are maintained coincident with other underground system inspections.

    Refer to NUMM 5.54 & 6.54 in Appendix 18 for further details.

14. Cyclic Circuit (Feeder) Management Program - All CL&P circuits are scheduled for periodic formal engineering reviews. Refer to Appendix 20 for further details.

- **Current Actual Annual Expenditures**

  The 12-month expenditure for maintenance of overhead distribution plant for the period December 1, 2010 through November 30, 2011 was $44.6 million. This equates to $2,770 per primary circuit mile when divided by 16,102 overhead primary circuit miles.

- **Completed maintenance**

  CL&P performs maintenance of its distribution system on a continuing scheduled basis. A copy of the CL&P's Inspection and Maintenance System Report for the period January 1 through November 30, 2011 including a listing of the appropriate staffing levels necessary to complete the 2012 activities outlined in the Plan as follows:

The Connecticut Light and Power Company Inspection and Maintenance System Report									
January 1 Through November 30, 2011									
System Report						Number of scheduled and completed			
Ref. No	**I&M Program Description**	**Group Responsible**	**Procedure Number**	**Unit Description**	**Total Number of Units**	**Scheduled for 2011**	**Completed by 11/30/2011**	**% completed by 11/30/2011**	**Notes**
1	DB Facilities	Operations	NUMM 5.11	Switch/Transformer	66,892	11,643	10,647	91%	1, 9
2	Capacitor Banks	Maintenance	NUMM 5.05	Capacitor Bank	1,797	1,797	2,218	123%	4
3	Automatic Voltage Regulators	Maintenance	NUMM 5.01	Regulator	820	820	1,142	139%	4
4	Reclosers	Maintenance	NUMM 5.44 - Inspections	Recloser	2,327 (ALL)	5,432 (I)	5,328	98%	2, 4, 6
			NUMM 5.44 - Major		1,309 (OIL)	218 (M)	194	89%	3, 4
5	UG System Network Transformers	Maintenance	NUMM 5.29, 5.30 - Routine Inspection	Transformer/Protector	690	690 (I)	521	76%	4, 5
			NUMM 5.29, 5.30 - Major Maintenance			345 (M)	229	66%	4
6	UG Plant	Operations	NUMM 5.59	UG Structure (Manholes & Vaults)	10,222	683	676	99%	8, 9
7	Subway-Street Lights	Operations	NUMM 5.52	Pole	5,108	1,303	1,443	111%	9
8	Infrared Inspection	Maintenance	NUMM 5.22	Circuit	1,019	1,019	1,019	100%	4

NOTES

1 - Number of units to be done in a given year may vary from the quantities called for in the Frequency Table in Appendix #4 of CL&P's Line Maintenance Plan due to anticipated changes to the units of equipment in service at any time due to upgrades, conversions, retirements, and other adjusments.

2 - Electronic reclosers are inspected Bi-Monthly. Hydraulic reclosers and reclosers with DSCADA are inspected once per year.

3 - With regard to reclosers, CL&P is transitioning from a years-based major maintenance cycle to an operational-based maintenance cycle (i.e. in the future these units will be maintained based upon their number of operations, fault duty, or diagnostic tests rather than once every six years).

4 - Work performed by a combination of CL&P and contractor crews depending on work load and available resources.

5 - In 2008, the Company temporarily suspended its annual inspection cycle to eliminate energized oil tests to comply with an interim practice in accordance with a settlement agreement with OSHA. This Practice continued in 2010

6 - These values may be adjusted at year-end 2011.

7 - The cumulative staffing levels allocated and necssary for the implementation of the above inspection and maintenance programs is equivalent to 66 people working full time, including contractor resources.

8 - Total units inspected include company owned manholes and vaults only.

9 - CL&P has moved from a four (4) year inspection cycle to a five (5) year cycle

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2		Transmission System Maps
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4		Table of Inspection and Maintenance Frequencies
5	NUMM 5.11 6.11	Inspection of Direct-Buried Facilities
6	NUMM 5.05 6.05	Capacitor Bank Inspection
7	NUMM 5.15 6.15A 6.15B	Pole-Mounted, Three-phase, Group Operated Switches
8	NUMM 5.01 6.01	Pole Top Regulators
9	NUMM 5.44 6.44	Reclosers and Sectionalizers
10	NUMM 5.61 6.61 6.61A	Inspection, Treatment, Restoration and Replacement Guidelines for Distribution System Wood Poles
11	NUMM 5.51 6.51	Underground Switches
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APPENDIX 1

TRANSMISSION AND DISTRIBUTION SYSTEM MILES PER CONSTRUCTION TYPE AND VOLTAGE LEVEL

TRANSMISSION AND DISTRIBUTION SYSTEM MILES

PER CONSTRUCTION TYPE AND VOLTAGE CLASS

Transmission			
Construction Type	69 kV Circuit Miles	115 kV Circuit Miles	345 kV Circuit Miles
Non-Tree Wire	97.2	1092.4	433.5
Underground Cable	2.8	86.0*	46.2

Distribution				
Construction Type	5 kV Circuit Miles	15 kV Circuit Miles	25 kV Circuit Miles	35 kV Circuit Miles
Tree Wire	463.95	3766.83	2615.93	55.19
Aerial Cable	5.12	80.69	29.63	19.58
Spacer Cable	37.78	302.60	152.25	25.33
Other Overhead	2315.96	3470.89	2573.67	186.97
Underground**	128.05	3085.45	2776.14	80.21

* This includes three cable circuits 5.8 miles long operating at 138 kV across Long Island Sound to the New York State line that is owned by CL&P. The remaining length is owned by the Long Island Power Authority.

** Includes both Direct Buried and Conventional Duct-Type Circuit Miles.

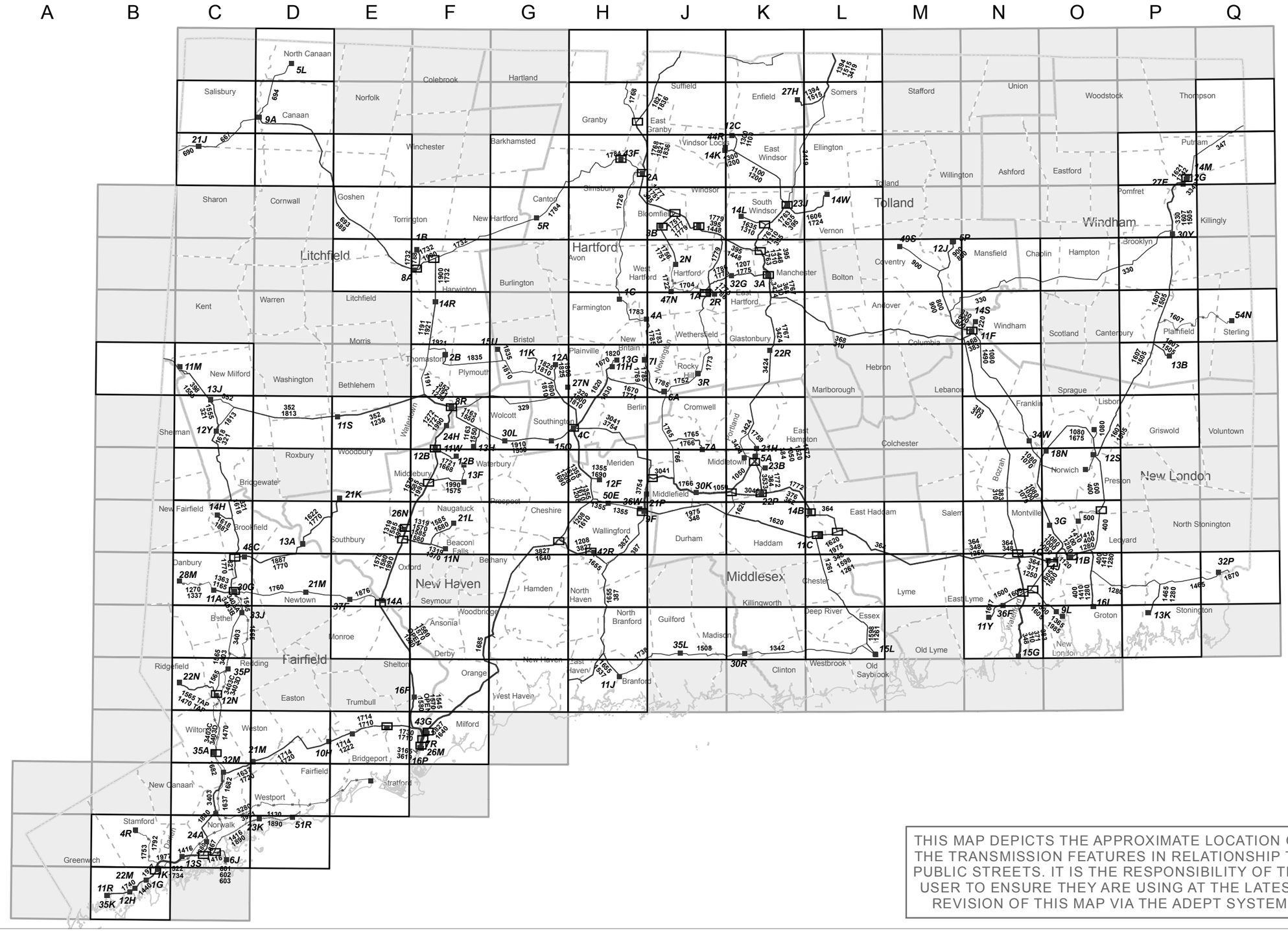
APPENDIX 2

TRANSMISSION SYSTEM MAPS

REV 0-INITIAL DOCUMENT CONTROL-DATE: 04/09

NU STING AND PERMITTING DEPARTMENT MUST BE CONTACTED IF ANY WORK IS PERFORMED WITHIN THE NDDB AREAS SHOWN.

STRUCTURE NUMBERS SHOWN MAY BE INCORRECT DUE TO RENUMBERING. FIELD VERIFICATION MAY BE NECESSARY.



THIS MAP DEPICTS THE APPROXIMATE LOCATION OF THE TRANSMISSION FEATURES IN RELATIONSHIP TO PUBLIC STREETS. IT IS THE RESPONSIBILITY OF THE USER TO ENSURE THEY ARE USING AT THE LATEST REVISION OF THIS MAP VIA THE ADEPT SYSTEM.

LEGEND

STATION	STEEL POLE	NATURAL DIVERSITY DATABASE (NDDB) - 12/01/2010	
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U.G. LINE	LATTICE TOWER		
AERIAL MARKER SPHERE	MICROWAVE		
AERIAL LINE MARKER	TOWER LIGHT		
AERIAL DIRECTION MARKER	P.C.S. ANTENNA		

TRANSMISSION LINE KEY MAP
NORTHEAST UTILITIES
THE CONNECTICUT LIGHT & POWER CO.

NOT TO SCALE

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345kV
115kV
69kV

(MX) MOBILE XFMR CONNECTION
(G) GENERATING CAPACITY

Northeast Utilities Service Co.

NU SYSTEM DIAGRAM

BY	REV. NO.	DATE	SIZE	DWG. NO.
KPKR	5	8/14/09	B	29600–30005 PG. 1

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345kV
115kV
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(MX) MOBILE XFMR CONNECTION
(G) GENERATING CAPACITY

Northeast Utilities Service Co.

NU SYSTEM DIAGRAM

BY	REV. NO.	DATE	SIZE	DWG. NO.
KPKR	5	8/14/09	B	29600-30005 PG. 2

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APPENDIX 3

SPECIFICATION FOR LOCAL DISTRIBUTION LINE CLEARANCE TREE WORK AND BRUSH CONTROL

Northeast
Utilities System

SPECIFICATION

for

LOCAL DISTRIBUTION

LINE CLEARANCE

TREE WORK and BRUSH CONTROL

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2010

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Northeast Utilities
Specification for Local Distribution
Tree Work and Brush Control

1. General Requirements

This document describes the scope of work and technical requirements for the Northeast Utilities Distribution Line Clearance Program. All work shall be performed by qualified line clearance contractors. Safety shall take precedence over all requirements described herein and at no time shall work be performed in an unsafe manner.

- All contact with the public and government officials shall be done in a courteous manner.

- Work shall be subject at all times to inspection by NU and government officials. The crew foreman, or the contractor's designee, shall notify NU of the crew's daily work location and of any change made during the day.

- Work shall be performed in such a manner that it will not interfere with or affect in any way the operation of any existing energized lines or electrical equipment, except as specifically directed by NU.

- All line clearance work shall be performed in strict accordance with all applicable federal, state and local governmental laws and regulations or approved standards and safety practices – ANSI A300 (Part 1)-2001, Best Management Practices – Utility Pruning of Trees, ANSI Z133.1-2006, OSHA 29 CFR 1910.269. The contractor shall be responsible for the knowledge, supervision and enforcement of them.

- When necessary, the contractor requests permission from tree owners and others to perform line clearance tree work around electrical conductors. Where the tree owner is not at home, use the appropriate permission card and customer brochure. For all refusals, light trims or no contacts the contractor shall fill out a copy of form OP5520, DISTRIBUTION LINE CLEARANCE PERMISSION REFUSAL/LIGHT TRIMMING and submit the form weekly.

- The crew foreman shall complete a WEEKLY DISTRIBUTION TREE OR BRUSH CONTROL REPORT adding information daily for all T&M work. The report shall be submitted to NU no later than Tuesday of the week following the completed work week.

- The line clearance crew shall work progressively along the distribution system, as directed by NU, and shall complete all work on a given portion

of the line before starting work at another location, unless otherwise approved by NU.

- Retrimming will be required to correct all situations where trimming quality is determined by NU to be improper.

- Climbing irons shall not be used in any tree unless the tree is to be removed.

- Wherever NU is solely responsible for clean-up (as differing from NU special instructions where a public authority or property owner or his agent has agreed to clean-up), normally it shall be completed daily and the site shall be left in at least as neat and orderly condition as it was found.

2. Scope of Work

This Specification covers the trimming and removal of trees and brush, including the use of herbicides for brush control along rural and urban overhead electrical lines and around substations owned or used by Northeast Utilities. This includes clearing for existing lines as well as for new lines, and applies to local distribution only, along and off-roads, and not bulk supply distribution rights-of-way.

2.1. Scheduled Maintenance Trimming (SMT)

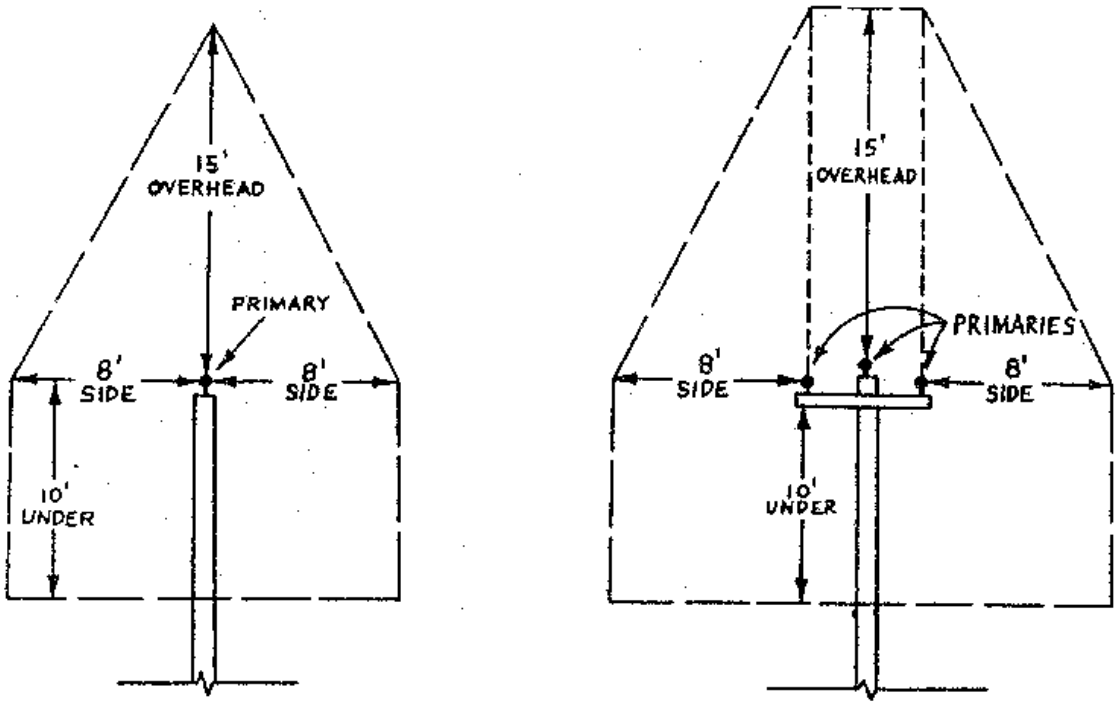
2.1.1. Primary Conductors

Conductor clearances relative to various primary wire positions are shown in Figure 1. Each tree must be evaluated on its own at the time it is trimmed. The tree crew must consider the variables including tree species, condition, growth rate and location.

Watersprouts and suckers shall not be trimmed, they shall be removed back to the originally established clearance level.

Figure 1

CLEARANCE ZONE DIMENSIONS
for
PRIMARY VOLTAGE CONDUCTORS (2.4 to 34.5 kV)



The 15 feet overhead clearance shall be measured vertically upward from the highest primary.

The 8 feet side clearance shall be measured horizontally outward from the outermost primary.

The 10 feet under clearance shall be measured vertically downward from the lowest primary.

Normally, remove all branches within the clearance zone bounded by the dashed line perimeter and all overhead hazards within reach of a 55' aerial lift.

If the existing clearance is less than the required clearance between tree trunk or large (>= 6 inches in diameter), healthy limb (with strong crotch) and wires, leave them and remove all other branches within the clearance zone.

2.1.2. Service Drops and Secondaries Without Primaries Above

2.1.2.1. Triplex

Do not clear around them unless authorized by NU. When approved, trim only limbs in contact with the conductor. Trimmed branches shall provide 2 feet of clearance around all conductors.

2.1.2.2. Open Wire Secondary

Do clear, trimmed branches shall provide 2 feet of clearance around all conductors.

2.1.3. Tree Removal

Remove all hazard trees up to and including 16 inches DBH within 8 feet of the outermost conductor. The removal of any tree greater than 16 inches DBH must be approved by NU. NU will provide specific instructions in each case depending upon whether others are sharing the cost or disposing of the tree parts.

2.2. Enhanced Tree Trimming

2.2.1. Fall Zone Hazard Tree Management

- Inspect, evaluate and eliminate all hazardous trees within the fall zone by pruning or removal.

2.2.2. Roadside Clearance Zone

2.2.2.1. Lateral

Prune and remove all overhead hazards and provide a minimum of 20 feet of overhead clearance above primary conductors.

2.2.2.2. Backbone

Prune and remove all overhead limbs.

2.2.2.3. Side and Under Clearance and Brush Removal

Prune to provide 8 feet of side clearance and 10 feet of under clearance around primary conductors. Flat cut all brush. Cut vines on all poles and guy wires.

2.3. Maintenance Enhanced Tree Trimming

2.3.1. Lateral

Prune to provide a minimum of 20 feet of overhead clearance above primary conductors.. Remove all overhead hazards within reach of a 55 foot aerial lift.

2.3.2. Backbone

Re-clear to the previously established ETT clearances including new growth into the clearance zone. Remove all overhead hazards within reach of a 70 foot aerial lift.

2.3.3. Side and Under Clearance and Brush Removal

Prune to provide 8 feet of side clearance or to the previously established tree line and 10 feet of under clearance around primary conductors. Flat cut all brush. Cut vines on all poles and guy wires.

2.3.4. Hazard Tree Management

Remove hazard trees up to 16 inches DBH within 8 feet of the outermost conductor.

2.4. Mid-Cycle Trimming

Inspect and evaluate tree conditions along the entire back bone section of line scheduled. Prioritize pruning and removals based on tree conditions and likelihood of a tree causing an outage prior to the next scheduled routine trim. Where necessary:

- Remove hazard trees within the fall zone.
- Prune and remove all overhead hazards.
- Cut vines on all poles and guy wires.

- Prune trees to establish a minimum clearance of 8 feet to the side, 10 below and 15 feet above the primary conductors

2.5. New Business and Capital Construction

Remove all tree species in a strip centered on the pole line 8 feet to either side of the outermost conductors.

Provide hazard tree removal as specified in article 2.2.1 and clearance as specified in article 2.1.1 for laterals and 2.2.2.2 for backbones.

3. Pruning

Prune and remove limbs in all trees that are not scheduled to be removed. Remove overhead hazards. Pruning shall be performed in accordance with ANSI A300 standards and the Best Management Practices – Utility Pruning of Trees.

4. Tree Removal

- Contractor shall not "top" trees unless authorized by the Owner's Representative. Normally, these trees will be removed.

- Any tree which would, after trimming to clearance, be left with less than 66% of its original leaf area shall be removed. Trees greater than 16 inches DBH shall be removed only after authorization from the Owner's Representative.

- Specific instructions on billing of T&M removals, depending upon whether others are sharing the cost will be provided by the Owner's Representative.

5. Stumps

All stumps shall be cut as close to the ground as possible, and in no case shall they be cut higher than 3 inches unless used as supports for a fence or approved otherwise by NU. If certain trees serve as fence supports, they shall be cut no higher than 2 inches above the fence. All stumps shall be cut off parallel to the ground to avoid leaving sharp points on the stumps.

Normally, sproutable cut-off stumps (all hardwoods, pitch pine and vines) shall be treated with an NU approved herbicide mixture in accordance with label directions and regulatory requirements.

6. Brush and Vine Removal

All tree stems less than 6 inches DBH shall be considered brush. Brush shall not be trimmed or topped. The width of the brush removal area shall be 8 feet on each side of the outermost conductor. Flat cutting or selective brush removal shall be approved by NU.

Cutting of tree brush and woody vines shall be done with care to minimize damage to non-interfering shrubs such as the following that are permitted to remain:

Pinxterbloom Azalea	Hazelnut
Highbush Blueberry	Gray Dogwood
Redosier Dogwood	Huckleberry
Oldfield Common Juniper	Spicebush
Sweetfern	Mountainlaurel
Bayberry	Rhododendron

6.1. Flat Cutting Brush

Remove all brush that is capable of growing tall enough to touch the primary conductors.

6.2. Selective Brush Removal

Selectively remove only that tree brush which is presently at or above the height of the telephone conductor(s). Where no telephone conductor exists, tree brush 16 feet tall and over shall be removed.

6.3. Vines

All woody vines which are growing up poles or guy wires shall be cut at the ground line and cleared for 3 feet up the pole or guy.

7. Wood and Chip Disposal

The contractor shall make every effort to minimize the amount of wood and wood chip disposal that requires hauling away from the site. This can be accomplished by; making agreements with property owners to leave logs and larger limbs at the site for use as firewood, blowing chips onto the ground in rural and unimproved natural locations, and offering chips to property owners for use as mulch. All debris shall be disposed in accordance with all local laws and regulations.

The tree contractor shall not sell any unwanted logs or chips directly from his trucks during the normally scheduled work day.

The contractor shall not leave cut-off brush overnight except on off-road sections.

7.1. Chips

Smaller limbs, branches, or cut-off brush shall be chipped, normally by chipping into a truck mounted dumping chip box. However, at unimproved natural locations, chips may be blown upon the ground provided that the depth of fresh chips shall be no greater than 3 inches. Limited brush piling may be done along the edges of off-the-road pole lines, either method being subject to the land owner's approval.

7.2. Logs

Logs from the tree trunks and larger limbs shall be cut into mutually agreed or convenient handling lengths. No logs shall be split.

7.3. Debris disposal

The tree owner shall be given first preference to utilize logs and/or chips. This agreement shall be made at the time of the permission request.

7.3.1. Chips

Where chips cannot be left on site, they shall be delivered to the nearest appropriate disposal space.

7.3.2. Logs

Logs shall be left at the work site in a safe location, not to pose a hazard to anyone, for a maximum of 7 days, during which time they will be available for anyone to pick up. Any logs remaining after 7 days shall be delivered to the appropriate disposal site.

8. Substation Perimeter Clearing

This section describes how tree and brush work shall be performed around substations. Prior to beginning any work around a substation, NU personnel will provide site specific guidelines to the contractor. At no time shall contractor personnel enter the fenced area of the substation without an NU approved escort.

8.1. Brush removal

8.1.1. Non-visually sensitive or non-landscaped substations

Cut and remove all brush within 10 feet of the substation fence. If the land adjacent to the substation fence slopes toward the fence, the cleared area shall be 20 feet.

8.1.2. Visually sensitive or landscaped substations

Clear as far away from the fence as practical as directed by the NU representative.

8.2. Pruning

Trim back all branches that touch or overhang the fence. Minimum clearance shall be 5 feet to the side and 10 feet over the top of the fence.

8.3. Ornamental Screens

Ornamental trees and shrubs (arborvitae, hemlock, white pine, yew, etc.) that have been planted to provide a visual screen of the substation shall not be removed. If necessary, shearing shall be performed as directed by the NU representative.

8.4. Stump treatment

All stumps from trees and brush that have been removed and are capable of resprouting shall be herbicide treated with an appropriate herbicide as directed by the NU representative.

8.5. Cleanup

Remove and dispose of all trimmings and removal debris away from the job site unless directed otherwise by NU. The site shall be left in at least as neat and orderly condition as it was found.

9. Definitions

ANSI A300 (Part 1)-2001 Pruning – American National Standard for Tree Care Operations – Tree Shrub, and Other Woody Plant Maintenance – Standard Practices (Pruning)

ANSI Z133.1-2006 – American National Standard for Arboricultural Operations – Safety Requirements.

Backbone – a three phase section of line starting at a substation and extending to the first fused device or single/double phase reclosing device.

Brush - Tree species with a DBH of less than 6 inches. Occasionally, shrub species are considered as brush, if they have to be removed for line clearance or access.

Clearance - The distance between vegetation and conductor.

Clearance zone – The area within 8, 10 and 15 feet for laterals, within 8,10 and 20 feet for lateral enhanced and 8, 10 and clear overhead for backbones.

Contractor - The business or employees of that business, that has contracted with Northeast Utilities to perform line clearing.

DBH - Diameter Breast Height - Diameter of a tree measured at a point 4 1/2 feet above ground.

Fall Zone - The area including the roadside clearance zone and extending from the conductors out a distance to where an uprooted tree could strike the conductor and cause an outage.

Hazard tree – Any tree that is dead or, after evaluation using the ISA's A Handbook of Hazard Tree Evaluation for Utility Arborists, rates as a moderate or high hazard.

Lateral – a section of primary voltage line extending from the end of backbone to a secondary or service wire.

Line Clearing - Controlling vegetation to maintain proper clearance from conductors which includes tree trimming, removal, topping, and brush and woody vine removal.

NU - Northeast Utilities Service Company or The Connecticut Light & Power Company or Public Service of New Hampshire or Western Massachusetts Electric Company employee who is the Northeast Utilities representative.

OSHA – Occupational Safety and Health Administration.

Overhead hazards – dead, dying, diseased, insect infected and structurally weak branches including those which could break at weak points and strike conductors when swinging down in an arc.

Refusal – A refusal is when a property owner does not allow any trimming to be performed. A light trim is when the property owner allows some trimming but does not allow the contractor to trim for the required clearances.

Shrub - A woody plant normally maturing less than 20 feet in height and presenting a generally bushy appearance because of its several erect, spreading or prostrate stems.

Stump Treatment - Herbicide applications made to sproutable cut-off stumps (all hardwoods and Pitch Pine) in order to prevent the stump from sprouting.

Substation - An electrical facility that receives electricity at high voltages and reduces the voltage so that it can be passed on to customers at a lower voltage.

Tree - A woody plant normally maturing at 20 feet or more in height, usually with a single trunk, unbranched for several feet above ground, with a definite crown. It shall have a DBH of 6 inches or greater.

T&M – Tree work performed at Time and Material billing rates. Work is recorded on the Weekly Distribution Tree or Brush Control Report using labor and equipment codes approved by NU's Purchasing Department.

Wires/Lines/Conductors - The overhead wires which carry the electric current at required voltages. Also to be considered for tree clearance and safety are other pole mounted equipment such as transformers, fuses, circuit breakers, etc.

Wire types –

Primary - A wire running from pole to pole operating at a voltage level exceeding 600 volts (2400 to 34500 volts on the NU overhead System), and normally located at the top of a pole.

Secondary - A wire running from pole to pole operating at a voltage level of 600 volts or less (normally 120 to 240 volts on the NU overhead System), and normally located approximately 4 feet below the pole top.

Triplex - Two insulated wires in a twisted configuration around a bare neutral wire.

Open Wire Secondary - Three parallel wires normally in a vertical configuration separated from each other by a few inches.

Service Drop - The secondary wires connecting the point of attachment on the premises being served to the nearest pole of the distribution system.

APPENDIX 4

TABLE OF INSPECTION AND MAINTENANCE FREQUENCIES

APPENDIX 4
TABLE OF INSPECTION AND MAINTENANCE FREQUENCIES

Ref. No.	Types of Equipment/Procedure	Frequency Now	Frequency Prior	Remarks
1.	Inspection of DB Facilities	5 Year	No Change	
2.	Capacitor Bank			Inspected after winter. Repaired prior to summer load period.
	Pole Top	Annual Insp.	No Change	
	Substation	Monthly	Annually	
3.	Inspect & Maintain Pole-top Voltage Regulating Equipment	1 Year As Required	No Change	Company experience has proven that a 1-year interval is sufficient for keeping this equipment reliable. Major Maintenance based on inspection results
4.	Inspect, Test, and Maintain Reclosers			
	SCADA Controlled	Annually	No Change	Additional equipment checks are performed following storms and line faults.
	Non SCADA Controlled	Bi-Monthly	No Change	
	Substation	Monthly	No Change	
5.	Network Transformers	Annually	No Change	Routine Maintenance Inspection
	Protectors	2 or 4 Years	No Change	Major Maintenance/Frequency dependant on model # of protector
6.	Underground Cable	5 Year	No Change	Coincident with other underground equipment maintenance
7.	Street Lights in Underground Areas	5 Year	No Change	Coincident with other underground and direct buried system equipment inspections.
8.	Infrared Inspection	Annually	No Change	3-phase circuit backbone and associated pole mounted reclosers, sectionalizers, 3-phase regulators, capacitors and switches.
9.	Distribution Wood Pole Insp. & Treat.	15 Year	No Change	
10.	3-Phase Group Operated Switches	6 Year	No Change	

APPENDIX 4
TABLE OF INSPECTION AND MAINTENANCE FREQUENCIES

Ref. No.	Type of Equipment/Procedure	Frequency Now	Frequency Prior	Remarks
11.	Underground Transformers	5 Year	No Change	Coincident with other underground equipment maintenance
12.	Customer Vaults & Manholes	5 Year	No Change	Coincident with the Company owned equipment maintenance frequencies or every 5 years, whichever comes first.
13.	Corrosion- Anodes	See Remarks	No Change	Coincident with other underground system inspections.
14.	Cyclic Circuit (Feeder) Management	15 year	No Change	

APPENDIX 5

INSPECTION OF DIRECT-BURIED FACILITIES

Inspection of Direct Buried (DB) Systems

General Description – NUMM 5.11

This procedure defines the schedule, inspection, and the reporting requirements for the inspection of Direct Buried facilities. Periodic inspections of Direct Buried and associated equipment allows preventative and corrective actions to be performed prior to situations becoming hazardous to the public or resulting in equipment failure. The inspection covers items such as stray voltage, required signs and labels, corrosion, discovery of oil leaks, and vegetation clearing. Inspection of a portion of all equipment each year ensures that all equipment is inspected in a reasonable period of time and corrective actions taken by appropriate departments.

See NUMM instruction 6.11 for details on performing the DB Inspection

Facilities/Equipment

Company-owned direct-buried facilities including:

- Pad-Mounted Transformers
- Submersible Transformers
- Switch Enclosures
- Switchgear
- Transclosures
- Handholes (HH)
- Pull Holes
- Risers
- Fault Indicators
- Primary and secondary cable

Conditioned Based

Repair or replace any defective components found during the DB routine inspection if possible, or note repairs that cannot be completed during the routine inspection for future correction.

Failure Finding

Perform any necessary repairs or correct any conditions as required and document the repairs or corrections made. Failures of any major DB equipment shall be documented in the equipment failure reporting system used by your region. Minor deficiencies (e.g premature paint peeling on newer equipment, or misaligned doors on pad-mounted equipment) should also be reported to Distribution Standards.

Routine Inspection - NUMM 6.11

Perform each of the following inspection activities, as applicable to the equipment type and record the results/findings into current version of the appropriate form.

1. Inspect the equipment for deterioration and proper grading.
2. Ensure there are no obstructions and that the area is accessible. Record the presence of any unwanted vegetation that may obstruct the inspection or maintenance of equipment.
3. Inspect the condition of the case. Check it for internal and external rust, dents, etc.
4. Ensure standard signs, cable tags, and labels are in place and in good condition.
5. Ensure safety and security equipment (such as locks and penta bolts) are in place and in good working condition. Check for signs of vandalism.
6. Ensure electrical barriers are in place and in good condition.
7. Ensure that all grounds, neutral, and drain wire connections, such as primary, secondary, transformer, etc. are in place and in good condition.
8. Ensure that primary/secondary equipment, such as bushings, insulators, arresters, elbows, elbow arresters, terminators, connectors, cable taps, dead-end receptacles are in good condition. Check for signs of arcing, tracking, chipping, stress, etc. for all connections.
9. Inspect indicators including – temperature, oil level, fault-read, record and reset as applicable. Test fault indicators and ensure they are in good condition and working. Check fault indicator's date and replace older style indicators, if found. Ensure proper installation & verify 2.5" min. spacing to ensure proper operation.
10. Ensure protective bumpers are in place and in good condition. Replace damaged ones as required.
11. Inspect the Pit/handhole (cable) for silt, debris, or erosion.

12. Ensure the transformer/enclosure is set properly on its concrete slab/pad.
13. Inspect equipment for signs of oil leaks.
14. Ensure all covers or grates are securely locked or bolted in position.
15. Ensure deflectors plates are installed, as required for the specific equipment type.
16. Use the equipment prints/schematics to verify the actual field conditions, i.e., transformer size, etc.
17. Check the mounting hardware to ensure it is stable and free from corrosion.
18. Inspect vegetation for intrusion into the equipment.
19. Inspect the general condition of the riser and ensure it is secured to a pole.
20. Ensure riser pole stencils are present and that the stenciled fuse size agrees with that on the DB map.
21. Inspect elbow arrestors are present and in good condition, as required.
22. Ensure switchgear covers are in place and are in good condition. Details for performing switchgear maintenance are provided in a separate chapter.
23. Install secondary bushing covers, as applicable. Some configurations will not support their installation due to the large number of secondary conductors connected to the bushings.
24. Perform a stray voltage test on all equipment at risk, metal light poles, metal HH covers, grating, boxes, etc.
25. Performa an infrared inspection on elbows and secondary connections at pad-mounted transformers, if warranted by local conditions.

- **Note any conditions that require follow-up repair.**

Replace Fault Indicators

Replace fault indicators at a ten year interval

APPENDIX 6

CAPACITOR BANK INSPECTION

Capacitor Banks

General Description – NUMM 5.05

Banks of capacitors are used to improve the power factor on the system. Other benefits include reducing system losses and improved voltage control. Capacitors are voltage sensitive, and will not tolerate an extended over voltage condition of more than 110 percent of the nameplate rating without deterioration and eventual failure. Because of their electrical characteristics, they are susceptible to large inrush currents, discharge currents, and transient voltage peaks, each of which can reduce the expected life of the individual capacitor or increase the equipment servicing requirement of the bank.

Capacitors store energy in the form of electrical charge. They are designed with internal resistors that are intended to discharge to 50 volts within 5 minutes after disconnection from the voltage source. It is important to allow this period to expire before applying grounds to a de-energized capacitor bank, in order to prevent damage and/or hazards resulting from high discharge currents. Note that newer capacitors have discharge resistors, but older ones may not. Check the Capacitor breaker with an approved audible tester.

Capacitor banks are applied within substations and on poles on the distribution system. Substation capacitor banks are made up of one or more series groups of capacitor cans often connected in parallel. Individual capacitors are normally provided with fuses. A blown fuse may be a sign of a failed capacitor. Since this could result in poor operation of the bank and/or damage to other capacitors within the bank, any capacitor with a blown fuse should be tested. Any capacitor suspected to be damaged (i.e., bulged tank, partial shorting per test results, etc.) should be replaced prior to re-energizing the bank. Failed capacitors must be handled carefully, due to the possible presence of gasses under pressure.

Capacitor Banks can be switched or not switched. Capacitor switches are devices that require periodic maintenance. For information on servicing capacitor switches, see the chapters on Circuit Switchers and Oil & Vacuum Switches.

Pole-Top capacitor banks are generally protected by fused cutouts. As with substation banks, a blown fuse may indicate a failed capacitor unit.

Pole-Top capacitors require little maintenance. Scheduled inspections should be made before the heavy load season (typically from November to March) to ensure the equipment is operating properly. The components to inspect include capacitor cans, cutouts, oil switches, vacuum switches, arresters, control settings, control and radio batteries, and grounding.

Capacitor fuse(s) often blow with no visible damage, or indication of failure, of the capacitor. Failure of the newer all-film capacitors are particularly hard to discern since they generate considerably less gas than paper-film capacitors.

Facilities/Equipment

- Substation Capacitors – Rack-Mounted or Metal-Enclosed
- Pole-Top Capacitor Banks

Capacitor Maintenance – **NUMM 6.05**

Routine Check – Energized – Substation

Rack Mounted Units

1. Check the fence enclosure, warning and caution signs, and locks for proper installation and condition (if applicable).
2. Visually check all fuses.
3. Check for oil leaks.
4. Visually check the condition of each capacitor.
5. Visually check for objects or animals/birds' nests on the capacitors and on the rack.
6. Visually check any associated primary connected equipment (i.e., switches, lightning arresters, reactors) for abnormalities.
7. Visually check the breaker or interrupter counter(s) for normal operation without cycling the equipment.
8. Visually check the controls (i.e., voltage, current, time clock, radio and lights) for proper operation without cycling the equipment.
9. Listen for unusual noises.
10. Check the condition of the control cable, if possible.
11. Record the operations counter reading and other conditions pertinent to the unit (i.e., targets, fuses).

Metal – Enclosed Units

1. Visually check the enclosure for damage and security (i.e., proper locking, unrestricted ventilation, signs of animal entry).
2. If the breaker, switch, or interrupter is safely accessible, visually check the condition and counter for normal operation without cycling the equipment.
3. Check the condition of the control cable, if possible.
4. Visually check the controls (i.e., voltage, current, time clock, radio and lights) for proper operation without cycling the equipment.

5. Record the operations counter reading and other conditions pertinent to the unit (i.e., targets, fuses).
6. Check for oil leaks, if possible.
7. Listen for unusual noises.

Major Inspection – De-Energized – Substation

NOTE: Prior to beginning maintenance, ensure that all switching and notifications are performed in accordance with Company requirements.

Metal-Enclosed Units Only

Isolate and ground the capacitor bank using appropriate operating and safety procedures (allow 5 minutes before grounding bank after isolation).

1. Remove the capacitor bank from service in accordance with Company requirements.
2. Visually inspect the bank for the following:
   - Bulging cans
   - Oil leaks
   - Cracked housings
3. Check the ground switch and interlocking mechanism for damage or abnormalities.
4. Open all compartment doors and check for water leaks, oil leaks, moisture, and contamination.
5. Check for foreign material or signs of animal entry. If an opening exists that may allow entry, repair or safely block the opening before returning the bank to service.
6. Check the condition of ventilators and filters.
7. Check the fans and thermostats, if applicable, for proper operation.
8. Check all fuses.
9. Check all capacitor tanks and connections for abnormalities.
10. Clean the unit before re-energizing if it is dirty.
11. Remove Worker's grounds and short circuits from the bushings, if installed.
12. Disconnect the phase jumpers between the capacitor cans, if installed.
13. Test any capacitors found to have blown fuses as follows:
    a). Review the capacitance meter manufacturer's instructions.
    b). Calibrate the capacitance meter.
    c). Connect test leads to capacitor-can bushings.
    d). Ensure good test lead connection.
    e). Measure the capacitance of each capacitor can. See Appendix 1 for acceptable test values. Fail any can that tests outside of these values.

NOTES:

- Acceptable capacitance readings and a satisfactory visual inspection are indications of a good capacitor can.
- The capacitance meter test may not always be correct. A failed capacitor may read within the range which that indicates that the capacitor is good. Because this is not a conclusive test, every precaution shall be taken when energizing a capacitor.

14. Refer to Appendix 1, Capacitor Test Benchmarks and the following to determine if the capacitor can(s) are acceptable:
    a) Compare test results to the indicated values for the size and voltage of the can.
    b) Refer to Appendix 1 and verify the meter reading is within the acceptable range specified by upper and lower limits.
    c) If the capacitance meter reading is outside of the acceptable range specified by the upper and lower limits, identify the cans as failed.
15. Replace failed capacitor can(s) if visual inspection and/or capacitance test results indicate capacitor can failure(s). Refer to TD 832, "Capacitor Bank Inspection".
16. Restore the capacitor bank to service in accordance with Company requirements.
17. Check the operation of the oil switches when initiating a close (to re-energize the bank).

Major Test – De-Energized – Substation

Rack-Mounted and Metal-Enclosed Units

1. Test the voltage, current, time and/or radio operating contrls for proper operation; check and verify their settings

NOTE: Prior to performing the remainder of this maintenance, ensure that all switching and notifications are performed in accordance with Company requirements.

2. Isolate and ground the capacitor bank using appropriate operating and safety procedures. Allow 5 minutes before grounding the bank after isolating it.
3. Remove the capacitor from service in accordance with Company requirements.
4. Visually inspect the bank for the following:
    - Bulging cans
    - Oil leaks
    - Cracked housings

5. Open all compartment doors and check for water leaks, oil leaks, moisture, and contamination.

6. Check for foreign material or signs of animal entry. If an opening exists that may allow entry, repair or safely block the opening before returning the bank to service.
7. Check the condition of ventilators and filters.
8. Check the fans and thermostats, if applicable, for proper operation.
9. Operationally check all associated switches and interlocking mechanisms (disconnect, ground, vacuum, etc).
10. Wipe clean all insulators, bus supports, fusses, and bushings.
11. Check all capacitor tanks and connections to ensure that connections are tight and that there are no abnormalities.
12. Visually check and verify proper fusing of capacitors.
13. Check for blown fuses.
14. Test any capacitors found to have blown fuses as follows:
    a) Review the capacitance meter manufacturer's instructions.
    b) Calibrate the capacitance meter.
    c) Connect test leads to capacitor-can bushings.
    d) Ensure good test lead connections.
    e) Measure the capacitance of each capacitor can. See Appendix 1 for acceptable test values. Fail any can that tests outside of these values.

NOTES:

- Acceptable capacitance readings and a satisfactory visual inspection are indications of a good capacitor can.
- The capacitance meter test may not always be correct. A failed capacitor may read within the range that would indicate that the capacitor is good. Because this in not a conclusive test, every precaution shall be taken when energizing a capacitor.

15. Refer to Appendix 1, Capacitor Test Benchmarks and the following to determine if the capacitor can(s) are acceptable:
    a) Compare test results to the indicated values for the size and voltage of the can.
    b) Refer to Appendix 1 and verify the meter reading is within the acceptable range specified by upper and lower limits.
    c) If the capacitance meter reading is outside of the acceptable range specified by the upper and lower limits, identify the cans as failed.

16. Replace failed capacitor can(s) if visual inspection and/or capacitance test results indicate capacitor can failure(s). Fefer to TD 832, “Capacitor Bank Inspection”.
17. Clean the unit before re-energization, if it is dirty.
18. Restore the capacitor bank to service in accordance with Company requirements.
19. Check the operation of the oil switches when initiating a close (to re-energize the bank).

Major Maintenance – De-Energized – Substation

Rack-Mounted and Metal-Enclosed Units

1. Test the voltage, current, time and/or radio operating controls for proper operation; check and verify their settings.

NOTE: Prior to performing the remainder of this maintenance, ensure that all switching and notifications are performed in accordance with Company requirements.

2. Isolate and ground the capacitor bank using appropriate operating and safety procedure (allow 5 minutes before grounding bank after isolating).
3. Remove the capacitor from service in accordance with Company requirements.
4. Visually inspect the bank for the following:
    - Bulging cans
    - Oil leaks
    - Cracked housing
5. Open all compartment doors and check for water leaks, oil leaks, moisture, and contamination.
6. Check for foreign material or signs of animal entry. If an opening exists that may allow entry, repair or safely block the opening before returning the bank to service.
7. Check the condition of ventilators and filters.
8. Check the fans and thermostats, if applicable, for proper operation.
9. Test the voltage, current, time and/or radio operating controls for proper operation; check and verify settings. (If the bank is de-energized, it may not be possible to functionally check the controls. Functional check of a bank should be done prior to switching it out. This will allow for repairs to the controls while the bank is out).
10. Operationally check all associated switches and interlocking mechanisms (disconnect, ground, vacuum, etc).
11. Wipe clean all insulators, bus supports, fuses, and bushings.
12. Check all capacitor tanks and connections to ensure that connections are tight and that there are no abnormalities.
13. Visually check and verify proper fusing of capacitors.
14. Check for blown fuses.

15. Test any capacitors found to have blown fuses as follows:
    a) Review the capacitance meter manufacturer's instructions.
    b) Calibrate the capacitance meter.
    c) Connect test leads to capacitor-can bushings.
    d) Ensure good test lead connection.
    e) Measure the capacitance of each capacitor can. See Appendix 1 for acceptable test values. Fail any can that tests outside of these values.

NOTES:

- Acceptable capacitance readings and a satisfactory visual inspection are indications of a good capacitor can.
- The capacitance meter test may not always be correct. A failed capacitor may read within the range which would indicate that the capacitor is good. Because this is not a conclusive test, every precaution shall be taken when energizing a capacitor.

16. Refer to Appendix 1, Capacitor Test Benchmarks and the following to determine if the capacitor can(s) are acceptable:
    a) Compare test results to the indicated values for the size and voltage of the can.
    b) Refer to Appendix 1 and verify the meter reading is within the acceptable range specified by upper and lower limits.
    c) If the capacitance meter reading is outside of the acceptable range specified by the upper and lower limits, identify the cans as failed.
17. Replace failed capacitor can(s) if visual inspection and/or capacitance test results indicate capacitor can failure(s). Refer to TD 832, "Capacitor Bank Inspection".
18. Clean the exterior of the capacitor can, if it is dirty.
19. Test the breaker, interrupters, or switches as directed in their individual sections if on cycle with this work activity.
20. Replace any faulty equipment prior to returning the capacitor bank to service.
21. Restore the capacitor bank to service in accordance with company requirements.
22. Check the operation of the oil switches when initiating a close (to re-energize the bank).

Pole-Top Capacitor Maintenance

Time-Directed

Pole-Top Capacitor Inspection

1. Visually inspect the bank for the following:
   - Bulging cans
   - Oil leaks
   - Cracked or broken bushings, if possible
   - Loose connections, if possible
   - Blown fuses
   - Blown arresters
   - Grounds and grounding connections
   - Damage reactor coiling.

2. Record the operations counter reading.
3. Verify that all control switches are in their normal positions.
4. Schedule a replacement of the capacitor can if any obvious problems are found, such as physical damage, etc.
   - If a fuse is blown, test the capacitor.
5. From capacitor control, record the voltage, KVAR and Power Factor. (Note: this information may not be available on some controls). Initiate a close. The recorded values should have changed because of the added capacitance.

NOTES:

- A satisfactory visual inspection is an indication of a good capacitor can only.
- If the capacitor is not functional and has oil switches, the bank should be replaced with new.

Failure Findings:

1. See Appendix 2 for a matrix to be used for determining when to replace capacitors based on inspection findings and maintenance history.
   - ***Replace*** the entire capacitor bank (see Appendix 2)
     - If there have been three or more can failures on the capacitor bank.

    - If there have been more than two trips to the capacitor bank for repairs other than Cans and Switches.
    - If the capacitor is not functional and has oil switches.
- ***Repair*** the capacitor bank if none of the above conditions for replacement exist (See Appendix 2).

APPENDIX 7

POLE-MOUNTED, THREE-PHASE, GROUP OPERATED SWITCHES

Disconnect Switches

General Description - NUMM 5.15

Switches are essential elements of the electrical power distribution systems. They provide positive, visible air gap isolation of equipment and line sections for safe examination, maintenance, and repair. Switches are built in a variety of physical forms to accommodate the various requirements of electrical clearances, operational requirements, and space limitations. They can be divided into three main categories:

- Regulator Bypass switches
- Disconnect switches
- Interrupter switches

REGULATOR BYPASS SWITCHES

Bypass switches are generally used at regulator installations to provide a quick, reliable means of taking such apparatus in and out of service without de-energizing the feeder circuits and to prevent winding burnouts from open-circuit windings.

DISCONNECTS – Single Phase Switches (not including fused cutouts)

There are two general classifications for disconnect switches:

- Loadbreak and
- Non-loadbreak

Loadbreak disconnects may be used to make or break current up to the ampere rating of the switch/Load Buster tool combination.

Non – Loadbreak disconnects are rated for use as a means to energize or de-energize:

- Unloaded bus or bus segments only within the substation
- Unloaded circuit breakers, lightning arresters, and other switches.

and under certain circumstances, may be used to make or break a parallel connection to another switch.

All overhead and some substation disconnects include a loadbreak hooks for use with a loadbreak tool. To open the switch under load, use only an approved loadbreak tool or device designed for use with switches. Follow the instructions provided with the loadbreak tools.

INTERRUPTER SWITCHES – Gang-Operated Disconnects (GOD) sometimes referred to as Gang-Operated Air Brake (GOAB)

Gang-operated disconnects are used where more than one phase of a circuit must be opened simultaneously. The most common gang-operated disconnect switches are the air-brake type manufactured with up to 1200-ampere ratings in voltage classes up to 46 kV. They are used at substations, switching structures, and on the lines for energizing and de-energizing transformer banks and other apparatus. They are also used for sectionalizing. Although they can be MODs (Motor-Operated Disconnects), they are more commonly provided with a switch handle for hand operation. This type of switch is ideal because it lends itself to operation from the ground, often permitting service to be restored to sections of the circuit without pole climbing.

Although there are distinctions between the three categories of switches, for the purpose of simplicity, they will be collectively referred to as "disconnects", in the remainder of this procedure.

Motor Control – Some three phase group-operated disconnects are equipped with electric motors to open or close them. These disconnects may be operated remotely.

SCADA – Some disconnect switches are connected to SCADA – an automated system that monitors the switch position, current and voltage and provides the data to a remote location. It also allows for remote operation of the switch if the switch is motor operated.

Scadamate – A three phase group-operated disconnect type switch with SCADA capability.

Facilities/Equipment

- Line bypass, Disconnect, and Interrupter Switches

NOTE: The inspection and maintenance for single phase Pole-top disconnects is the same for "inline suspension" disconnects.

Note 1: This inspection is performed as part of the Backbone inspection for Main Line Distribution.

Note 2: Routine Switch Controller maintenance consists of replacing battery packs. The frequency of replacement depends on designed battery life, ambient temperature, float charge voltage and frequency of discharge. Industry experience has shown that batteries should be replaced every two years for hot environments and three years for colder environments.

Note 3: A Major inspection is performed for those Substation Disconnects that are not practical to de-energize, even when the associated equipment is being maintained and is out of service. Those units that fail this inspection are replaced.

Note 4: Major Maintenance – De-Energized for Substation Disconnects (those that can be de-energized) is performed when the equipment to which it is associated is being maintained and is out of service.

Note 5: The Operational Test is performed at the time Major Maintenance.

Time – Directed Maintenance

Infrared Inspection – Energized

Due to operating criteria and mounting configurations, pole-top and inline suspension switches are not readily serviced or required to be serviced at frequent intervals. However, inspection and annual infrared scanning are recommended.

Visual Inspection – All 3 Phase Disconnects – Energized

Inspection is required at 1Y intervals, but may be performed more often due to atmospheric contamination, use of contamination control coatings, frequency of operation, fault current exposure, etc. A visual inspection of a switch when wet, or the use of a temperature-scanning detector may indicate hot spots that are possible sources of trouble.

Major Inspection – Energized

This is performed on substation manual and motor operated disconnect switches (MOD) that are not practical to de-energize. It is performed when the associated equipment is out of service for maintenance. Although energized, switches qualifying for this inspection are not carrying load (associated equipment is out of service), allowing the switch to be operated.

Major Inspection – De-Energized

Whenever the switch is operated it should be opened and closed several times, if practicable, in order to clean the contacts and free the moving parts.

Motor Control Visual Inspection/Battery Replacement

See NUMM instructions 6.15A for detail steps for three phase overhead switches and 6.15B for detail steps for substation switches.

Condition-Based

Operational Test – See NUMM instructions 6.15a for detail steps for three phase overhead switches and 6.15B for detail steps for substation switches.

Failure Finding

Failures of major disconnect switches shall be documented in the equipment failure reporting system used by your region. Analysis of disconnect switch failures should be performed when deemed necessary by Distribution Standards.

Visual Inspection – All 3 Phase Disconnects – Energized

NUMM 6.15A

1. Visually inspect the three phase disconnect switch for the following:
   - Insulators - damage
   - Frayed or broken flexible connections
   - Taps - from switch to line conductors
   - Overheating (visual)
   - Condition of operating mechanism
   - Alignment of blades and proper contact
   - Signs of abnormal discharge, alignment and tripling linkage on load breaking devices
   - Operating rod insulator for damage and proper position, or missing insulator
   - Mechanical condition of frame
   - Condition or pitting of arcing horns, if applicable
   - Conditions or grounds and ground attachments
   - Obstructions/Tree Branches that might obstruct operation or create a contact hazard
   - Debris – bird nests, kite string, etc. on switch
   - Squirrel Guards – missing or damaged, if applicable
   - Confirm all switch numbers and phase markings are installed, where applicable
   - Visually check the condition of the Lightning Arresters, if applicable
2. Record any conditions that require follow-up repair. Follow-up repairs require the initiation of a corrective work order/request.

Major Maintenance – Energized

1. Ensure that the switch is bypassed or transfer the load before performing this inspection.
2. Check the structural grounds for mechanical security.
3. Inspect the flexible braids or slipping contacts used for grounding the operating handle. Replace any braids showing signs of corrosion, wear, or having broken strands.
4. Examine the structure, mechanism enclosure and linkage for general condition.
5. Ensure mechanical locking devices are secure and in good operating condition.
6. Operate all switches several times.
7. Check the switch for smooth operation.
8. Ensure the open and close mechanical indicators are working.
9. Ensure that all Motor Operated Drive (MOD) control switches are in their normal position or are properly tagged, if applicable.
10. Check MOD red and green indicating lights, if applicable.
11. Verify that rotating blades are fully seated and rotated, if applicable.
12. Visually check the alignment of the blade and jaw on each pole and verify the blades are latched, if applicable.
13. Check the insulator for chipped or cracked porcelain, and the accumulation of dirt or other contamination deposits (bird nest, strings, etc).
14. Check the condition of arcing horns and/or whips for pitting, burning and missing parts, if applicable.
15. Verify the operation of heaters and proper operation of the thermostats, if applicable.
16. Note the position of the safety relief valve and check the indicator on switches using a vacuum or gas interrupting unit, if applicable.
17. Visually check all electrical and mechanical connections for tightness and unusual wear.
18. Check for proper pressure and air leaks on switches employing an Air Blast attachment.
19. Check for the condition and presence of all signage and phase designations, where applicable.
20. Record any conditions that require follow-up repair. Follow up repairs require the initiation of a corrective work order/request.

Major Maintenance – De-Energized

1. Disconnect the switch from all electric power sources before servicing.
2. Check for broken plastic cams on the blades
3. Inspect the insulators for breaks, cracks, burns, or cement deterioration.
    - Clean the insulators particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist. This is important as it will minimize the possibility of flashover resulting from the accumulation of foreign substances on the insulator surfaces.
    - Replace any broken or defective insulators immediately.

NOTE: The S&C disconnect switches require inspection/adjustment to ensure proper blade alignment.

4. Check the switch for alignment, contact pressure, eroded contacts, corrosion, and mechanical malfunction.
    - Replace damaged or badly eroded components.
    - If contact pitting is of a minor nature, smooth the surface with clean, fine emery cloth or as the manufacturer recommends. NOTE: Scotch Brite works well on silver contacts when a wire brush cannot be used.
    - Lubricate the contacts with a thin film of manufacturer-recommended, non-oxide grease *for non-self lubricating contacts only.*

NOTE: S&C Omni-Rupter Switch blade contacts are greaseless and self-lubricating. ***DO NOT*** apply lubricant to the blade contacts.

5. Lubricate the bearings, if applicable.
6. Check the blade latch for adjustment. Ensure the blades move freely and still are rigid enough for proper alignment with contacts.
7. Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona.
8. Inspect inter-phase linkages, operating rods, levers, bearings, etc., to ensure that adjustments are correct, all joints are tight, and pipes are not bent.
    - Clean and lubricate the switch parts, as required.
    - Check for simultaneous closing of all blades and for proper seating in the closed position.
9. Check the gear boxes for moisture that could cause damage due to corrosion or ice formation, if possible.

10. Ensure all nuts and bolts are tight, including the piercing bolts on the operating shaft.
11. Inspect the flexible braids or slip-ring contacts used for grounding the operating handle and replace those showing signs of corrosion, wear, or having broken strands.
12. Power-operating mechanisms for switches are usually of the motor-driven type. Follow the switch manufacturer's instructions for maintaining each mechanism. Check the limit switch including external switches for:
    - Poor contacts
    - Burned out coils
    - Adequacy of supply voltage
    - Any other conditions that might prevent the proper functioning of the complete switch assembly.
13. Inspect the overall switch and working condition of operating mechanism:
    - Check that the bolts, nuts, washers, cotter pins, and terminal connectors are in place and in good condition.
    - Replace items showing excessive wear or corrosion.
    - Inspect all bus cable connections for signs of overheating or looseness.
14. Inspect and check all safety interlocks while testing for proper operation.
15. Check the switch to ensure equal pole closing and opening.
16. Operate the switch to ensure its smooth operation. Listen for grinding noises or other signs of wear or malfunction.
17. Record any conditions that require follow-up repair. Follow up repairs require the initiation of a corrective work order/request.

<u>Motor Control Visual Inspection / Battery Replacement</u>

1. Visually inspect the switch-control unit for the following:
    - Condition of the control cable
    - Condition of the control cabinet
    - Compartment heater condition
    - Condition of the indicating lights
2. Check the battery date and replace the battery if it has expired or will expire within the next three (3) years.
3. Record any conditions that require follow-up repair. Follow up repairs require the initiation of a corrective work order/request.

Operational Test

1. Perform the operational test in conjunction with the 6 year De-Energized Major Maintenance for **Pole-Mounted** GOD / GOAB. Ensure that the switch is bypassed or transfer the load before performing the test.
2. Record any conditions that require follow-up repair. Follow up repairs require the initiation of a corrective work order/request.

Disconnect Switches – Substation NUMM 6.15B

Visual Inspection – Energized

1. Visually inspect the three phase disconnect switch for the following:
    - Insulators – damage
    - Frayed or broken flexible connections
    - Taps – from switch to line conductors and/or bus connections
    - Overheating (visual)
    - Condition of operating mechanism
    - Alignment of blades and proper contact
    - Signs of abnormal discharge, alignment and tripping linkage on load breaking devices
    - Mechanical condition of frame
    - condition or pitting of arcing horns, if applicable
    - Grounds and ground attachments
    - Obstructions that might obstruct operation or create a contact hazard
    - Debris – bird nests, kite string, etc. on switch
    - Squirrel Guards – missing or damaged, if applicable.
    - Confirm all switch numbers and phase markings are installed.
2. Record any abnormal conditions, any repairs made and any repairs still needed into Cascade.

Major Inspection – Energized

Note: This inspection is performed with the switch energized, but not under load.

1. Check the structural grounds for mechanical security.
2. Inspect the flexible braids or slipping contacts used for grounding the operating handle. Replace any braids showing signs of corrosion, wear, or having broken strands.
3. Examine the structure, mechanism enclosure and linkage for general condition.
4. Ensure mechanical locking devices are secure and in good operating condition.

5. Check both the open and close mechanical indicators.
6. Ensure that all Motor Operated Drive (MOD) control switches are in their normal position or are properly tagged.
7. Check MOD red and green indicating lights, if applicable.
8. Verify that rotating blades are fully seated and rotated, if applicable.
9. Visually check the alignment of the blade and jaw on each pole and verify the blades are latched, if applicable.
10. Check the insulator for chipped or cracked porcelain, and the accumulation of dirt or other contamination deposits (bird nest, strings, etc).
11. Check the condition of arcing horns and/or whips for pitting, burning and missing parts, if applicable.
12. Verify the operation of heaters and proper operation of the thermostats.
13. Note the position of the safety relief valve and check the indicator on switches using a vacuum or gas interrupting unit.
14. Visually check all electrical and mechanical connections for tightness and unusual wear.
15. Check for proper pressure and air leaks on switches employing Air Blast attachment.
16. Check for the condition and presence of all signage and phase designations.
17. Record any abnormal conditions, any repairs made and any repairs still needed into Cascade.

Major Maintenance – <u>De-Energized</u>

NOTE: Prior to beginning maintenance, a clearance must be obtained and the respective equipment must be de-energized and grounded in accordance with the applicable company procedure(s).

1. Isolate and ground the work zone.
2. Disconnect the switch from all electric power sources before servicing.
3. Check for broken plastic cams on the blades.
4. Inspect the insulators for breaks, cracks, burns, or cement deterioration.
    - Clean the insulators particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist. This is important as it will minimize the possibility of flashover resulting from the accumulation of foreign substances on the insulator surfaces.
    - Replace any broken or defective insulators immediately.

NOTE: The S&C disconnect switches require inspection/adjustment to ensure proper blade alignment.

5. Check the switch for alignment, contact pressure, eroded contacts, corrosion, and mechanical malfunction.

   NOTE: S&C Omni-Rupter Switch blade contacts are greaseless and self-lubricating. ***DO NOT*** apply lubricant to the blade contacts.

   - Replace damaged or badly eroded components.
   - If contact pitting is of a minor nature, smooth the surface with clean, fine emery cloth or as the manufacturer recommends. **Note:** Scotch Brite works well on silver contacts when a wire brush cannot be used.
   - Lubricate the contacts with a thin film of manufacturer – recommended, non-oxide grease *for non-self lubricating contacts only.*
6. Operate the switch several times and check it for smooth operation.
7. Lubricate the bearings, if applicable.
8. Check the blade latch for adjustment. Ensure the blades move freely and still are rigid enough for proper alignment with contacts.
9. Perform resistance testing on the contacts for each phase using a micro-ohm meter connected bus-to-bus. Record the results. Perform resistance testing on the remaining components including the jaws, hinges, and connectors, to determine their condition.
10. Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona.
11. Inspect inter-phase linkages, operating rods, levers, bearings, etc., to ensure that adjustments are correct, all joints are tight, and that pipes are not bent.
    - Clean and lubricate the switch parts, as required.
    - Check for simultaneous closing of all blades and for proper seating in the closed position.
12. Check the gear boxes for moisture that could cause damage due to corrosion or ice formation, if possible.
13. Ensure all nuts and bolts are tight, including the piercing bolts on the operating shaft.
14. Inspect the flexible braids or slip-ring contacts used for grounding the operating handle and replace those showing signs of corrosion, wear, or having broken strands.
15. Power-operating mechanisms for switches are usually of the motor-driven type. Follow the switch manufacturer's instructions for maintaining each mechanism. Check the limit switch including external switches for:
    - Poor contacts
    - Burned out coils
    - Adequacy of supply voltage
    - Any other conditions that might prevent the proper functioning of the complete switch assembly.

16. Inspect the overall switch and working condition of operating mechanism:
    - Check that the bolts, nuts, washers, cotter pins, and terminal connectors are in place and in good condition.
    - Replace items showing excessive wear or corrosion.
    - Inspect all bus cable connections for signs of overheating or looseness.
17. Inspect and check all safety interlocks while testing for proper operation.
18. Check the switch to ensure equal pole closing and opening.
19. Ensure that each switch-pole toggle mechanism lies against its closed stop, as applicable. Adjust the stop-bolt or crank-arm length as necessary. See the example shown in the figure below and refer to the appropriate manufacturer's manual.
20. Operate the MOD to ensure its smooth operation. Listen for grinding noises or other signs of wear or malfunction.
21. Record any abnormal conditions, any repairs made and any repairs still needed into Cascade.

Motor Control Visual Inspection/Battery Replacement

1. Visually inspect the switch-control unit for the following:
    - Condition of the control cable
    - Condition of the control cabinet
    - Compartment heater condition
    - condition of the indicating lights
2. Check the battery date and replace the battery if it has expired or will expire before the next scheduled maintenance, if applicable.
3. Record any abnormal conditions, any repairs mad and any repairs still needed into Cascade.

Operational Test

1. Perform the operational test in conjunction with maintenance of the equipment to which the switch is attached. Ensure that the switch is by passed or transfer the load before performing the test.
2. Record any abnormal conditions, repairs, or repairs made in the comments section.

Alignment Procedure – S&C

1. Open and close the interrupter switch vigorously through its full travel without hesitation at any point. Be prepared to apply additional force to maintain full speed when operating effort increases as the switch blades engage the interrupters.

CAUTION: Failure to properly adjust the handle may cause contact overheating or arcing, damaging the blade contacts. Injury to operating personnel may result.

2. Adjust the stop plates to remove all excess play from the operating mechanism and to attain proper “windup” tension before energizing the switch. Slack in the operating pipe may allow the switch to creep out of the fully-closed position.
3. Loosen the bolts that secure the adjustable stop plates to the foot bearing support plate.
4. Place the switch in the fully-open position and adjust the open-position stop plate so that the handle, when lowered, fits into the open-position slot.
5. Mark the location of the open-position stop plate on the support plate.
6. Fully close the switch and apply sufficient pressure to the handle in the closing direction to remove all play in the operating-pipe linkage.
7. Adjust the closed-position stop plate so that the handle will require even greater pressure to force it into the closed position slot.
8. Mark the location of the closed-position stop plate on the support plate.
9. While holding both stop plates in the previously marked positions, torque the bolts to secure the stop plates to the support plate.
10. Move the handle to the switch-open position and verify the handle, when lowered, fits firmly into the open-position slot.
11. Move the handle to the switch-closed position.
12. Verify that all play in the operating pipe linkage has been taken up before the handle can be lowered into the closed-position slot and that substantial pressure is required to force the handle into the closed-position slot.
13. Recheck to ensure that all clamp bolts and piercing set screws are properly tightened.

APPENDIX 8

POLE TOP REGULATORS

Regulators – **NUMM 5.01**

General Description

Regulators play a significant role in helping electrical loads operate most effectively at their rated voltage. It is important that the rated voltages supplied to these loads are maintained as nearly constant as possible.

NOTE 1: Major Maintenance for Substation regulators are only required when the results of oil analysis indicate there is a problem with the regulator and is typically performed at the shop. Major Maintenance for *all* Pole-top regulators is performed at the shop whenever they are taken out of service.

NOTE 2: The time interval between maintenance activities will depend upon frequency of tap-changer operation and the load on the regulator. Regulators subjected to numerous overloads and a high load factor may require more frequent inspections than those carrying normal loads. The initial maintenance interval will be as listed and will be adjusted in the future, based on collected performance data.

Failure finding

Failures of Voltage Regulators shall be documented in the equipment failure reporting system used by your region and placed in "To Eng" status for review.

Analysis of a failed Regulator may be performed as deemed necessary.

Routine Inspection – Energized – NUMM 6.01

Substation and Pole-Top

1. Perform touch potential testing on any metal surface that may be accessible to the public.
2. Check the regulator for any oil leaks or foreign material in the area.
3. Visually check to ensure grounding is properly installed and in good condition.
4. Check the condition of the control cabinet for moisture or other problems.
5. Measure regulated voltage at the test terminals to verify correct bandwidth.
6. Check for proper operation of the raise and lower controls.
    - If the regulator will not operate properly, try using a substitute control before removing the unit from service.
    - Refer to the manufacturer's instruction manual for the proper procedures on removing and replacing the control.
7. Verify the tap operations counter is working.

8. Verify and record the tap operations counter and tap indicator readings into cascade.
9. Ensure that all switches are in their normal positions.
10. Check to ensure animal guards are present, correctly installed, and in good condition.
11. Properly secure and lock the control cabinet.
12. Use binoculars to view the oil level window, if possible.
13. Inspect the bypass arrester, if present.

Oil Sample – Substation Only

Perform this step once every 5 years for Substation regulators.

NOTE: Only take an oil sample from those regulators that are equipped with an oil level sight gauge and a drain valve.

1. Check the oil level sight gauge and add oil as necessary so that an oil sample can be taken without leaving the regulator oil level too low. When performing this step, be sure to maintain safe working clearances from conductors and other electrical equipment or de-energize and ground the regulator.
    - If it is necessary to add oil before taking a sample, use the pressure relief valve to vent the regulator of positive or negative pressure.
2. Take an oil sample to submit for testing in accordance with TD 202 to ensure compliance with ChemLab requirements.
    - Use the pressure relief valve to vent the regulator of positive or negative pressure before taking the oil sample.
    - If the dielectric strength is found to be below 24kv, de-energize the regulator, filter or replace the oil, and perform dissolved gas analysis testing to determine the oil's integrity.

Major Maintenance De - Energized

NOTE: Prior to beginning maintenance, a clearance must be obtained and the respective equipment must be de-energized and grounded in accordance with the applicable company procedure(s).

WARNING: (Regulator bypassed): High pressure or mechanical failure due to improper bypass operation can cause death, severe injury or damage. To prevent these consequences, **bypass the regulator only with the regulator on the neutral tap position.**

WARNING: Siemens **MJ-X** L controls manufactured prior to August 2005 may have a defect that allows the control to indicate a false position reading. For example, the

control may indicate that the switch is in a “manual” position when in reality it is still in “auto” mode. This concerns only the **MJ-X** └ control and *not* the **MJ-X** control.

To ensure the regulator is in neutral:

1. Place the volt meter leads into the appropriate receptacles and observe the voltage readings.
2. Observe the voltage readings as you operate the Raise or Lower switch. Operate the regulator until the Indicating gauge reads neutral, while ensuring the voltage reading is still at appropriate levels.
    - If the control has a Neutral Light, ensure it turns on when the gauge is on neutral. If the light does not turn on, check the bulb and replace it if necessary.

At this point, the indicator position should read neutral *and* the neutral indicator light should be on. If *both* of these conditions are not met, then use an approved regulator neutral tester as an additional means of neutral verification.

Until there are at least two indications of neutral, DO NOT ATTEMPT to bypass the unit. In such event, de-energize the regulator to remove it from service.

1. De – energize the regulator
2. Remove the voltage regulator from the pole or pad/platform to perform de-energized maintenance.

CAUTION: When untanking the regulator, be sure to use the proper lifting point, *NOT* the regulator cover.

NOTE:

- All Pole-Top regulators will receive their Major Maintenance at the shop.
- Substation regulators receive their Major Maintenance at the shop except for those units too large to move.
- Untanking the regulator is not to be performed in the field, except for those Substation regulators which are not practical to move due to their size.

3. Untank the regulator.

NOTE: Avoid removing the main core-and-coil assembly from the oil, except when a winding failure occurs. Use blocking between the cover and tank lip to suspend the core and coil assembly within the oil until inspection of the tap changer or other maintenance is complete. If it is necessary to expose the main core and coil to air, follow the manufacturer’s instructions before returning the unit to service.

4. Make a thorough inspection of all internal components – particularly noting contact wear, springs, and chain
    - Determine the remaining contact life by noting the amount of contact erosion which has occurred as compared to the amount of arcing material remaining.
    - When inspecting contact wear, inspect both stationary and movable contacts.
    - Refer to manufacturer's instruction manual for contact wear guidance.
    - Be especially watchful for inadequate contact pressure, unequal pressure on both sides of contacts, contact alignment and carbon formation on any portion of all contact structures.
5. Check for signs of oil leaking from any seal or gasket.
6. Check all chain and gear parts carefully for chipped or broken teeth or excess backlash in its operation.
7. Check all connections for tightness and over heating.
8. Operate the mechanism through its entire range to ensure there is no mechanical interference and that contact alignment is proper on all steps.
9. Adjust the tap changer to ensure it goes through the neutral position.
10. Operate the regulation equipment to the fully raised and the fully lowered positions to check the upper and lower limit switch operation.
11. Ensure the drive mechanism stops properly on position.
12. Check the counter for proper operation.
13. Use cleaning insulating oil with the proper dielectric strength to refill the regulator.
14. Perform a power factor test (Doble) to determine the insulation integrity of the regulator.
15. Perform an insulation resistance test (megohmmeter).
16. Perform a Transformer Turns Ration Test.
17. Check internal and external motor capacitors.
18. Return the regulator to CMS/DERF Shop for a more thorough repair or disposal if it cannot be made to function within specification.

When the inspection is complete, the unit is ready for service.

Return to Service

The return to service procedure is essentially the reverse of the procedure used to remove the regulator from service. Energize the regulator ***only*** with regulator on neutral tap position.

Siemens MJ-X └ Controls

Use the following procedure when placing and MJ-X └ equipped regulator into or out of service. Note that these steps are only for placing the regulator into or out of service. You must still perform the inspection steps, such as the power factor test, TTR, insulation test, etc. that are in the previous section.

Placing the regulator into service:

1. Place the Auto/Manual switch in the Bypass position.
2. Place the Raise/Lower switch in “off”.
3. Make certain the regulator is in the Neutral (N) position.
4. Turn the voltage Power Source switch to “off”.
5. Remove the control power fuse.
6. Close, sequentially, the source and the load switches.
7. Open the bypass switch.
8. Visually observe that the bypass circuit has opened.
9. Replace the control power fuse.
10. Place the voltage power source switch to “Normal”.

Removing the regulator from service:

1. Place the Auto/Manual switch in the Bypass position.
2. Place the Raise/Lower switch in “Off”.
3. Make certain the regulator is in the Neutral (N) position. If independent checks of the position indicator and the neutral light indicator do not confirm the neutral position, bypassing must not be attempted. In such an event, de-energize the system to remove the regulator from service.
4. Turn the voltage power source switch to “off”.
5. Remove the control power fuse.
6. After ensuring the regulator is in Neutral (N), close the bypass switch.
7. Open sequentially, the load and source switches.
8. Perform the applicable action:
    - For single phase or grounded wye connection, make sure the high voltage disconnect switches are opened.
    - For closed delta connection, ensure all regulators in the bank are bypassed and isolated.
9. Exercise appropriate care in the removal of the regulator. High voltage will still be present at the bypass switch and the source and load switch terminals. Remove the ground connection last.

APPENDIX 9

RECLOSERS AND SECTIONALIZERS

Automatic Circuit Reclosers (ACR) & Sectionalizers

General Description – NUMM 5.44

Reclosers sense and interrupt fault currents and automatically restore service after momentary outages. The automatic circuit recloser is essentially a self-contained device with the necessary intelligence to sense over currents, to time and interrupt fault currents, and to re-energize the line by reclosing automatically. If a fault is permanent, the recloser locks open after a preset number of operations, isolating the faulted section from the main part of the system. Automatic circuit reclosers installed at Northeast Utilities:

- Can be either Single-phase or Three-phase
- Can have either Oil or Vacuum Interrupters
- Can have either Hydraulic or Electronic Controls
- Can be either Oil or Epoxy Insulated

Single-phase reclosers are used to protect single-phase lines such as branches or taps of a three-phase feeder. They can also be used on three-phase circuits where the load is predominantly single phase.

Single phase reclosers installed at Northeast Utilities include (not a complete list) Type H, 4H, V4H, L, V4L, VXE15, D, E, 4E, V4E, and DV. (See Appendix 2.)

Three phase reclosers are used as main feeder breakers on three phase feeders. The three phase reclosers are also used as part of the DSCADA System, which is used to segment the feeder into multiple zones of protection. When a fault is detected, the reclosers are programmed to isolate the fault and automatically restore service to as many of the affected segments as possible.

Three phase reclosers installed at Northeast Utilities include (not a complete list) Type 6H, V6H, W, WE, VWE, WVE27, VWVE27, NOVA27, WVE38X, VWVE38X, VSO12, and NOVA38. (See Appendix 2.)

Recloser Controls provide the intelligence that enables a recloser to sense over-currents, select timing operation, time the tripping and reclosing functions, and finally lockout the circuit when required. There are two basic types of controls used: an integral hydraulic control or an electronic control located in a separate cabinet.

- **Hydraulic recloser controls** are used in most single-phase reclosers and in three-phase recloser types 6H, V6H, and W. The controls are an integral part of the recloser. With this type of control, an over-current is sensed by a trip coil that is connected in series with the line.

- **Electronic recloser controls** are used in most three-phase reclosers and in the single-phase Cooper recloser types VXE and NOVA.

Note 1: SCADA Pole Top reclosers are monitored continuously and do not require the monthly checks. They will be inspected for physical damage on an annual basis.

Note 2: Duty cycle is calculated based on the number and magnitude of fault interruptions. The duty cycle is calculated and monitored by all electronic controllers (except Form 3A). If a duty cycle monitor is not available, use a count of the operations (Hydraulic controls and Form 3A).

Pole Top Reclosers – SCADA

Check and Inspection – <u>Energized</u> - Yearly

1. Make a visual inspection of the recloser:
   - Check the ground integrity.
   - Check to ensure proper installation of lightning arresters.
   - Check for oil leaks, if applicable.
   - Check the condition of the Bushing.
   - Check to ensure animal guards are present, correctly installed and in good condition.
2. Record the counter reading.
3. Inspect the control cables and connectors for damage and for water intrusion into the.
4. Check the oldest battery date (in case of multiple dates) and replace the battery based on its age as follows:
   - Form 3A controls - replace every 5 years
   - Form 4C controls - replace every 3 years
   - Siemens controls - replace every 3 years
   - Form 6 controls - replace every 4 years
   - Schweitzer SEL-651R Controls – replace every 3 years.
5. Check the battery terminal voltage.
6. Test the battery terminal voltage.
7. Check the heaters and the AC supply to battery charger.

Pole – Top Reclosers – Non-SCADA

ELECTRONIC

Check – Energized – Every Two Months

1. Record the operations counter reading. If the number of operations exceeds the duty cycle limit, schedule a Major Maintenance.
2. Check all metering and indicating devices and inspect all control switches for normal position or electronic indication.
3. Inspect the control cables and connectors for damage and for water intrusion into the connectors.
4. Make a visual inspection of the recloser:
   - Check the ground integrity.
   - Check to ensure proper installation of lightning arresters.
   - Check for oil leaks, if applicable.
   - Check the condition of the Bushing.
   - Check to ensure animal guards are present, correctly installed and in good condition.
5. check the battery date and replace the battery based on its ages as follows:
   - Form 3A controls – replace every 5 years
   - Form 4C controls – replace every 3 years
   - Siemens controls – replace every 3 years
   - Form 6 controls – replace every 4 years
   - Schweitzer SEL-651R controls – replace every 3 years.
6. Check the battery terminal voltage.
7. Test the battery with a dummy load.
8. Check the heaters and the AC supply to batter charger.

HYDRAULIC

Check – Energized – Annually

1. Make a visual inspection of the recloser.
2. Record the Operations Counter reading.
3. Check all metering and indicating devices and verify all control switches for normal position or electronic indication.

Recloser – All – Major Maintenance – De-Energized

While most Major Maintenance for reclosers is performed at a maintenance shop, some is performed on-site. Perform the following steps:

1. Remove the unit from service.
2. Measure contact resistance to provide and indication of contact condition as well as loose current carrying parts. Use of the doctor is the recommended method.
3. Perform an insulation test (utilizing a Megger), phase-to-phase, and phase-to-ground.
4. Inspect and dress the main and control contacts, if necessary.
5. Perform both mechanical and electrical inspections on the interrupting chambers.
6. Check clearance and adjust them to manufacturer's specifications for the recloser model.
7. Check all electrical and mechanical connections for correct tightness.
8. Thoroughly clean all internal mechanisms and tanks, and remove all carbon. Check for traces of tracking on all insulating parts and moisture absorption of the bottom of the tank liner.
9. Check and adjust the component parts of the operating mechanism, if required.
10. Check all gaskets.
11. Make a complete trip test with an electronic control unit connected to recloser, if applicable. If closing coil supply voltage is not available, test the control only.
12. For hydraulically controlled reclosers, operate the recloser manually to lockout, verifying minimum pickup and time current characteristics.
13. Thoroughly clean the exterior of the recloser.
14. Inspect the exterior of the recloser for:
    - Cracked or broken bushings. Replace as necessary.
    - Paint scratches or other mechanical damage. Repaint as necessary to prevent corrosion.
15. Refer to the Manufacturer's manual for maintenance requirements specific to the recloser model you are servicing.
16. Perform a dielectric test of the oil
17. Change lightning arresters, as requires.

Vacuum Under Oil Device (Perform these steps in *addition* to the Major Maintenance).

1. Perform an AC high potential test on each interrupter in accordance with manufacturer's instructions or NU specifications. Perform this test carefully as it provides the best means for verifying the condition of the interrupter.
2. If the manufacturer has provided a scribe mark for monitoring contact erosion, check the reference dimension to measure wear.
3. Perform Doble testing on all reclosers over 19.9 kv.

Solid Dielectric Vacuum Recloser (Siemens and cooper NOVA Reclosers and G&W Viper)

No user maintenance of the recloser mechanism is required. The recloser should be considered for refurbishment or retired if the mechanical duty or breaking duty on any phase is exceeded. You can determine this by examining the remaining life on the Operator Control Panel. Further details on maintenance on the recloser and control cubicle are located in the Siemens or cooper instruction book.

Sectionalizers (SEC3) and Voltage Switches (VS)

General Description

The importance of following a strict maintenance program on sectionalizers cannot be over-emphasized. The nature of these devices is such that they operate primarily during times of emergency. It is their function to limit service interruptions on permanent faults to a relatively small group of customers. Failure to operate properly increases the cost and time required to restore service following an emergency and reduces the system reliability.

Sectionalizers are used with reclosers and reclosing circuit breakers to isolate permanent faults and confine outages to smaller sections of line on electric power distribution systems. They are applied on the load side of the fault-interrupting device, and can be set to trip and lockout during the first, second, or third open interval of the recloser or breaker. They are not rated to interrupt fault current; however, they can safely be closed into a fault, and can interrupt load current.

Voltage Switches (VS) are those reclosers that are used as sectionalizers. Their trip settings are so high they will never trip for fault current before upstream protective devices operate. Because of the "lighter duty" service they perform, they are maintained to the same schedule as regular sectionalizers. <u>When a recloser is used as a VS, it shall be maintained as a recloser.</u>

Pole-Top Sectionalizers and Voltage Switches (VS)

Sectionalizer and VS – Check – <u>Energized</u>

1. Perform a visual inspection and record the operations counter.

Sectionalizer and Voltage Switch IR Survey Inspection

1. Perform an Infrared test during a Distribution IR Survey or as require.

Sectionalizer and VS Major Maintenance – <u>De-Energized</u>

Note: Sectionalizers that have problems will be replaced and taken back to the shop for inspection/maintenance.

1. Perform a doctor test to measure contact resistance to provide an indication of contact condition as well as loose carrying parts.
2. Perform an insulation resistance test (utilizing a Megger), phase-to-phase, and phase-to-ground.
3. Test for proper operation on the Sectionalizer.
4. Inspect and dress the main and control contacts, if necessary.
5. Inspect interrupting chambers for both mechanical and electrical conditions.
6. Check all electrical and mechanical connections for tightness.
7. Thoroughly clean and remove carbon from the internal mechanism and tanks.
8. Check for traces of tracking on all insulating parts and moisture absorption of the bottom of the tank liner.
9. Check and adjust the component parts of the operating mechanism, if required.
10. Check all gaskets.
11. Ensure the tap wires are properly tightened.
12. Paint, where necessary.
13. Test Oil (Color and dielectric strength); filter and/or replace as necessary.

<u>Failure Finding</u>

Failures of reclosers and sectionalizers shall be documented in the equipment failure reporting system used by your region.

SUBSTATION (S/S) Reclosers – SCADA Monitored/Controlled - **NUMM 6.44**

Check and Inspection – <u>Energized</u> – Monthly

1. Make a visual inspection of the recloser:
   - Check the ground integrity.
   - Check for oil leaks, if applicable.
   - Check the condition of the bushings to ensure they are not blown or badly chipped, when practical.
   - Check to ensure animal guards are present, correctly installed and in good condition.
   - Check the control cable for damage from animals, vandalism, etc.
2. Record the operations counter reading.
3. Inspect the control cables and connectors for damage and for water intrusion into the connectors to the extent possible.

   CAUTION: Some recloser controls must be removed from service before you can replace their batteries.

4. Check the date on the batter sticker and replace the batteries (as a set) based on their age as follows:
   - Form 3a controls – replace every 5 years
   - Form 4C controls – replace every 3 years.
   - Siemens controls – replace every 3 years
   - Form 6 controls – replace every 4 years
   - Schweitzer SEL-651R controls – replace every 3 years.
5. Check the battery terminal voltage.
6. Test the battery with a dummy load. This can be done with an internal test program, if the recloser is so equipped, or by using an external load device.
   - A 3 – 4 volt drop is normal. A larger drop in voltage indicates the batteries are worn and due for replacement.
7. For VIPER Reclosers, check the Enable Supply Light:
   - GREEN – OK
   - OFF – Notify Supervisor
8. For VIPER Reclosers, check the Battery Problem Light:
   - OFF – OK
   - RED – Notify Supervisor
9. Check the heaters and the AC supply to the battery charger.

S/S Reclosers – Non-SCADA

ELECTRONIC

Check and Inspection – Energized

1. Record the operations counter reading.
2. Check all metering and indicating devices and inspect all control switches for normal position or electronic indication.
3. Inspect the control cables and connectors for damage and for water intrusion into the connectors to the extent possible.
4. Make a visual inspection of the recloser:
    - Check the ground integrity.
    - Check for oil leaks, if applicable.
    - Check the condition of the bushings to ensure they are not blown or badly chipped, when practical.
    - Check the control cable for damage from animals, vandalism, etc.
    - Check to ensure animal guards are present, correctly installed and in good condition.

    CAUTION: Some recloser controls must be removed from service before you can replace its batteries.

5. Check the date on the battery sticker and replace the batteries (as a set) based on their age as follows:
    - Form 3A controls – replace every 5 years.
    - Form 4C controls – replace every 3 years.
    - Siemens controls – replace every 3 years.
    - Form 6 controls – replace every 4 years.
    - Schweitzer SEL-651R controls – replace every 3 years.
6. Check the battery terminal voltage.
7. For VIPER Reclosers, check the Enable Supply Light:
    - GREEN – OK
    - OFF – Notify Supervisor
8. For VIPER Reclosers, check the Battery Problem Light:
    - OFF – OK
    - RED – Notify Supervisor
9. Test the battery with a dummy load. This can be done with an internal test program, if the recloser is so equipped, or by using an external load device.
    - A 3 – 4 volt drop is normal. A larger drop in voltage indicates the batteries are worn and due for replacement
10. Check the heaters and the AC supply to the batter charger.

S/S Reclosers – Non-SCADA

HYDRAULIC

Check – Energized

1. Make a visual inspection of the recloser.
2. Record the operations counter reading.
3. Check for the following:
    - Ensure there are no oil leaks.
    - Check to ensure animal guards are present, correctly installed and in good condition.
    - Ensure that lightning arresters are present and in good condition.
    - Ensure the Trip/Close lever is in its normal position.

APPENDIX 10

INSPECTION, TREATMENT, RESTORATION AND REPLACEMENT GUIDELINES FOR DISTRIBUTION SYSTEM WOOD POLES

Wood Poles – **NUMM 5.61**

General Description

This procedure establishes a uniform approach for distribution wood pole inspection, treatment, restoration and replacement. It defines the schedule, inspection, and reporting requirements for these facilities.

This applies to all wood distribution poles within the custodianship or the maintenance responsibility of Northeast Utilities. It shall include push braces and guying stub poles as well as line poles scheduled for the given year.

Facilities/Equipment

- Wood Poles

Routine Inspection – NUMM 6.61

Visual

A visual (only) inspection is to be performed on:

- CCA Treated Poles ----------0 – 19 years old
- Creosote, Penta, and all other poles----------0 – 9 years old

This shall be the first step for inspecting each pole, and shall include a thorough observation of the above-ground portion of each pole and all attachments. Record any findings into the system appropriate for the activities being performed.

1. Visually inspect the pole for the following defects:
    - Pole top split or deteriorated
    - Crossarm damaged or decayed
    - Broken or damaged insulator
    - Broken or damaged spacer
    - Buried anchor guy
    - Broken guy wire
    - Leaning pole

2. Check to see if the pole is set shallow.
   The following table indicates the correct distance from the ground-line to the bottom of the pole brand:

Length of Pole (in feet)	Groundline Distance	
	To Butt	To Brand
25	5	5
30	5.5	4.5
35	6	4
40	6	4
45	6.5	3.5
50	7	3
55	7.5	6.5

- Measure the distance from the ground line to the bottom of the pole brand. If the distance is *more than 6 inches greater* than the value in the 3rd column of the above table:
  a. Attach an aluminum pole tag letter "**S**" just below the bottom of the pole brand.
  b. Record the information into Cascade or into the appropriate inspection record.
- *Do not* record this pole as set shallow if there is an "**R**" tag attached to the pole just below its brand, as this indicates the presence of enough rock to support the pole.

Sound & Bore Inspection Pole in Ground

A Sound & Bore Inspection is performed on:

- CCA treated poles----------20 years old and older
- Creosote, Penta, and all other poles----10 – 14 years old.

1. Sound the pole all around, listening for hollow sounds that may indicate decay or insect damage.
   - Strike the pole firmly (not hard) with a hammer from the ground line upward to as high as you can reach, approximately 8 feet above the ground line.
2. Pull back the soil at ground line on two sides of the pole, giving pullback priority to any suspicious sounding areas or visually suspect areas.
   - Each pullback should be approximately shovel's depth and 6" wide.

3. Bore a 3/8” hole into the pole at a 45 degree angle from the ground line to the center of the pole, and wherever there were any suspicious areas detected by sounding, in order to detect insect damage or damage due to decay.
    - If no insect damage or decay is detected, do not treat the pole.
4. Evacuate any voids found within the pole.
    - If the pole passes inspection, fill the void and coat the outside with the appropriate treatments.
5. Plug all bored holes with 7/16” treated dowels (2” to 3” long), and tamp the pulled-back soil neatly into place.

Sound & Bore Inspection – Poles In Pavement

This includes those poles that are surrounded by pavement, or that have riser pipes or other obstructions that prevent excavation.

A Sound & Bore inspection is performed on:

- CCA treated poles ----------20 years old and older
- Creosote, Penta, and all other poles--------10 - 14 years old

1. Bore each pole with the 3/8 inch x 18 inch or 24 inch inspection bit at a 45 degree angle from above ground ine to below ground line to look for decay or insect damage.
2. Evaluate decay as specified in the Circumference Measurement section on page 5.
3. Treat the pole. If the pole exhibits some decay, but still passes inspection, internally treat the pole with:
    - “WOODFUME” if there are no internal voids
    - “Hollow Heart” if there are internal voids.

Ground Line Inspection

A ground line inspection is performed on:

- Creosote, Penta and all other poles---------15 years old and older

NOTE: *Do not* excavate a pole set shallow until Division Operations advises that the situation has been corrected.

1. Excavate each pole all around to a depth of 18 inches, leaving at least 4 inches of radial clearance at the bottom of the excavation.

2. Use a wire brush to clean the below-ground portion of the pole and use a check scraper to locate any exterior decay.
3. Sound the pole all around.
4. Bore a 3/8” hole into each pole at a 45 degree angle from the ground line to the center of the pole and wherever decay or insect damage is suspected.
5. Plug all bored holes with a 7/16” preservative treated wood dowel (2” – 3” long).
6. Use a shell thickness indicator to measure voids and the thickness of the outer shell.
7. Remove by chipping, all loose weathered wood and wood overhanging deteriorated wood to at least 6 inches above ground line. See the following section on Circumference Measurements.
8. Remove all exterior wood from the pole surface to be treated using care not to remove any sound wood unless that is essential to inspection/treatment.
9. Remove all chipped wood debris from the hole and properly dispose of it away from the site.

Circumference Measurement

Evaluate a pole if its effective ground line circumference has been reduced by decay or insect pockets, hollow heart, mechanical damage or has had exterior decayed wood removed by chipping prior to ground line treatment.

Calculate the percentage of the remaining pole strength based on the effective ground line circumference and the existing conductor and attachment load.

Remove from service, any corner (angle) poles, dead end poles, guy stubs and push braces with less than 80% of their original ground line circumference. Circumference measurements for new poles are listed below in the following table.

Length of Pole or Feet From Top	Minimum Dimension (in Inches)	Class						
		H-2	H-1	1	2	3	4	5
0’	Diameter	9.9	9.2	8.6	8.0	7.3	6.7	6.0
	Circumference	31.0	29.0	27.0	25.0	23.0	21.0	19.0
2’	Diameter	10.2	9.5	8.8	8.2	7.5	6.9	6.3
	Circumference	31.9	29.8	27.8	25.8	23.7	21.7	19.7
5’	Diameter	10.6	9.9	9.3	8.6	7.9	7.3	6.6
	Circumference	33.2	31.1	29.1	27.0	24.9	22.8	19.7
10’	Diameter	11.3	10.6	9.6	8.9	8.3	7.7	7.0
	Circumference	35.4	33.2	30.0	28.0	26.0	24.0	22.0
15’	Diameter	12.0	11.2	9.9	9.2	8.6	8.0	7.3
	Circumference	37.6	35.3	31.0	29.0	27.0	25.0	23.0
20’	Diameter	12.7	11.9	10.7	10.0	9.4	8.8	8.1
	Circumference	39.8	37.4	33.5	31.5	29.5	27.5	25.5
25’	Diameter	13.4	12.6	11.6	10.9	10.2	9.5	8.7
	Circumference	42.0	39.5	36.5	34.0	32.0	29.5	27.5
30’	Diameter	13.8	13.2	12.4	11.6	10.9	10.0	9.2
	Circumference	43.5	41.5	39.0	36.5	34.0	31.5	29.0
35’	Diameter	14.6	13.8	13.1	12.3	11.5	10.7	9.9
	Circumference	46.0	43.5	43.5	38.5	36.0	33.5	31.0
40’	Diameter	15.4	14.5	13.7	12.8	11.9	11.1	10.3
	Circumference	48.5	45.5	43.0	40.5	37.5	35.0	32.5
45’	Diameter	16.1	15.1	14.3	13.3	12.0	11.7	
	Circumference	50.5	47.5	45.0	42.0	39.0	36.5	
50’	Diameter	16.6	15.8	14.7	13.8	12.9		
	Circumference	52.0	49.5	46.5	43.5	40.5		

Ground line (diameter or circumference) dimensions for an pole are measured at 5 feet from the bottom of the pole.

Reject Poles

Priority Poles

Reject all priority poles. A priority pole is one which is in imminent danger of falling because it is completely decayed across the grain, or it has a hollow heart with sound wood in the outer shell of one inch thickness or less.

- Use the C-aluminum pole tag which measures 2 inches high and 2-1/2 inches wide. It has a clear aluminum arrow with an "X" inscribed in a circle imposed on the shaft of the arrow on a red background.
- Paint a yellow "X", approximately 1 foot square in size, on the roadside of the pole, centered approximately 6 feet above the ground line. Then, attach one C tag centered on the "X" and attach another C tag at approximately the same height on the field side of the pole.
- If the pole is defective in the ground line section, place the tags so the arrow points downward. If the pole is defective in the upper portion, place the tags so the arrow points upward. If, however, the pole is defective in both the ground line section and in the upper portion place a double set of tags, one set with the arrow pointing downward and the other set with the arrow pointing upward. Attach the tags with 1-1/4 inch galvanized roofing nails.
- **Report the pole immediately** by telephone, radio, or email (whichever is appropriate for your company requirements) to the appropriate district.
- Record the information in the computer database and include the name of the person the reject information was reported to in the comments section.

NOTE: Check the pole within 48 hours and make the pole safe within 5 working days of receiving notice.

Normal Reject Poles

Normal reject poles are those poles which have effective circumferences equal to or less than the minimum ground line circumference at replacement (normally 67% of original circumference) but which are not deteriorated enough to be classified as "priority poles". Circumference measurements for new poles will be provided in the Instructions chapter.

- Reject decayed poles having a minimum shell thickness of less than 2 inches.

○ If the hollow heart is the result of severe ant or termite infestation, then reject those poles having a minimum shell thickness of less than 3 inches.

- Normal reject poles shall be identified as follows:

  ○ Use the B-aluminum pole tag which measures 2 inches high and 2-1/2 inches wide. It has a clear aluminum arrow on a red background.

  ○ Attachment instructions for the B tag are the same as for the C tag used to identify priority poles in the preceding section.

- Record the information in Cascade.

Refer to Instruction 6.61A for details on evaluating "Normal" reject poles and performing their restoration

Wood Pole Restoration – **NUMM 6.61A**

This section of the NU Maintenance Manual provides instruction for determining which Reject Poles (as defined in section 6.61 of the manual) are suitable for repair or restoration as a means to extend their useful life by at least:

- 15 years* (the inspection interval for wood poles not planned for replacement) or
- 5 years (for poles scheduled for replacement within that period)

It also provides guidelines for determining which poles may not be restored.

Guidelines for Reject Pole Restoration

All of the following requirements must be met in order to qualify a pole for restoration:

1. No circuit rebuild requiring taller or larger class poles is planned within the present planning period. Search the Work Management System by pole number to determine if other work has been planned for that pole and proceed accordingly.
2. No equipment additions (capacitors, reclosers, regulators, switches or transformers) that would require a taller or larger class pole are expected in the near future.
3. Telephone Company concurs with pole restoration for those poles jointly owned. (Refer to guidelines for jointly owned poles below).

4. If applicable, State Highway Department concurs with pole restoration for poles along state highways. For the State of Connecticut, written approval must first be obtained from the appointing authority of the local municipality of the state route where pole restoration is planned. A permit by the State of Connecticut Department of Transportation will not be issued unless approval from the municipality is included with the request.

Restoration Guidelines for poles jointly owned with AT&T (Connecticut only):

AT&T encourages pole restoration for the following cases:

- Pole with AT&T aerial or ground level interface boxes attached.
- Poles with large communication cable risers attached.
- Poles in Right of Ways.
- Poles 45 feet and above.

Guidelines for Reject Pole Replacement

Reject poles are categorized as either a Normal Reject or a Priority Reject pole, as follows:

- A **Priority Reject** pole is one which is in imminent danger of falling because it is completely decayed across the grain, or is a pole having a hollow heart with sound wood in the outer shell of one inch thickness or less.
- A **Normal Reject** pole is one that has an effective circumference equal to or less than the Minimum Ground line Circumference at Replacement (normally 67% of original circumference) but which is not deteriorated enough to be classified as a “Priority Reject” pole.

1. Replace all poles found to be Priority Reject poles.
2. Evaluate the condition of the entire pole. If there are cracks, splits, or rot at the top, extensive woodpecker holes, or other damage that would make it impractical to extend the life of the pole by restoring the pole at the ground line, then the pole should be replaced rather than restored.
    - **Exception to this rule:** If you know that the pole will be relocated or replaced for other reasons within the next five years, and restoration will extend its life at least for that period, then restore the pole instead of replacing it.

3. Assess the need to climb the pole in the future. If the pole cannot be easily reached with a bucket truck **and** the condition of the pole above the ground line is not sufficient to allow climbing, then replace the pole.
4. Determine if the pole is the correct class and height to support the facilities that are on it. The NU Distribution standards provide the required clearances and guidance to calculate the strength requirements to support the electric and communications equipment. If it is determined that the existing pole is not sufficient due to strength or clearance issues, then replace it with the correct class and height pole.
5. Return to Distribution Maintenance and Construction a list of those poles which you have confirmed can be restored. For those which you have determined cannot be restored, state the reason(s) in writing why they cannot be restored.
6. Replace poles on scenic highways or in historical areas of towns (Connecticut only).

Guidelines to replace defective poles jointly owned with AT&T (Connecticut only):

AT&T encourages replacing defective poles under the following conditions:

1. Replace 35' poles with power primary, secondary/neutral and communications cables that cross a road. Poles with 3 phase primary, secondary and communications equipment should be replaced with a tall pole to provide access to the field side of the pole if the 35' pole is found to be defective.
2. Replace 35' poles with power primary, secondary/neutral and more than 3 attachments in the communications gains.
3. Replace 40' poles with power primary, secondary/neutral and more than 5 attachments in the communications gain. Evaluate the pole height to ensure that proper clearance requirements are met.
4. Replace any pole that is inadequate for <u>planned</u> AT&T construction.
5. Replace any pole that does not meet AT&T or State of Connecticut DOT criteria for pole restoration.

NOTES:

- Attachments in the communication gain refer to all attachments, roadside and field side, including bare strand. (AT&T, Municipal, State, CATV, other communication companies)

- Questionable poles will be reviewed by AT&T Line Construction/AT&T Engineering upon request.
- It is requested that pole maps of the projected pole inspection be supplied to AT&T for review. AT&T will identify areas of planned construction and reply back to NU.

Pole Restoration

Poles evaluated as normal reject poles by the inspector shall be noted in the computer database as "Restorable" if there is sufficient shell thickness to transfer the strength of the steel reinforcing member to the wood pole. A normal reject pole is restorable with one of the following options if it meets the following minimum criteria.

C-Truss System

1. Sound the pole thoroughly above the ground line again. Concentrate at the zone 15 inches to 4-1/2 feet above the ground line.
2. Drill at 4-1/2 feet above the ground line against the line of lead.

    - If this boring indicates less than a 4 inch shell thickness a second boring is made opposite (180 degrees from) the first boring whenever possible. Other borings should be taken as necessary.
        - o If the average shell thickness is 4 inches or more at the 4-1/2 foot height, the pole can be restored using a C-Truss.
        - o If the average shell thickness is less than 4 inches at the 4-1/2 foot height, the pole should be bored at 5-1/2 feet. If the average shell thickness is 4 inches at this height, then the pole can be restored using a *larger* C-Truss.
        - o If the average shell thickness is less than 4 inches at both 4-1/2 and – 5-1/2 foot heights, then use a Fiberwrap System to restore the pole.

3. Drill at 15 inches above the ground line against the line of lead.

    - If this boring indicates less than a 2 inches shell thickness, a second boring is made opposite (180 degrees from) the first boring whenever possible. Other borings should be taken as necessary.

- If the average shell thickness at 15 inches is 2 inches, the pole can be restored using a C-Truss.
- If the average shell thickness at 15 inches is less than 2 inches, bore the pole at a 26 inch height. If there is a 2 inch average at the 26 inch height, the pole can be restored using the *larger* C-Truss.
- If the average shell thickness at both 15 inch and 26 inch heights is less than 2 inches, then use a Fiberwrap System to restore the pole.

Fiberwrap System

1. Drill at 6 feet above the ground line against the line of lead.

   - If this boring indicates less than a 4 inch shell thickness, a second boring is made opposite (180$_o$ from) the first boring whenever possible. Other borings should be taken as necessary.
     - If the average shell thickness is 4 inches or more, the pole can be restored using a Fiberwrap.
     - If the average shell thickness is less than 4 inches, continue boring at 6 inch intervals up the pole until a 4 inch average shell thickness is obtained or the height of 10 feet is reached.
     - If 4 inches of shell thickness if found at a height of 10 feet or less, the pole can be restored using a Fiberwrap.
     - If an average of a 4 inch shell does not exist from 6 to 10 feet, the pole cannot be restored.

APPENDIX 11

UNDERGROUND SWITCHES

Underground Switches

General Description – NUMM 5.51

Underground systems contain many types of switches. There are oil switches, oil-vacuum switches, fusible switches, SF6 vacuum switches, etc. The switches generally are constructed for submersible application and are located in manholes, vaults or on concrete pads in subway system areas. The purpose of these switches is to isolate sections of circuits in order to minimize the number of customers interrupted due to faults on the circuits or to transfer loads from one circuit to another.

Many of the older types of switches have been replaced over the years as 5 kV and below systems have been converted to systems ranging from 15 kV to 35 kV. There are projects to convert more of the 5 kV and below systems to the 15 kV to 35 kV range. Completion of these projects will result in the removal of more of the older types of switches. Switches installed in these conversion areas and in new underground areas are the standard SF6 vacuum switches. Industry-standard rubber molded products are used to connect the switches to Tree Retardant XLink or ethylene propylene rubber insulated primary cables.

Routine Inspection – Energized – NUMM 6.51

1. Ensure the switch data on the ID tag matches the information on the Cascade work order.
2. Visually check the switch for leaks. If a gauge is available, record the pressure/level.
3. For SF6 – insulated switchgear, check for leaks using the installed gauge.
4. Check the switch for any discoloration.
5. Check the switch for corrosion. Use paint to touch up any areas that are accessible.
6. Observe the exterior switch for general condition.
7. Observe the primary connections on the switch for any unusual conditions. See 6.49, “Underground Cables.”
8. Check that switch is physically secured in place, if it is not installed a flat horizontal surface.
9. Ensure the switch is grounded to the manhole, vault, or concrete pad ground grid.
10. Check for the presence of anodes and the condition of their connections. Refer to section 6.54 “Underground Corrosion.”
11. Ensure equipment nomenclature and status indicators are present and in good condition. Clean or replace as required.

12. Infrared check primary connections and accessible energized parts (e.g. bus work, blades, etc) if IR equipment and personnel are available.
13. Refer to manufacturers manuals for specific requirements for the switch being serviced.
14. Repair all conditions that can be fixed at the time of maintenance. Record all findings and results in Cascade.

Conditioned Based

Correct any conditions found during Routine Inspection or record the conditions and schedule them for future replacement.

Failure Finding

A failure report shall be completed for any underground switch failure and placed in the appropriate failure tracking system.

Analysis of underground switch failures should be performed when deemed necessary by Distribution Standards.

APPENDIX 12

UNDERGROUND SYSTEM - NETWORK TRANSFORMERS

Network Transformers

General Description – NUMM 5.30

A network transformer transforms a primary voltage down to the voltage of a secondary network grid. A network transformer is designed and constructed to operate in harsh environments such as street vaults, sidewalk vaults and customer building vaults.

A network transformer consists of two main sections. The first section is the main tank in which the core and coils are located and the second section is the high voltage switch. The *standard* network transformer has a one-compartment high voltage switch, but there are also network transformers with a two-compartment high voltage switch in service. One compartment of this high voltage switch contains the switch mechanism and the other compartment is the high voltage termination compartment.

The insulating fluid that is in the main tank of a standard network transformer is transformer oil and the insulating fluid that is in the high voltage switch of a standard network transformer is a less flammable insulating fluid. There are other network transformers in service with other insulating fluids in the main tank and high voltage switch. Also, the termination compartment of a high voltage switch may contain insulating fluids or compounds which may be PCB contaminated. For these reasons, it is essential to check the nameplates for each network transformer to identify all of the insulating fluids.

Routine Inspection – <u>Energized</u>

1. Verify the transformer and high voltage switch data in Cascade.
2. Check the transformer for leaks. Report any leaks to supervision who will determine the corrective action to be taken.
3. Check the high voltage switch, including the termination compartment when applicable, for leaks. Report any leaks to supervision who will determine the corrective action to be taken.
4. Check the transformer for any discoloration.
5. Check the high voltage switch for any discoloration.
6. Check the transformer for corrosion.
7. Check the high voltage switch for corrosion.
8. Check the fluid level in the transformer using the gauge.
9. Check the fluid level in high voltage switch using the gauge. Note that a new high voltage switch has one compartment and the fluid level is obtainable. For an older high voltage switch with two compartments, the fluid level in the termination compartment is not obtainable.

10. Obtain the peak temperature, if the gauge has a drag hand, and present temperature of the fluid in the transformer from the gauge.
11. Observe the primary connections on the high voltage switch for any unusual conditions.
12. Ensure the valves are closed and there are no leaks.
13. Check the condition of the valve handles to ensure they are in good condition.
14. Ensure the transformer is grounded to the vault ground grid or vault ground rod, as applicable.
15. Check for the presence of anodes and the condition of their connections (in wet locations only).
16. Ensure the high voltage switch position nameplates and nomenclature are visible and secure. Clean or replace as necessary.

Routine Inspection – <u>De-Energized</u>

1. Obtain a fluid sample fro the transformer and replenish the fluid. Refer to TD202 to ensure compliance with ChemLab requirements.
2. Obtain a fluid sample from the high voltage switch and replenish the fluid.
3. Pressure test the transformer.
4. Pressure test the high voltage switch.
5. Submit the fluid samples for testing. Follow the ChemLab oil sampling process to perform this correctly.
6. Ensure the high voltage switch handle operates properly.

<u>Failure Finding</u>

A failure report shall be completed for any network transformer failure, submitted to the equipment failure reporting system used by your region and placed in “To Eng” status for review by Distribution Standards.

Routine Maintenance – <u>Engergized</u> NUMM 6.30

1. Verify cables are properly supported and that the supports and hangers are in good condition.
2. Check the fluid level in the transformer using the liquid level gauge. If there is no oil indication, stop the job and notify Supervision.
   NOTE: Some transformers are equipped with magnetic mount oil gauges. These should be removed, cleaned and remounted to ensure their accuracy

3. Look for hazardous conditions such as falling concrete, concrete support blocks, bare conductors, discarded needles, rails, and other debris.
4. Verify the transformer nomenclature, if applicable.
    - Ensure the work order matches the transformer ID tag and that all identification and location numbers are correct.
    - Ensure the PCB tag is in place.
5. Ensure that the high voltage switch position nameplates and nomenclature are visible and secure. Clean or replace as necessary.
6. Record the as-found position of the high voltage switch.
7. Check for transformer leaks. Fix those that you can by tightening connections, etc. Report those leaks that can't be fixed at the time of this maintenance call.
8. Check the high voltage switch, including the termination compartment when applicable, for leaks. Report any leaks to supervision who will determine the corrective action to be taken.
9. Check the transformer and the high voltage switch for any abnormalities such as:
    - Severe rust – or corrosion from road salt
    - Physical damage from falling concrete, vandalism, failed mounting rails, etc.
10. Check the fluid level in high voltage switch using the gauge. Note that a new high voltage switch has one compartment ant the fluid level is obtainable. For an older high voltage switch with two compartments, the fluid level in the termination compartment *MAY NOT* be verified with the transformer energized.
11. Obtain the peak temperature, if the gauge has a drag hand, and present temperature of the fluid in the transformer from the gauge. Reset the drag hand (if installed) to the present reading.
12. Observe the primary connections on the high voltage switch for any unusual conditions. Look for cracked lead wipe, discolored high voltage connection, signs of heat, etc.
13. Ensure the valves are closed and that there are no leaks.
14. Check the condition of the valve handles to ensure they are in good condition.
15. Ensure the transformer and protector have separate grounds to the ground grid or vault ground rod. Do not rely on the mount support to act as a ground for the protector.
16. Check for the presence of anodes and the condition of their connections (if anodes are installed).

Routine Maintenance – De-Energized

NOTE: It is acknowledged that switching protocols vary among locations. It is the responsibility of the technician performing the maintenance work to either perform the following steps or to ensure that they have been performed.

1. De-energize the primary network cable.
2. Ensure the cable is de-energized.
    - For those installations in which the primary network cables have a rack in ground and test device, rack in the ground and test device and then perform a **live – dead – live** test with a noisy tester.
    - For those installations in which the primary network cables *do not* have a rack in ground test device, perform a **live – dead – live** test with an approved tester, then install grounds on the cable just above the pothead.
    - When the network transformer is de-energized, there will be no audible hum or vibration.
3. Ensure the network protector is in the Open position, in manual mode, and locked in order to prevent unintentional operation.
4. Record the as-found position of the high side switch.

    WARNING: You must obtain permission from Dispatch before operating the high side switch on a network transformer.

    WARNING: There have been instances in which the roll pin that connects the high side switch handle to the operating shaft have failed on Carte transformers. This has allowed the handle to move without actually rotating the operating shaft, thereby causing a false reading of the switch's position.
5. On **Carte** transformers, inspect the pin that connects the high side switch handle to the operating shaft. Replace it with a new, solid pin if it shows any signs of corrosion or damage.
6. Pressure-test the transformer main tank and the high voltage switch. Pressurize each with nitrogen to 3.0 PSI (or Manufacturer's recommendations) for 30 minutes.
    - If the test fails, repair the leaks and repeat the pressure test as required.
    - When the test passes, reduce the pressure to 0.25 PSI.
7. Obtain a fluid sample from the high voltage switch and replenish the fluid. Refer to TD202 to ensure compliance with ChemLab requirement.
8. Obtain a fluid sample from the transformer and replenish the fluid. Refer to TD202 to ensure compliance with ChemLab requirement.
9. Submit the fluid samples for testing. Refer to TD202 to ensure compliance with ChemLab requirements.

APPENDIX 13

UNDERGROUND NETWORK PROTECTORS

Network Protectors (NPs)

General Description

A network protector is an air circuit breaker and relay scheme (network protector mechanism) connected between the secondary side of a network transformer and the secondary network grid. The network protector is designed to perform the following three basic functions:

- Open on reverse power (flow of energy from the network into the transformer)
- Close on system conditions that allow for power flow into the secondary networks
- Close on a de-energized secondary network.

Incorporated in the design of the network protector are network protector fuses. These fuses provide back up protection should the network protector fail to open during faults on the primary feeder.

Network protectors fall under two categories – **Live Front** and **Dead Front** designs.

- Live front network protectors have exposed energized parts. The live front network protectors require the removal of the network protector fuses and transformer links to rack the breaker mechanism out of the enclosure to perform maintenance activities, (CM22 and MG8/9 styles). This type of network protector utilizes a motor close mechanism to close the network protector contacts.

- Dead front network protectors have all energized parts insulated or isolated. This type of protector uses a spring charge, to close the network protector contacts (CMD and CM52 styles). The spring is charged by a motor, which then releases the stored energy to close the protector contacts.

The maintenance requirements for the following network protectors are provided in separate sections for each model.

- CMD
- CM-22
- CM-52
- MG 8/9

Network Maintenance shall be performed in accordance with TD871.

Facilities/Equipment

Street and spot networks

CMD Routine Inspection

1. If the operations count is greater than 500 since the last inspection, consider scheduling a Major Maintenance and notify Protection & Controls.
2. Check and record the current readings on the network protector – or – if an AMR meter is installed, record its values.
3. Inspect for blown limiters.
4. Ensure the position control indicators and nomenclature are present and in good condition. Clean or replace as necessary.
5. Perform thermal imaging on the secondary terminals of the network protector.
6. Clean the exterior of the protector enclosure.
7. Visually inspect the network protector for abnormal conditions (moisture entry, blown fuses, etc.).
8. Check the pressure of the network protector enclosure and add nitrogen when necessary.
9. Check the protector and its enclosure for rust or corrosion and perform any touch up as necessary.

CMD Major Maintenance

1. Inspect transformer secondary bushings and throat for signs of oil leaks.
2. Check the manual operation of protector.
3. Inspect the counter and position indicator for proper operation.
4. Inspect for loose, missing or damaged hardware, resistors, terminals coils, etc.
5. Ensure insulating caps are in place and in good condition.
6. Inspect for damaged or contaminated barrier boards.
7. Inspect and clean the arc chutes, as necessary.
8. Inspect the main and arcing contacts for overheating, and proper clearances/contact pressure.
9. Perform an insulation resistance test (Megger).
10. Perform contact resistance tests (Ductor).
11. Perform Relay Tests:
    - Electromechanical relay
        - Master and phasing relay over-voltage closing test
        - Master relay reverse current trip test
    - Solid State/Microprocessor-based relay tests
        - Over voltage closing test
        - Reverse current trip test

12. On 480 Volt spot networks utilizing a GFI and lockout, verify lockout operation.

CM-22 Routine Inspection

1. If the operations count is greater than 500 since the last inspection, consider scheduling a Major Maintenance and notify Protection & Controls.
2. Check and record the current readings on the network protector – or – if an AMR meter is installed, record its values.
3. Inspect for blown limiters.
4. Ensure the position control indicators and nomenclature are present and in good condition. Clean or replace as necessary.
5. Perform thermal imaging on the secondary terminals of the network protector.
6. Clean the exterior of the network protector enclosure.
7. Visually inspect the network protector for abnormal conditions (moisture entry, blown fuses, etc.).
8. Check the pressure of the network protector enclosure and add nitrogen when necessary.
9. Check the protector and its enclosure for rust or corrosion and perform any touch up as necessary.

CM-22 Major Maintenance

1. Inspect transformer secondary bushings and throat for signs of oil leaks.
2. Check the manual operation of the protector.
3. Inspect the counter and position indicator for proper operation.
4. Inspect for loose, missing or damaged hardware, resistors, terminals coils, etc.
5. Inspect for damaged or contaminated barrier boards.
6. Verify that the insulating caps are in place.
7. Inspect the bumper to ensure it is in place.
8. Inspect the air dashpot, if so equipped, and clean and lubricate as necessary.
9. Check current-carrying parts and their adjacent insulating boards and materials for signs of overheating.

10. Inspect and clean the arc chutes, as necessary. **NOTE:** Follow hazardous material handling precautions as some units may contain asbestos.

11. Inspect the main and arcing contacts for excessive pitting overheating and for proper clearances. Clean and lubricate these parts, as required.

12. Inspect the auxiliary switches and motor contactors for contact wear.

13. On 480 volt spot networks utilizing a GFI and lockout, verify the lockout operation.

14. Inspect and clean the motor centrifugal governor if equipped with a 2-wire motor.

15. Inspect the motor and brushes for wear and lubricate as necessary.

16. Perform insulation resistance tests (Megger).

17. Perform contact resistance tests (Ductor).

18. Perform Mechanical Tests:

    - Full voltage close and open operation.
    - Verify and adjust the minimum motor close.
    - Verify and adjust the minimum trip voltage.
    - Verify and adjust the motor control device pick up.

19. Perform Relay Tests:
    - Electromechanical relay
        - Master and phasing relay over-voltage closing test
        - Master relay reverse current trip test
    - Solid State/Microprocessor-based relay tests
        - Over-voltage closing test
        - Reverse Current trip test

20. Check the manual operation of the protector.

21. Visually inspect the door and window gaskets for signs of damage or degradation. Replace as necessary.

CM-52 Routine Inspection

1. If the operations count is greater than 500 since the last inspection, consider scheduling a Major Maintenance and notify Protection & Controls.

2. Check and record the current readings on the network protector – or – if an AMR meter is installed, record its values.
3. Inspect for blown limiters.
4. Ensure the position control indicators and nomenclature are present and in good condition. Clean or replace as necessary.
5. Perform thermal imaging on the secondary terminals of the network protector.
6. Clean the exterior of the network protector.
7. Visually inspect the network protector for abnormal conditions (moisture entry, blown fuses, etc.).
8. Inspect the Indicating Diagnostic Module (IDM) for indication of weak or failing components.
9. Check the protector and its enclosure for rust or corrosion and touch up as necessary.
10. Check the pressure of the network protector enclosure and add nitrogen when necessary.

CM-52 Major Maintenance

1. Inspect transformer secondary bushings and throat for signs of oil leaks.
2. Inspect the counter and position indicator for proper operation.
3. Inspect for loose, missing or damaged hardware, resistors, terminals coils, etc.
4. Inspect for damaged or contaminated barrier boards.
5. Inspect and clean the arc chutes, as necessary.
6. Inspect the main and arcing contacts for overheating.
7. Inspect the contact wear indicator and clean the contacts.
8. Perform an insulation resistance test (Megger).
9. Perform contact resistance tests (Ductor).
10. Check the mechanical operation of the protector.
11. Perform Relay Tests:
    - Microprocessor-based relay tests:
        - Over-voltage closing test
        - Reverse current trip test
12. Perform visual inspection of the door and window gaskets for signs of damage or degradation. Replace as necessary.
13. On 480 Volt spot networks utilizing a GFI and lockout, verify lockout operation.

MG 8/9 Routine Inspection

1. If the operations count is greater than 500 since the last inspection, consider scheduling a Major Maintenance and notify Protection & Controls.

2. Check and record the current readings on the network protector – or – if an AMR meter is installed, record its values.
3. Inspect for blown limiters.
4. Ensure the position control indicators and nomenclature are present and in good condition. Clean or replace as necessary.
5. Perform thermal imaging on the secondary terminals of the network protector.
6. Clean the exterior of the network protector.
7. Visually inspect the network protector for abnormal conditions (moisture entry, blown fuses, etc.).
8. Check the pressure of the network protector enclosure and add nitrogen when necessary.
9. Check the protector and its enclosure for rust or corrosion and touch up as necessary.

MG 8/9 Major Maintenance

1. Inspect transformer secondary bushings and throat for signs of oil leaks.
2. Visually inspect the door and window gaskets for signs of damage or degradation. Replace them as necessary.
3. Check the manual operation of the protector.
4. Inspect the counter for proper operation.
5. Inspect for loose, missing or damaged hardware, resistors, terminals coils, etc.
6. Inspect for damaged or contaminated barrier boards.
7. Check current-carrying parts and their adjacent insulating boards and materials for signs of overheating.
8. Inspect the auxiliary and motor contactors for contact wear.
9. Inspect and clean the arc chutes, as necessary. NOTE: Follow hazardous material handling precautions as some units may contain asbestos.
10. Inspect the main, arcing, and intermediate contacts for excessive pitting and for proper clearances. Clean and lubricate these parts, as required.
11. Inspect and clean the motor torque brake.
12. Inspect the motor and brushes for wear and lubricate, as necessary.
13. Check the gearbox oil and refill as necessary.
14. Inspect and lubricate the secondary trip latch.
15. Perform insulation resistance tests (Megger).
16. Perform contact resistance tests (Ductor).
17. Perform Mechanical Tests:
    - Perform full voltage open and close operation.

- Verify and adjust the minimum motor close.
- Verify and adjust the minimum trip voltage.
- Verify and adjust the motor control device pick up.
- Verify trip free operation.

18. Perform Relay Tests:
    - Electromechanical relay
        - Master and phasing relay over-voltage closing test
        - Master relay reverse current trip test
    - Solid State/Microprocessor-based relay tests
        - Over-voltage closing test
        - Reverse current trip test
19. On 480 Volt spot networks utilizing a GFI and lockout, verify lockout operation.

APPENDIX 14

UNDERGROUND SYSTEM – CABLES

Underground Cables –

General Description – NUMM 5.49

This section covers primary and secondary cable used in conventional underground (UG) and secondary network distribution systems. The cables used in conventional underground and secondary networks are typically installed in manholes, vaults and concrete encased duct banks.

Primary cables used in the underground are typically of one of the following construction types:

- Paper Insulated Lead Covered (PILC)
- Ethylene Propylene Rubber (EPR)
- Cross Link Polyethylene (XLPE)
- Tree Retardant Cross Link Polyethylene (TRXLPE)
- High Molecular Weight Polyethylene (HMPE)

Secondary network cables are typically constructed of copper conductors with a variety of insulation types ranging from paper insulated, varnished cambric, and rubber. The Secondary cable grid is made up of a number of parallel secondary cables of typically 4/0AWG or 500 kcmil copper conductors. Cable limiters are used to isolate faulted secondary cables allowing the remaining parallel cables to supply the grid or load.

Secondary cables used in radial distribution systems are constructed of copper or aluminum conductors are not protected by cable limiters.

Facilities/Equipment

Underground cable and associated equipment, i.e. limiters, splices, etc.

Condition Monitoring

Repair any defects found during Routine Inspections and during the course of normal work.

Routine Inspection

1. Inspect primary cables splices and terminations for the following abnormal conditions:
    a. Oil leaks, soft spots and insulation swelling
    b. Cracked or corroded lead sheaths
    c. Damaged Fireproofing
    d. Poor ground connections
    e. Collapsed or bulged cables or splices
    f. Missing Tags

g. Physical Damage, sharp bends and excessive tension

2. Inspect manhole grounds.
3. Perform Infrared Inspection to identify poor connections and potential problems.
4. Inspect the duct shields and install or replace them as necessary.
5. Inspect secondary and service cables for the following:
   - Ensure connections are clean and tight.
   - Open Limiters
   - Verify that electrical continuity is good.
   - Insulation Condition
   - Sheath Voltage
6. Ensure all cables are properly supported and resting on insulators. Report any cables that have shifted from load cycling, traffic vibration, etc.
7. Check the condition of fault indicators, if present. Replace the fault indicators every ten years.

Failure Finding

Failure finding task are used to indentify defects in UG cables and related equipment. Perform all repairs that can be done at the time of inspection. Major repairs need to be reported and/or scheduled.

Conventional Underground Cables – NUMM 6.49

1. Perform touch potential testing as described on section 5.62 NU Maintenance Manual.
2. Ensure there are no obstructions and that the area is accessible. Record the presence of any unwanted barriers (such as fences or vegetation) that obstruct the inspection, operation, or maintenance of equipment. If vegetation needs to be removed, contact the customer.

   CAUTION: Before replacing missing tags, BE SURE you have the correct information to put o the tag. Use appropriate procedures and circuit maps/prints for identification.
3. Ensure standard signs, cable tags, and labels are in place in good condition. Replace missing or plastic cable ID tags with brass tags.
   NOTE: Not all operating companies use the brass tags.
4. Use the equipment prints/schematics/circuit maps to verify the actual field conditions, i.e. transformer size, etc.
5. Ensure safety and security equipment (such as brass locks and penta bolts) are in place and in good working condition. Check for signs of vandalism.

6. Perform an infrared inspection to check for heat anomalies on primary connections, secondary connections and accessories, as applicable.

NOTE: Perform the Infrared (IR) inspection using an infrared camera. If an infrared camera is not available, a temperature reading tool, such as the Fluke 63 (SC 0435572) may be used to take spot temperature readings of the equipment in place of the IR inspection.

Primary cables and connecting devices include:

- PILC Splices
- Premolded Splices
- Heat Shrink Splices
- Cold Shrink Splices
- 200 AMP Load Break Elbows
- 600 AMP Load Break Elbows

Secondary cables and devices to check include:

- Mains
- Services
- Bus Bars
- Bus Limiters
- Line Limiter
- Molded Crabs (both limited and non-limited)
- Network Transformer Secondary Connection
- Secondary and Service Splices

7. Ensure that all grounds, neutral, and drain (or bleed) wire connections, such as primary, secondary, etc. are in place and in good condition.
8. Inspect primary cables splices and terminations for the following abnormal conditions:

- Oil leaks, soft spots and insulation swelling
- Cracked or corroded lead sheaths
- Damaged fireproofing
- Poor connections, signs of arcing/tracking
- Collapsed or bulged cables
- Bulged splices
- Physical damage, sharp bends and excessive tension
- 250S Splices (Note splices for future replacement.)

9. Inspect secondary and service cables for the following:
   - Ensure connections are clean and tight.
   - Insulation condition
10. Ensure all fault indicators (as applicable) are in good condition and working. Replace every ten years or as necessary.
11. Check the mounting hardware to ensure that it is stable and free of corrosion.
12. Ensure all covers or grates are securely locked or bolted in position.
13. Ensure all cables are properly supported and resting on insulators. Report any cables that have shifted from load cycling, traffic vibration, etc.
14. Record into Cascade or on the appropriate inspection form, all deficiencies found during inspections including the completion date of those items that were corrected.
15. Notify Supervision of any safety concerns and any conditions that require correction.

Risers

1. Perform touch potential testing as described on section 5.62 NU Maintenance Manual.
2. Ensure there are no obstructions and that the area is accessible. Record the presence of any unwanted barriers (such as fences or vegetation) that obstruct the inspection, operation, or maintenance or equipment. If vegetation needs to be removed, contact the customer.

CAUTION: Before replacing missing tags, BE SURE you have the correct information to put on the tag. Use appropriate procedures and circuit maps/prints for identification.

3. Ensure standard signs, cable tags, and labels are in place and in good condition. Replace any that are missing or have become damaged or faded from age.
4. Use the equipment prints/schematics/circuit maps to verify the actual field conditions, i.e., transformer size, etc.
5. Perform an infrared inspection on primary connections, secondary connections and accessories, as applicable.
6. Ensure that all grounds, neutral and drain (or bleed) wire connections, such as primary, secondary, etc. are in place and in good condition.
7. Ensure that primary/secondary equipment, such as bushings, insulators, arresters, elbows, elbow arresters, terminators, connectors, cable taps, dead-end receptacles are in good condition.

Check for signs of arcing, tracking, chipping, stress, etc. for all connections.

8. Visually inspect primary cables for the following abnormal conditions:
    - Oil leaks, soft spots and insulation swelling
    - Cracked or corroded lead sheaths
    - Collapsed or bulged cables
    - Bulged splices
    - Physical damage, sharp bends and excessive tension
9. Record the presence of older style GE terminations for possible replacement
10. Record the presence of porcelain lightning arresters for possible replacement.
11. Inspect secondary and service cables for the following:
    - Ensure connections are clean and tight.
    - Insulation condition
12. Check the mounting hardware to ensure that it is stable and free of corrosion.
13. Inspect the general condition of the riser and ensure it is secured to the pole.
14. Ensure the riser pole stencils are present and that the stenciled fuse size agrees with the circuit map/prints.
15. Record into Cascade or on the appropriate inspection form, all deficiencies found during inspections including the completion date of those items that were corrected.
16. Notify Supervision of any safety concerns and any conditions that require corrections.

Network Cables

1. Perform touch potential testing as described on section 5.62 of the NU Maintenance Manual.
2. Ensure there are no obstructions and that the area is accessible. Record the presence of any unwanted barriers (such as fences or vegetation) that obstruct the inspection, operation, or maintenance of equipment. If vegetation needs to be removed, contact the customer.

CAUTION: Before replacing missing tags, BE SURE you have the correct information to put on the tag. Use appropriate procedures and circuit maps/prints for identification.

3. Ensure standard signs, cable tags, and labels are in place and in good condition. Replace missing or plastic cable ID tags with brass tags.
4. Use the equipment prints/schematics/circuit maps to verify the actual field condition, i.e., transformer size, etc.
5. Ensure safety and security equipment (such as brass locks and penta bolts) are in place and in good working order. Check for signs of vandalism.
6. Perform an infrared inspection on primary connections, secondary connections and accessories, as applicable.
7. Ensure that all grounds, neutral, and drain (or bleed) wire connections, such as primary, secondary, etc. are in place and in good condition.
8. Inspect primary cables splices and terminations for the following abnormal conditions:

   • Oil Leaks, soft spots and insulation swelling
   • Cracked or corroded lead sheaths
   • Damaged fireproofing
   • Poor ground connections
   • Collapsed or bulged cables
   • Bulged splices
   • Physical damage, sharp bends and excessive tension

9. Inspect secondary and service cables for the following:

   - Ensure connections are clean and tight.
   - Insulation condition

10. Check the mounting hardware to ensure that it is stable and free of corrosion
11. Ensure all covers or grates are securely locked or bolted in position.
12. Ensure all cables are properly supported and resting on insulators. Report any cables that have shifted from load cycling, traffic vibration, etc.
13. Inspect for blown/open limiters where applicable. Use a clamp or rope style current transformer (CT) around the conductors of each phase.
14. Record into Cascade or on the appropriate inspection form, all deficiencies found during inspections including the completion date of those items corrected.
15. Notify Supervision of any safety concerns and any conditions that require correction.

Sector Cabinets (Metal Switch Enclosures)

NOTE: Inspecting the sector cabinets is not required at this time if it is a regular part of the Direct Buried inspection.

1. Perform touch potential testing as described in section 5.62 of the NU Maintenance Manual.
2. Inspect the equipment for deterioration and proper grading.
3. Ensure there are no obstructions and that the area is accessible. Record the presence of any unwanted barriers (such as fences or vegetation) that obstruct the inspection, operation, or maintenance of equipment. If vegetation needs to be removed, contact the customer

CAUTION: Before placing missing tags, BE SURE you have the correct information to put on the tag. Use appropriate procedures and circuit maps/prints for identification.

4. Ensure standard signs, cable tags, and labels are in place and in good condition. Replace missing tags or plastic cable ID with brass tags.
5. Use the equipment prints/schematics/circuit maps to verify the actual field conditions, i.e., transformer size, etc. Verify nomenclature on the transformer against the circuit map. Record any discrepancies between the map and the nomenclature for revision.
6. Ensure safety and security equipment (such as brass locks and penta bolts) are in place and in good working condition. Check for signs of vandalism.
7. Perform an infrared inspection on primary connections, secondary connections and accessories, as applicable.
8. Ensure that all grounds, neutral, and drain (or bleed) wire connections, such as primary, secondary, etc. are in place and in good condition. Refer to Undergrounds Standards sections 56 and 58 for grounding requirements.
9. Ensure that primary/secondary equipment, such as bushings, insulators, arresters, elbows, elbow arresters, terminators, connectors, cable taps, dead-end receptacles are in good condition. Check for signs of arcing, tracking, chipping, stress, etc. for all connections.

NOTE: Treat load break elbows (if present) with missing test caps as “live front” until the elbow test caps are replaced per manufacturer’s recommendations. Tag the transformer as needing repair until the elbow test caps are replaced.

10. Note the absence of elbow arrestors that should be installed for possible installation at a later date.
11. Inspect primary cables for the following abnormal conditions:

    - Oil leaks, soft spots and insulation swelling
    - Cracked or corroded lead sheaths
    - Damaged fireproofing
    - Collapsed or bulged cables
    - Bulged splices
    - Physical damage, sharp bends and excessive tension
    - 250S Splices (Note for future replacement.)

12. Ensure all fault indicators (as applicable) are in good condition and working. Replace every ten years or as necessary.
13. Ensure protective bumpers are in place and in good condition, if applicable. Report damaged ones as required to the responsible parties.
14. Ensure the transformer/enclosure is set properly on its concrete slab/pad.
15. Visually check for rust and corrosion.
16. Inspect the condition of the fence, for fenced-in enclosures.
17. Check the mounting hardware to ensure that it is stable and free of corrosion.
18. Record into Cascade or on the appropriate inspection form, all deficiencies found during inspections including the completion date of those items corrected.
19. Notify Supervision of any safety concerns and any conditions that require correction.
    - **NOTE:** Any enclosure that cannot be locked due to rusted or broken locking hardware must be secured to prevent public entry. If the transformer cannot be secured, replace it immediately.
    - Entry into the enclosure by the public must be prevented. Any hole from corrosion or other damage must be blocked to prevent intrusion and possible harm to the public.

APPENDIX 15

UNDERGROUND SYSTEM – TRANSFORMERS

Underground Transformers

General Description – NUMM 5.55

Loads fed from the underground system that are not tied to the network grid are supplied from either single phase transformers, banks of single phase transformers, or three-phase transformer units. These pad-mounted transformers are usually of an underground or submersible type. Transformers that were installed years ago had various types of cable entrances to accommodate the various types of insulated cables that were installed. They could be fed from underground cables or from a riser. The transformers were generally protected on the high voltage side with either external fuses or internal fuses. The system voltages were generally 5 kV and below. Many of these transformers have been replaced over the years as 5 kV and below systems have been converted to systems ranging from 15 kV to 35 kV. Single phase transformers installed in these conversion areas and in new underground areas are the standard manhole or vault type transformer. These submersible transformers have internal fuses on the high voltage side and secondary breakers on the low voltage side. Industry standard rubber molded products are used to connect the transformers to insulated primary cables made of newer materials.

Routine Inspection – Energized

1. Verify the transformer kVA, transformer number, and serial number data. Repair or replace any numbering, as required.
2. Ensure equipment nomenclature and status indicators are present and in good condition. Clean or replace as required.
3. Check the transformer for leaks.
4. Check the transformer for any discoloration.
5. Check the transformer for corrosion.
6. Check the oil level in transformer, when practical.
7. Visually check the primary connections on the high voltage side of the transformer for any unusual conditions.
8. Visually check any accessories on the high voltage side of the transformer for any unusual conditions.
9. Visually check the secondary connections on the low voltage side of the transformer for any unusual conditions.
10. Visually check any accessories on the low voltage side of the transformer for any unusual conditions.
11. Ensure the transformer is grounded to the manhole or vault ground grid.

12. Check for the presence of anodes and the condition of their connections.
13. Infrared check primary connections, secondary connections and accessories, if applicable.

Failure Finding

Failures of Underground Transformers shall be documented in the equipment failure reporting system used by your region. A failure report shall be completed for any underground transformer failure and placed in “To Eng” status for review by Distribution Standards.

Maintenance – NUMM 6.55

Transformers – Dead Front

1. Perform touch potential testing as described in section 5.62 of the NU Maintenance Manual.
2. Inspect the equipment for deterioration and proper grading.
3. Ensure there are no obstructions and that the area is accessible. Record the presence of any unwanted barriers (such as fences or vegetation) that obstruct the inspection, operation, or maintenance of equipment. If vegetation needs to be removed, contact the customer.
4. Ensure the transformer includes spare fuses (if practiced by your operating company).

CAUTION: Before replacing missing tags, BE SURE you have the correct information to put on the tag. Use appropriate procedures and circuit maps/prints for identification.

5. Ensure standard signs, cable tags, and labels are in good condition. Replace missing cable ID tags with brass tags. Plastic tags may be used in addition to the brass tags.
6. Use the equipment prints/schematics/circuit maps to verify the actual field conditions, i.e., transformer size, etc.
7. Ensure safety and security equipment (such as brass locks and penta bolts) are in place and in good working condition. Check for signs of vandalism.
8. Ensure that all grounds, neutral, and drain (or bleed) wire connections, such as primary, secondary, etc. are in place and in good condition. Refer to Underground Standards sections 56 and 58 for grounding requirements.

9. Ensure that primary/secondary equipment such as bushings, insulators, arresters, elbows, elbow arresters, terminators, connectors, cable taps, dead-end receptacles are in good condition. Check for signs of arcing, tracking, chipping, stress, etc. for all connections.

   NOTE: Treat load break elbows (if present) with missing test caps as “live front” until the elbow test caps are replaced according to manufacturer’s recommendations. Tag the transformer as needing repair until the elbow test caps are replaced.
10. Ensure all fault indicators (as applicable) are in good condition and working. Replace them every ten years or as necessary.
11. Ensure protective bumpers are in place and in good condition, if applicable. Report damaged ones as required to the responsible parties.
12. Ensure the transformer/enclosure is set properly on its concrete slab/pad.
13. Inspect equipment for signs of oil leads and notify Supervision if any are found.
14. Visually check the oil level, if practical.
15. Ensure deflector plates are installed, as required for the specific equipment type (varies by operating company). Deflector plates are shields installed over some submersible transformers.
16. Inspect the condition of the fence, for fenced – in enclosures.
17. Check for the proximity of a catch basin or surface water within 50 feet of the installation and record if this condition exists.
18. Check the nameplate for presence of PCBs within the equipment. This will be indicated by a blue or green label. Note the presence of PCBs or the absence of a sticker indicating this information.
19. Check for the presence of anodes and the condition of their connections, as applicable for three phase transformers or network protector installation in below grade vaults. See Underground Standards sections 013 and 015-016 for anode requirements.
20. Perform an infrared inspection on primary connections, secondary connections and accessories.
21. Ensure all gauges are in good condition and working, if present. These may include those for temperature, oil level, etc.
22. Note the absence of any required elbow arresters for possible installation at a later date.
23. Notify Supervision of any safety concerns and any conditions that require correction.

NOTE: Any transformer that cannot be locked due to rusted or broken locking hardware must be secured to prevent public entry. If the transformer cannot be secured, replace it immediately.

- Entry into the transformer must be prevented. Any hole from corrosion or other damage must be blocked to prevent intrusion and possible harm to the public.

24. Utilize Cascade, the inspection reporting process, or the failure reporting system used by your operating company to record deficiencies indentified during inspections, including completion dates and corrective items.

Transformers – Live Front

Note: Special precautions need to be taken when performing inspections on Live Front transformers. Review the NU Employee Safety & Health Handbook for specific safety requirements and operating company specific procedures.

1. Perform touch potential testing as described in section 5.62 of the NU Maintenance Manual.
2. Inspect the equipment for deterioration and proper grading.
3. Ensure there are no obstructions and that the area is accessible. Record the presence of any unwanted barriers (such as fences or vegetation) that obstruct the inspection, operation, or maintenance of equipment. If vegetation needs to be removed, contact the customer.
4. Ensure the transformer includes spare fuses (if practiced by your operating company).
5. Ensure standard signs, and labels are in good condition.
6. Use the equipment prints/schematics/circuit maps to verify the actual field conditions, i.e., transformer size, etc.
7. Ensure safety and security equipment (such as brass locks and penta bolts) are in place and in good working condition. Check for signs of vandalism.
8. Ensure electrical barriers are in place.

NOTE: Removal of barriers for the purpose of performing an inspection in the primary compartment shall be done using appropriate PPE in accordance with Safety rules/requirements and operating company specific procedures.

9. Ensure that all grounds, neutral, and drain (or bleed) wire connections, such as the primary, secondary, etc. are in place and in good condition. Refer to Underground Standards sections 56 and 58 for grounding requirements.
10. Ensure that primary/secondary equipment such as bushings, insulators, arresters, elbows, elbow arresters, terminators, connectors,

cable taps, dead-end receptacles are in good condition. Check for signs of arcing, tracking, chipping, stress, etc. for all connections.

11. Ensure all fault indicators (as applicable) are in good condition and working. Replace them every ten years or as necessary.
12. Ensure protective bumpers are in place and in good condition, if applicable. Report damaged ones as required to the responsible parties.
13. Ensure the transformer/enclosure is set properly on its concrete slab/pad.
14. Inspect equipment for signs of oil leaks and notify Supervision if any are found.
15. Visually check the oil level, if practical.
16. Ensure deflector plates are installed, as required for the specific equipment type (varies by operating company). Deflector plates are shields installed over some submersible transformers.
17. Inspect the condition of the fence, for fenced-in enclosures.
18. Check for proximity of a catch basin or surface water within 50 feet of the installation and record if this condition exists.
19. Check the nameplate for presence of PCBs within the equipment. This will be indicated by a blue or green label. Note the presence of PCBs or the absence of a sticker indicating this information.
20. Check for the presence of anodes and the condition of their connections, as applicable for three phase transformer or network protector installation in below grade vaults. See Underground Standards sections 88, 013, 015-016 for anode requirements.
21. Perform and infrared inspection on primary connections, secondary connections and accessories.
22. Ensure all gauges are in good condition and working, if present. These may include those for temperature, oil level, etc. Record any defects that are found.
23. Notify Supervision of any safety concerns and any conditions that require correction.

    NOTE: Any transformer that cannot be locked due to rusted or broken locking hardware must be secured to prevent public entry. If the transformer cannot be secured, replace it immediately.
    - Entry into the transformer must be prevented. Any hole from corrosion or other damage must be blocked to prevent intrusion and possible harm to the public.

24. Use the pressure relief valve to eliminate any pressure within the transformer tank.
25. Utilize Cascade to record deficiencies indentified during inspections, including completion dates and corrective items.

APPENDIX 16

STREET LIGHTING

Streetlights and Floodlights

General Description – NUMM 5.48

Streetlight and Floodlight maintenance includes the Time-Directed (preventive) group relamping program and Condition-Based maintenance which includes the troubleshooting and repair of lights that have failed. This document provides the intervals for time-directed maintenance for both large and small municipalities.

- The term "Lamp" refers to the bulb that actually illuminates.
- The term "fixture" refers to streetlights and floodlights. It includes the assembly into which the lamp and photoelectric cell are installed.

Facilities/Equipment

Streetlights and Floodlights

NOTE 1: Municipalities with greater than 1000 street lights will be group re-lamped on a 5 or 6 year cycle (depending on specific operating company requirements.

NOTE 2: Municipalities with less than 1000 fixtures will be managed through the repair process unless they reach the peak repair rate described below:

- Municipalities with 750 – 1000 street lights will be group re-lamped when the repair rate reaches 10% (an average of 8.3 repairs per month).
- Municipalities with 500 – 700 street lights will be group re-lamped when the rate reaches 12% (an average of 7.5 repairs a month).
- Municipalities with 250 – 500 street lights will be group re-lamped when the repair rate reaches 14% (an average of 6 repairs a month).
- Municipalities with 1 – 250 street lights will be group re-lamped when the repair rate reaches 19% (an average of 4 repairs a month).

Maintenance Categories

Time – Directed

For CL&P a 5 year cycle is a parameter of the Group Relamping program in accordance with TD 080. Lamps are replaced on a scheduled basis before they fail in order to provide continuous service and eliminate the cost of emergency repairs.

Conditioned – Based

See TD 863 for details on troubleshooting streetlight problems and the handling of waster materials related to relamping.

Failure Finding

1. Report each fixture that has been disconnected at the end of the work day to your Supervisor (district line groups) or to the Street Light Planner (Street Light Mechanics and Re-lampers).
2. Keep a defective fixture at the area work center if it is less than 5 years old; otherwise, discard the fixture in a designated recycling container. Inside of the fixture there is a label with the date code on it.
3. Any failures found during group relamping should be recorded on the relamping spreadsheet and provided to the Supervisor – Street Light Maintenance or the Street Light Account Executive for follow-up. Refer to TD 080
4. The responsibility for cost of repair of lighting fixtures varies with each operating company. Documentation specific to each company should be referenced where appropriate.

Metal Streetlight Poles

General Description – NUMM 5.52

This Inspection and Maintenance procedure pertains to metal streetlight poles owned by Northeast Utilities and is intended to insure structural integrity and enhance public safety.

In urban areas where electric distribution is underground (direct buried or conduit), a tapered aluminum alloy pole is the current Northeast Utilities standard. Decorative streetlight poles (also aluminum), steel streetlight poles, and concrete bases (poured or precast) and are covered by this procedure.

This procedure does not cover the inspection and maintenance of the luminaire or its components (bulbs, photo cells, etc.), which are covered in another chapter.

Time Directed

Routine Inspections

- Pole Inspections
- Concrete base and anchor bolt inspection

Failure Finding

Report any findings of failed or degraded materials on the appropriate form.

METAL STREETLIGHT POLE INSPECTION – NUMM 6.52

Pole Inspection

1. Test all surfaces that may be accessible to the public, according to requirements of numm instruction 6.62 and work practice M4-WP-3038.
2. Ensure badge and numbers are correct according to DTR Section 43.062. Replace missing characters only if you are sure of the correct nomenclature. Otherwise, record the location for a future visit.
3. Handhole covers and bolts. Ensure all covers are in place. Replace any missing hardware.
4. Check the pole and base for cracks.
5. Check for excessive rust on steel poles.

Concrete Base and Anchor Bolt Inspection

6. Replace any missing fasteners.
7. Ensure all hardware is in good condition. Replace as necessary.
8. Cracking/flaking concrete. Note any conditions that require correction.

APPENDIX 17

UNDERGROUND VAULTS AND MANHOLES

Underground Vaults & Manholes

General Description – NUMM 5.59

This chapter provides the requirements for inspecting and maintaining company-owned underground vaults and manholes that contain company -owned equipment in order to ensure they provide a safe working environment for those who enter the facilities, protect the equipment from water or debris that may enter the vault/manhole, and to assure public safety.

The underground equipment includes transformers, cables, and switchgear that will be maintained in accordance with the appropriate chapter of the Distribution Maintenance Program.

Facilities/Equipment

Underground Vaults or Manholes

C1 Vaults/Manholes – Major Maintenance (**Note 1**)	1st Priority
C2 Vaults/Manholes – Major Maintenance (**Note 1**)	2nd Priority
C3 Vaults/Manholes – Major Maintenance (**Note 1**)	3rd Priority
C4 Vaults/Manholes – Major Maintenance (**Note 1**)	4th Priority

Note 1 The condition of the vaults will determine their next maintenance interval as follows:

- Major defects found during a *planned entry* inspection may be cause to classify the structure as described below and require it to receive more frequent inspections until repairs can be made. A planned entry is any entry being made to a vault or manhole for the purpose of performing scheduled maintenance on any piece of equipment located within the vault or manhole.

Conditions C1 – C4 represent underground vaults and manholes as follows:

- C1 –. A Structural Engineer will recommend repair/replacement/re-inspection as soon as possible, not to exceed one year. Manhole requires repairs within one year's time.
- C2 – Deterioration Noted. This manhole exhibits structural degradation that is not likely to cause failure within the next year. Review within one year by Structural Engineer to determine recommended repair/replacement/re-inspection schedule.
- C3 – Manhole exhibits structural degradation but failure is not likely within the next five years. This structure should be reviewed by a Structural Engineer to recommend re-inspection/repair/replacement schedule.
- C4 – Re-inspect at the next planned entry.

Note 2 All manholes and vaults will receive an inspection during each planned maintenance entry. Any vaults (both network and non-network) may be inspected more frequently based on their history or maintenance requirements. In no case shall the period between inspections exceed ten years.

Note 3 Manholes and vaults will be cleaned as required based on inspection results. Any manholes or vaults may be cleaned more frequently based on their history or maintenance requirements.

CONDITION-BASED

Cleaning underground vaults and manholes shall be performed at the frequency required to ensure the safety of those workers who enter the facilities and the protection of the equipment within them.

Routine Inspections of vaults and manholes are visual inspections of the structure itself. The structures shall be inspected coincident with the inspection of installed equipment in the vault or manhole.

Cleaning – As Required

1. Ensure the vault/manhole is free from:
   - Water or other liquids
   - Salt
   - Dirt or other debris that could affect equipment operation or maintenance.

Routine Inspection – NUMM 6.59

1. Check for open work orders (such as leaking splices) for this location that may indicate unsafe conditions or that my present the opportunity for combining maintenance at this or adjacent vaults.
2. Check for objects blocking ventilation.
   - There must be at leas 3 sq. inches of clear opening / kva as a minimum (N.E.C. requirement). If it appears that less than the required amount of ventilation is present, note this condition so the issue can be resolved.
3. Clean all dirt, salt, and other debris that has accumulated since the previous Routine Inspection.
4. Check for objects blocking ventilation. Remove these as necessary.
5. Clear foreign materials from the vault/manhole entrance and the vault/manhole, as required.
6. Check the drains for blockage and report any adverse conditions that can't be fixed at the time of the inspection.
7. Inspect the walls and ceiling. Report any signs of cracking or flaking concrete, exposed reinforcing steel, rusty I-beams, etc. into Cascade or to Supervision, as appropriate.
8. Inspect the vault grating for:
   - Broken hinges or other hardware defects
   - Broken or cracked welds
   - Excessive wear to bearing bars (lids and grates)
   - Broken rivets
9. Inspect the vault for excessive mid-span deflection of walls, floors, lids and supports.
10. Inspect frames to ensure:
    - Their corners are either welded or bolted together.
    - They are seated properly in a polymer mortar base that is fastened firmly on top of the wall.
11. Inspect rack supports (cable, equipment, etc) for damage and/or tripping hazards.
12. Inspect frames for signs of snow plow impacts.
13. Note all repairs that need attention.
14. Report any serious defects found or suspected to initiate a Civil Engineering inspection.
15. Take photographs, when appropriate, of conditions needing repair.
    - NOTE: Place a ruler adjacent to objects being photographed so the scale can be determined visually.

Major Maintenance

1. Correct any conditions found and noted during the Routine Inspection.
2. Inspect Beam Pockets to ensure:
   - Sufficient bearing surface
   - Beams lay flat in the pocket, with no torsion
   - Shims, concrete, and bearing surfaces are in good condition
   - Beams have proper embedment into the pocket
3. Ensure grate frames and removable slabs are in uniform contact with the top of the support beams.
4. Check pulling eyes for corrosion and condition of the hardware.
5. Check horizontal and vertical concrete beams for corrosion and spalling.
6. Check bottom steel beam flanges for fatigue.
7. Check duct banks for:
   - Cracked concrete
   - Collapsed conduit
   - Abandoned cable cut
   - Collapsed header
8. Check walls and ceiling (lids) for:
   - Cracks
   - Exposed or corroded rebar
   - Signs of bowing out
9. Check racks to ensure that:
   - Arms or supports are not corroded
   - Mounting hardware is in good condition
   - Cables are properly fastened with insulators
10. Replace sump grates with fiberglass grates.
11. Clean gravity sumps and check the pumps.
12. Check for presence of anodes and the condition of their connections (if anodes are installed).
13. Check the zinc coating on metal surfaces for signs of degradation.
14. Check for signs of excessive water entering the facility.
15. Check ladders to ensure they are in good condition, if installed.

APPENDIX 18

UNDERGROUND SYSTEM CORROSION

Underground System Corrosion – **NUMM 5.54**

This chapter provides the requirements for the inspection and maintenance of cathodic protection. This should result in early detection of cathodic protective equipment that is either inoperative or deteriorating.

General Description

Corrosion, by definition, is the destruction of a metal by chemical or electro-chemical action with its environment. Electro-chemical corrosion requires four primary factors; i.e., an anode, a cathode, an electrolyte, and an electrical circuit.

Chemical action by acids or alkalis accounts for only a small percentage of the underground corrosion on steel. By far, the greater portion of corrosion is the result of electro-chemical action.

The use of coatings and anodes is also very important in corrosion control.

Equipment/Facilities

- Anodes

Routine Maintenance – **NUMM 6.54**

Galvanic Anode

1. Check the consumption of the anode. Replace the anode when it is approximately 75% consumed as compared to a replacement anode.
2. Inspect the Anode lead for physical damage. Repair the leads if possible, or replace the anode if the leads cannot be repaired.
3. Test the electrical connection of the anode leads for continuity using an ohmmeter. Clean the leads as necessary to provide proper continuity.

Findings

Check the manhole records, if available, to determine when the anode was last replaced. If anodes are being consumed at a rapid rate, it may indicate a need for additional anodes to be installed at this location.

Document replacements of anodes in the MX order in Cascade or on the appropriate inspection form.

APPENDIX 19

INFRARED SURVEY PROGRAM

Infrared Surveys

General Description

The Infrared (IR) Survey Program utilizes technology known as Thermography to identify degraded components. Thermography is a non-destructive test method that remotely senses and measures heat emitted from a component, allowing a temperature comparison between the component, and adjacent or contiguous materials. A significant rise in temperature on a specific component referred to as a “hot spot” or “finding”, indicates that the component is in a degraded condition. The magnitude of the temperature rise is in part proportional to the relative resistance of the device, and is therefore an indicator of the severity of the degradation.

In classifying the severity of a finding, the thermographer must also consider a variety of factors that influence the measured temperature. Two attributes of the material of which the item being scanned is made, emissivity and reflectivity, impact the readings obtained with thermal imaging equipment. Whenever possible, comparisons should be made between components made of like material. The relative load on the circuit must be considered, since higher load will result in a higher temperature rise. In addition to the above, environmental conditions (e.g., direct sunlight, overcast, precipitation, ambient temperature, wind speed, etc.) must also be considered, as they relate to cooling being provided to the component.

The type of component is a factor in determining appropriate corrective actions. Passive, air-cooled components, such as hot-line clamps or splices, can typically tolerate higher temperatures before failure becomes imminent and are generally allowed more latitude in terms of response/repair time. Oil-filled or active devices, such as Capacitors or Vacuum Reclosers, cannot tolerate very high temperatures; corrective action must be taken at relatively low magnitudes of temperature rise for these components.

Facilities and Equipment

An Infrared Survey is performed on all Distribution three-phase overhead backbone circuitry, Distribution substation equipment, and other equipment deemed necessary.

Survey Findings

The findings are classified as “Minor”, “Serious”, and “Emergency” in increasing order of severity. Refer to TD 853 “Infrared Thermographic Inspections” for details

Routine Inspection

1. Perform infrared surveys on all Distribution overhead three-phase backbone and Distribution substation equipment.
2. Analyze the findings of the surveys, prioritize the actions to be taken, and distribute reports in accordance with TD 853 “Infrared Thermographic Inspections”.
3. If deemed necessary, an oil sample can be taken to confirm an abnormally high and unacceptable temperature.
4. Priority and response recommendations provided by the Thermographer are based solely on evaluated equipment condition, and may be adjusted by maintenance management and/or work management personnel as necessary to accommodate scheduling concerns.

Actions Based on Findings:

Infrared surveys may find temperatures that indicate minor to serious conditions that require action ranging from more frequent inspection to immediate repair or replacement of the component

APPENDIX 20

CFM – CYCLIC CIRCUIT FEEDER MANAGEMENT

Guidelines for Cyclic Circuit (Feeder) Management Program

1. Cyclic Circuit Feeder Management ("CFM") Program Basics

1.1 Schedule all CL&P distribution circuits for periodic formal engineering review over a flexible 15-year period.

1.2 Schedule approximately 6.6% of CL&P circuits for a formal engineering review each year.

1.3 Include a CFM review with work on circuits chosen for the TDRP program when possible.

1.4 The Company may adjust the CFM schedule to accommodate new initiatives and to address the evolutionary priorities of the organization. This is primarily a reliability improvement program, and as such, is discretionary.

2. Nature of Engineering Review

2.1 Conduct a complete patrol of the entire circuit to assess plant conditions, tree conditions, and clearances.

2.2 Reliability Performance

- 2.2.1 Review reliability performance of circuit (e.g. SAIDI, SAIFI,).
- 2.2.2 Review customer quality of service complaints (if any).
- 2.2.3 Review outages by cause code relative to system norms.
- 2.2.4 Identify poorly performing line sections or side taps in need of correction and determine the cause of the poor performance.
- 2.2.5 Review design of loop schemes for appropriateness of customer count, independence of sources to zones, and history of improper operation (if any).
- 2.2.6 Assure adequacy of components (conductor, step transformers, cable segments, switching devices, etc.) for normal and contingency loading requirements.

2.3 Protection

- 2.3.1 Check for proper coordination between existing protective devices.
- 2.3.2 Assure protective device and settings are adequate to handle normal and emergency loading.
- 2.3.3 Check the adequacy of isolating devices (numbers/locations).
- 2.3.4 Note locations where side tap cutouts are not installed on junction poles.
- 2.3.5 Note locations of un-fused transformers on circuit backbones.
- 2.3.6 Note location of un-fused side taps.

2.4 Voltage

2.4.1 Review any voltage complaints on circuit.
2.4.2 Evaluate the adequacy of voltage conditions on the circuit for normal and contingency operation (such as for operation of auto-loops).

3. Initiation of Corrective Action

Initiate projects or work requests to correct deficiencies and/or to cost-effectively improve circuit performance. This work includes but is not limited to adding cutouts, isolating devices, and arresters, relocating side-tap cutouts to junction poles where practicable, adding regulators and capacitors, replacing undersized step transformers, primary circuit voltage conversions, reconductoring, improving pole-top construction, and replacing poles.

APPENDIX C

UNITED ILLUMINATING, *MAINTENANCE PLAN FOR TRANSMISSION AND DISTRIBUTION OVERHEAD AND UNDERGROUND LINES*

The United Illuminating Company
Electric Systems Workcenter
801 Bridgeport Avenue
Shelton, CT 06484-4714
203.499.2000

December 30, 2011

Ms. Kimberley J. Santopietro
Executive Secretary
Public Utilities Regulatory Authority
10 Franklin Square
New Britain, CT 06051

RE: Docket No. 11-12-XX
PURA Review of Electric Companies' and Electric Distribution Companies' Plans for Maintenance of Transmission and Distribution Overhead and Underground Lines

Dear Ms. Santopietro:

Attached is one (1) copy of The United Illuminating Company's ("UI") Maintenance Plan for Transmission and Distribution Overhead and Underground Lines ("Plan") for 2012. This Plan is being submitted pursuant to Section 16-32g of the Connecticut General Statutes.

Should you have any questions or comments regarding UI's Plan, kindly contact me at (203) 926-4515.

Very truly yours,

John Mitchell

John Mitchell
Manager, System Maintenance

Attachment

THE UNITED ILLUMINATING COMPANY

Docket No. 11-12-XX

Maintenance Plan for Transmission and Distribution Overhead and Underground Lines

Revised: December 30, 2011

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1. Executive Overview

Goals and Objectives

Proper maintenance of The United Illuminating Company's (UI or Company) transmission and distribution facilities has played a major role in achieving high reliability, public safety, and customer satisfaction, and is a key element of UI corporate strategy. The Company continues active development and implementation of maintenance processes to improve customer satisfaction. UI's electric system maintenance practices focus on cost effectiveness while maintaining high levels of service to our customers.

The United Illuminating Company's Maintenance Program Goals are:

- To work safely everyday
- To maintain reliability performance at 1998 levels.
- To achieve these goals at the minimum cost to our customers.

The United Illuminating Company's Maintenance Plan addresses assets in six subsections:

- Overhead Distribution System
- Underground Distribution System
- Overhead Transmission System
- Underground Transmission System
- Substations
- Tree Trimming

Reliability Centered Maintenance

Since 1997, UI has employed a Reliability Centered Maintenance (RCM) program approach to system maintenance. In general, this approach applies equipment inspection, diagnostic testing, analysis of historical data, and other techniques, to determine the nature and timing of preventive maintenance actions. Hence, in RCM, traditional "time-based" maintenance is supplemented or replaced by predictive or "condition-based" maintenance. The specific strategy for the UI electric system is to move toward condition-based maintenance while continuing appropriate traditional time-based maintenance activities.

At UI, the Reliability Centered Maintenance program is a continually evolving process that strives to understand an asset's potential for failure by focusing resources on preservation of system function, as opposed to traditional maintenance to preserve individual equipment operation. This approach improves cost effectiveness by reducing unwarranted corrective-reactive maintenance.

2. Introduction

Maintenance is a dynamic process that combines analysis of historical data, carefully developed procedures that use proven predictive maintenance techniques, and cost effective time-based maintenance tasks. The judgment of experienced operating and engineering personnel is continually sought out and incorporated into the Reliability Centered Maintenance Program. UI has developed a work routine that strives to make preventive action a daily responsibility. Electric System Operations personnel traveling in the system are encouraged to report any

abnormal conditions to the operating department in a proactive manner. The goal of UI's Maintenance Program is to maximize safety and reliability of the distribution and transmission systems in a cost effective manner.

3. System Description

The United Illuminating Company is located in the southwest area of Connecticut on the north shore of Long Island Sound. UI serves seventeen cities and towns surrounding the principal cities of New Haven and Bridgeport. The service territory is approximately 335 square miles with a population of approximately 761,000 people[1]. System peak load for recent years is shown in the following table:

Table 1: System Peak Load, 2006 to 2011

	2006	2007	2008	2009	2010	2011
Peak Load (MW)	1,456	1,298	1,301	1,253	1,365	1,401
Date of Peak Load	8/03/06	8/08/07	6/10/08	8/21/09	7/06/10	7/22/11

The map provided in Attachment 1 shows the UI service territory and the municipalities supplied within the service area.

To serve its customers, the UI Company owns, operates and maintains the following:

- 27 bulk transmission substations with a capacity of 1,883 MVA.
- 4 transmission switching stations.
- 17 distribution substations with a capacity of 87 MVA.
- Approximately 3,293 pole line miles of overhead distribution lines (1ϕ and 3ϕ).
    - This includes primary, secondary an aerial cable and excludes service conductors.
- 132 miles of underground conduit banks.
- 648 miles of underground primary cables (1ϕ and 3ϕ) consisting of direct-buried as well as underground duct and splicing chamber construction.
- Approximately 81% of the distribution system is fed at 13,800 volts, with the remaining load supplied at 4,160 or 2,400 volts.
- Two underground network systems in the downtown areas of New Haven and Bridgeport utilize interconnected secondary cables (120/208Y volt) designed primarily for high-density urban areas.
- Some of the larger downtown loads are supplied by 277/480Y volt systems that are not interconnected and are called "spot networks".
- The UI transmission system consists of 6.2 circuit miles of overhead 345,000-volt line, 94.85 circuit miles of overhead 115,000-volt line, 17.25 circuit miles of underground 115,000-volt line, and 11.2 circuit miles of underground 345,000-volt line.

A summary of the conductor types used in the UI system is found in Table 4 at the end of this section. Note that this table contains mileage of conductor types categorized by voltage level.

[1] 2010 Annual Population Estimates Data for Connecticut's Towns and Counties as reported on the State of Connecticut Department of Public Health website http://www.ct.gov/dph/cwp/view.asp?a=3132&q=388156

The data for this table was obtained by using the Company's Geographical Information System (GIS).

The Company's service area is composed of urban, suburban, and to a lesser extent rural areas. The urban areas are located in the downtown centers of Bridgeport and New Haven, as well as in the smaller cities and towns, including Fairfield, Shelton, Derby, Ansonia, Stratford, Milford, West Haven, Hamden, and East Haven. The remaining service area is mostly suburban.

Most of UI's commercial customers occupy land adjoining the major inter-city highways, such as I-95 and US #1 from Fairfield to East Haven, Route #8 from Bridgeport to Ansonia, I-91 and US #5 from New Haven to North Haven and Routes #10 and #15 from New Haven to Hamden. Most of the large industrial customers are situated along the Railroad Rights-of-Way on the shoreline, and in the Housatonic and Quinnipiac River Valleys.

Almost all of the non-commercial areas are suburban residential tracts. The only true rural area left in the service territory is in Easton, except for scattered farms in North Haven, North Branford, and Orange, as well as state and local parklands. Much of the territory, including the rural, suburban, and residential area just outside the urban centers, is heavily treed.

Service reliability, without question, is of vital importance to the viability of the Company as well as the local economy and remains extremely important to the Company and all of our customers. In particular, the very existence of our commercial and industrial customers, which comprise approximately 59% of our sales base, depends on UI's ability to provide reliable service.

The following table summarizes the MWHR sales mix for the period 2005-2011:

Table 2: MWHR sales mix for the period 2005-2011

Customer Class	2005	2006	2007	2008	2009	2010	2011 Current Forecast
Residential	40.3%	39.9%	39.7%	39.7%	39.8%	40.3%	40.4%
Commercial	44.3%	45.2%	46.3%	47.6%	48.6%	48.1%	48.1%
Industrial	14.8%	14.2%	13.3%	12.1%	10.8%	10.8%	10.7%
Street Lighting	0.7%	0.7%	0.7%	0.7%	0.8%	0.8%	0.8%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.1%**

The following table summarizes the breakdown of customers by class for the period 2005-2011:

Table 3: Breakdown of customers by class for the period 2005-2011

Customer Class	2005	2006	2007	2008	2009	2010	2011 Current Forecast
Residential	289,866	291,164	292,535	293,009	292,836	292,670	290,958
Commercial	29,003	29,081	29,941	30,392	30,432	30,493	30,265
Industrial	1,326	1,226	1,151	1,133	1,142	1,091	1,035
Street Lighting	1,250	1,230	1,222	1,207	1,344	1,202	1,166
Total	**321,445**	**322,701**	**324,849**	**325,741**	**325,754**	**325,456**	**323,425**

The following table summarizes transmission and distribution system miles by construction type and voltage level:

Table 4: Transmission and Distribution System Miles by Construction Type and Voltage Level

Construction Type	Circuit Miles		
	15kV or less	115kV	345kV & Higher
Tree Wire	2367	0	0
Non-Tree Wire	297	95	6.2
Aerial Cable	209	0	0
Self-Supporting Cable	2	0	0
Underground Cable*	648	17	11.2
Totals	**3523**	**112**	**17.4**

Definitions:

Tree Wire:
All primary wire used in open wire construction that is covered with a 10/64 polyethylene coating.

Non-Tree Wire:
All primary wire used in open wire construction that either has no insulation (bare) or is covered with a material having little or no insulation value.

Aerial Cable:
Shielded primary cable suspended from a messenger attached to poles.

Self Supporting Cable:
Unshielded insulated primary wire triplexed around a messenger attached to poles.

****Underground Cable***
Distribution: Includes both shielded primary cable in a splicing chamber and duct system, and direct buried cable.
Transmission: Includes pipe type, gas insulated, fluid filled and solid dielectric in a splicing chamber and duct system.
*Secondaries and services excluded

4. Line Clearance / Vegetation Management

The United Illuminating Company remains committed to providing high levels of reliability, while simultaneously ensuring customer safety and satisfaction, and controlling cost. In 2011, the Company completed the fourteenth year of the Performance-Based tree trimming program. All customer requests and concerns about tree conditions are investigated and trimming is performed as required to eliminate those concerns whether from an electric safety or reliability point of view.

The overhead distribution line clearance program consists of a split four-year and eight-year cycle for planned tree trimming. The three-phase portion of the system is trimmed on a four-year cycle, while the single-phase portion of the system is trimmed on an eight-year cycle or where performance triggers more frequent trimming. Any single-phase portion of the system that experiences two or more tree related outages in a 36-month period is, at a minimum, trimmed to minimize the potential for future outages. Other system modifications, such as reconductoring bare wire with tree wire, may also be performed to help minimize the potential for future tree related outages. In addition, trimming is completed at new construction sites as needed. Other system modifications, such as reconductoring bare wire with tree wire, may also be performed to help minimize the potential for future tree related outages. In addition, trimming is completed at new construction sites as needed.

Beyond the Line Clearance planned circuit miles program, the Company implements the following vegetation management programs to maintain or enhance the reliability of the electric distribution system:

- RCM Single Phase Line Clearance: RCM Single Phase Line Clearance is not part of the program work but rather performance based trimming initiated following occurrences of two tree related outages on a circuit during the prior 36 months. Trimming is performed based on the trim specifications on the entire side tap back to the first interrupting device. This is intended to minimize any tree related outages from occurring perpetually.

- Hazardous Trees: The Hazardous Tree program requires the complete removal to ground of all identified trees. Hazard trees are identified in several ways including; UI vegetation management resources, contractor permissions personnel, tree trim crews, town tree wardens and customers. The hazard tree removal program is designed to remove trees identified as dead, dying, diseased or structurally defective and located outside of the normal trim area, but pose a potential hazard to UI facilities. The process involves identification of hazardous trees through the circuit trimming program, reliability engineer, and Line Clearance Arborist and Technicians then communication with customers, CDOT and/or municipalities to inform them of the hazard and obtain permission to remove.

- Vine Management: Vine Management is the removal of various vines from poles and guy wires including the ground cut, removal, chip and disposal of debris.

- Distribution Rights-Of Way Line Clearance: Rights-of-Way Line Clearance is the removal of overgrowth on the distribution right-of ways. Typically, such work is identified and generated through ROW inspections and maintenance trim cycles.

Transmission lines are trimmed on a four year cycle (approx. 25% per year). The cycle based trimming is supplemented with inspection of 100% of the overhead transmission lines. UI's Transmission Vegetation Management Program (TVMP) complies with the North American Electric Reliability Corporation (NERC) FAC-003-1 Standard, covering all the transmission lines operated at 200kV and above, and specific lower voltage lines designated by the Northeast Power Coordinating Council (NPCC) as being critical to the reliability of the electric system in the region. Transmission line ROW are inspected annually by foot patrol for the purpose of identifying vegetation conditions that could encroach the vegetation to conductor clearance requirements, impact electric service reliability or create a hazard to the public. In 2010 UI implemented an improvement to the inspection process which utilized the use of Light Detection and Ranging (LiDAR) imaging and processing capabilities. Any vegetation conditions which might immediately affect operation or maintenance of the lines are addressed immediately. All data from the inspections is captured electronically and then imported into a tracking database. Reports are generated from this database to assist in developing work schedules and tracking work to completion. The UI Line Clearance Arborist re-inspects all reported vegetation items, develops the maintenance trimming schedule, prioritizes work and coordinates with the railroad entities. Field audits are completed to ensure the work performed meets the TVMP requirements.

UI continues to work with local tree wardens, as well as civic and professional groups, to help educate customers about the proper selection and care of trees that may be planted near UI's electric facilities. In addition, safety brochures are distributed annually through bill inserts, and other events are held to educate the public on the dangers associated with energized wires and the importance of having qualified tree contractors or UI line clearance crews remove hazardous tree growth. We believe that we can continue to provide safe, reliable service in a cost-effective manner by working together with our customers in matters of line clearance and vegetation management.

UI's Line Clearance and Vegetation Management Specifications are appended to this document as an Attachment 2.

5. Maintenance Practices

The primary goal of Reliability Centered Maintenance (RCM) is to keep equipment operating properly while minimizing total maintenance costs. RCM uses proven predictive maintenance techniques to schedule cost effective maintenance only when needed (based on experience, inspection and testing results, manufacturers' data, etc.) to prevent critical failures.

It should be understood that the term maintenance, as used at UI, includes both inspection and maintenance activities. UI crews perform construction, inspection and maintenance activities, thereby developing a balanced, well-rounded work force and minimizing costs.

UI employees perform the majority of maintenance work on the distribution system, with the exception of tree trimming, pole inspection and treatment, and street light repair/replace, which are done by outside contract crews. During peak constructions periods, outside contract crews may augment UI crews on construction projects. Outside contract crews are also used on UI's transmission system for both major construction and maintenance functions.

Maintenance practices in the following sections are organized as noted below:

- Construction / Maintenance Work Force Organization
- Equipment Maintenance by Area
- Overhead Distribution System
- Underground Distribution System
- Overhead Transmission System
- Underground Transmission System
- Substations
- Tree Trimming (Attachment 2)
- General

5.1. Construction and Maintenance Workforce Organization

The following is a staffing summary by section and grade of UI's construction and maintenance departments (as of November 21, 2011):

Table 5: Construction and Maintenance Work Force Organization

Department	Position	Number
System Maintenance	Manager, System Maintenance	1
	Maintenance Engineer	7
	Civil/Structural Engineer	1
	Line Clearance Arborist & Technician	3
	Analyst & Tech Support Specialist	1
	Total System Maintenance	13
Power Delivery (PD)	General Manager - Construction Operations	1
	Manager – Power Delivery	2
	Supervisor - Power Delivery	13
	Scheduler - Power Delivery	2
	Line Worker 1st Class	30
	Line Worker 2nd & 3rd Class (Apprentice)	29
	Line Worker 5th Class (Helper)	0
	Line Trouble Shooter	8
	Line Group Leader	33
	Cable Splicer 1st, 2nd & 3rd Class	14
	Underground Working Leader	2
	Underground Inspector	3
	Supervisor - UG Construction	2
	UG PD Equipment Specialist & Helper	10
	Administrative Clerks - PD	3
	Total Power Delivery (PD)	152
Transmission & Substation (T&S)	Manager - T&S	1
	Supervisor - T&S	12
	Scheduler - T&S	1
	Substation Utility Worker	2
	Substation Maintenance Worker	1
	Substation Electrician Const. & Maint. Worker	21
	Substation Electrician 1st Class	5
	Substation Electrician 2nd Class	0
	Substation Electrician 3rd Class	5
	Substation Electrician Specialist	12
	Test Engineer	2
	Test Technician	16
	Glove Lab Technician	2
	Administrative Clerks - T&S	1
	Total Transmission & Substation (T&S)	81
Total Construction & Maintenance Work Force		246

5.2. Maintenance of Assets and Systems by Area

The Company uses a software application called Maximo® to manage the maintenance of equipment. Maximo® serves many functions, as it contains historical asset record data along with an asset registry, and also generates work orders associated with preventive and corrective maintenance plans. Several other databases are utilized in conjunction with Maximo® for implementing the RCM plan. These databases are linked where possible.

UI visually inspects its overhead equipment in accordance with defined RCM programs and whenever work is being performed on the system. The major components of UI's Overhead Distribution System are identified below. Details of maintenance and inspections are noted in each asset category.

It should be noted that, in the course of any inspection and maintenance process described in this report, all hazards, damage, and other abnormal conditions affecting equipment on the UI system, are immediately reported to appropriate supervision, who then analyze the situation and coordinate corrective actions. Also, additional attention is given to any equipment as deemed appropriate by Electric System Maintenance.

The following tables list major components of the overhead and underground distribution and transmission systems

5.2.1. Table 6: Maintenance Practices, Overhead Distribution System

Category	Sub Category	Frequency	Task Description	Notes
General		During pole inspection and when working on pole	Visual Inspection	Includes poles, ancillary equipment, wire and cable, hardware, fault indicators, lightning arresters, switches and other equipment associated with an installation.
Poles and Ancillary Equipment	Poles, <10 years old	6 years and when working on pole	Above ground line visual inspection	
	Poles, =>10 years old		Visual inspection above and below the ground line. Internally treated for decay below the ground line if necessary.	Below ground line treatment involves excavating to a depth of 18 inches and treating the pole below grade
Overhead Wire	Wire, All	During pole inspection and when working on pole	Visual Inspection	Problems reported in the Circuit Interruption Reporting System are reviewed for further investigation and corrective action.
	Wire, 3 phase lines	Annually	Infrared Inspection	
	Wire, Single phase lines	Performance Based	Infrared Inspection	

Maintenance Practices, Overhead Distribution System
(continued)

Category	Sub Category	Frequency	Task Description	Notes
Aerial Cable	All	Upon Installation	Dielectric test of insulation integrity	
	Paper Insulated Lead Covered (PILC), 13.8kV Circuits	As above for Aerial Cable	In addition to a visual inspection when working on a pole, this type of cable is replaced on a scheduled, programmatic basis.	By the end of 2012, all PILC will have been removed or replaced
Insulators, Lightning Arresters, Hotline Clamps, Stirrups and Splices	3 phase lines	Annually	Infrared Inspection	
Switches, Disconnects and Fused Cutouts	3 phase lines	Annually	Infrared Inspection	
	Single phase lines	Performance Based	Infrared Inspection	
Overhead Fault Indicators	All	10 years	Replace	Electronic Fault Indicators have replaced mechanical Fault Indicators. The replacement cycle has been increased from 5 to 10 years.
Pole Mounted Transformers	Utilization Transformers	See Notes		Transformers whose PCB content is unknown, are loaded at or near nameplate ratings and those found in poor condition have been identified and are included for replacement in the Company's 10 Year Plan
	Step-down Transformers	Monitored as Required	Electronic monitoring devices monitor phase loading	
Pole Mounted Capacitor Banks	Radio Controlled	Annually	Signal tested through SCADA	
		2 Years	Visual Inspection	
	Fixed	Annually	Operationally tested and inspected. Operations counter recorded, voltage and settings confirmed and recorded in MAXIMO for review.	
	All	Annually	Infrared Inspection	Action taken based on current RCM criteria and data review.

Maintenance Practices, Overhead Distribution System
(continued)

Category	Sub Category	Frequency	Task Description	Notes
Pole Mounted Voltage Regulators	All	Annually	Operationally tested and inspected. Operations counter recorded, voltage and settings confirmed and recorded in MAXIMO for review.	Action taken based on current RCM criteria and data review.
		Annually	Infrared Inspection	
Pole Mounted Reclosers	All	Quarterly	Operations counter recorded, batteries tested and settings confirmed and recorded in MAXIMO for review.	
		Annually	Infrared Inspection	
	Oil Insulated	7 years	Internal and Operational testing	Based on current RCM criteria
Street Lights	All	Failure	Repair or Replace as required	Failures are reported by customers, police and UI personnel.
		7 years	Relamp, replace photocell and perform general maintenance	

5.2.2. Table 7: Maintenance Practices, Underground Distribution System

Category	Sub Category	Frequency	Task Description	Notes
General		During inspection and when working at a specific location	Visual Inspection	Includes electrical components, structural elements, cable, hardware and other equipment associated with an installation.
Splicing Chambers and Secondary Network Vaults		Regular inspection frequency being evaluated	Visual inspection of the electrical and physical condition of the location and equipment contained therein.	Equipment includes grounding, cable racks, cable supports, covers, roofs, frames and other structural elements.
Network Transformers	Network Protectors	Annually	Visual Inspection including protector status, nitrogen blanket pressure and overall condition assessment	
	Network Transformers and Switches	Annual	Visual Inspection including oil level inspection and recording and overall condition assessment	

Table 7: Maintenance Practices, Underground Distribution System
(continued)

Category	Sub Category	Frequency	Task Description	Notes
Wire and Cable	All Primary Cable	When any work to the electrical insulation of a cable is performed	Dielectric Testing	
	Primary Cable, Paper Insulated Lead Covered (PILC), 13.8kV Circuits	As above for Primary Cable	In addition to a visual inspection when working on a pole, this type of cable is replaced on a scheduled, programmatic basis.	Replacement priority based on performance and potential failure impact on system reliability.
	Solid Dielectric Primary Cable	As above for Primary Cable		Replacement is performance based
	Distribution Cable	During inspection of the splicing chamber or vault	Visual inspection	
2400V PKL Switches		None	Maintenance is performed on an as-needed basis	PKL switches are scheduled to be eliminated by the end of 2012
Padmounted Transformers and Junction Enclosures		5 years	Visual inspection for safety hazards, security, electrical integrity and damage	
Padmounted Switches		Twice annually: in the Spring and again in the Fall	Visual inspection for safety hazards, security, electrical integrity and damage	
Customer-Owned Facilities	Transclosures	Program	Installation of a second physical barrier for NESC compliance	Completion of all locations expected by the end of 2015
		2 years	Visual inspection for safety hazards, security, electrical integrity and damage	Abnormal conditions are brought to the customer's attention for remediation and work is scheduled appropriately
	Transformer Vaults	3 years		
	Transformer Cages	Annually		
		On-going program		These installations are being replaced based on prioritization established from the inspection program, when the customer's service is abandoned, at the customer's request or when system upgrades are required.

5.2.3. Table 8: Maintenance Practices, Overhead Transmission System

Category	Sub Category	Frequency	Task Description	Notes
Towers	All	Annual	Inspected by outside contractors. Inspection includes items such as ground conductor integrity, paint condition, installation of proper signage, etc.	Climbing inspections are performed as required.
	Wood	5 Years	Ground level inspection of the structure.	
	Cathodic Protected Steel Structures	Annual	Test and review results for proper operation of the passive cathodic protection system	
Connectors, Conductors, Terminations and Insulators	All	Annual	Visual inspection	
		2 Years	Visual inspection by air (helicopter) which includes an infrared thermographic inspection	
		Condition-based	Corona Imaging	
	Substation Components	Semi-annual	Visual and thermographic inspection	
Foundations	All	Annual	Visual inspection of condition	
	Cathodic Protected Caissons	Annual	Test and review results for proper operation of the passive cathodic protection system	
Right-of-Ways (ROW)	Vegetation	Annual	Visual Inspection	
	Light Detection and Ranging Inspection (LiDAR)	2 years	Identify and measure vegetation clearances to conductors on and along UI ROW	

5.2.4. Table 9: Maintenance Practices, Underground Transmission System

Category	Sub Category	Frequency	Task Description	Notes
Termination Support Structures		Annual	Visual inspection	Additional inspections are performed through monthly substation patrol safety and security inspections.
Cable and Cable Terminations	All Components	When working in a specific location	Visual inspection of accessible portions	Additional inspections of accessible equipment are performed during various substation inspections.
	Terminations	Semi-annual	Visual and Thermographic Inspection	
	High Pressure Fluid Filled (HPFF) Cable and Terminations	3 Years	Fluid is tested for dielectric quality and dissolved gasses.	
	Low Pressure Fluid Filled (LPFF) Cable and Terminations	Bi-annual		
	Solid Dielectric Cable	5 Years	Visual inspection	
Splicing Chambers	High Pressure Fluid Filled (HPFF) and Solid Dielectric Cable Lines	5 Years, during cable inspection or when working in a specific location	Condition assessments are done when inspections indicate further action, which includes an accelerated systematic evaluation of the present condition and future maintenance/replacement requirements for the underground infrastructure.	
	Low Pressure Fluid Filled (LPFF) Lines	Annually		
	345kV Solid Dielectric Lines in ConnDOT Right-of-Ways	In accordance with the requirements of the Conn DOT Bridge Inspection Manual		
Cable Pressurization and Pumping Systems	All	Monthly	Visual inspection and pressure readings are recorded and reviewed	
	Dielectric Fluid	3 years	These are the sample points for the HPFF Cable noted above	
	High and Low Pressure Setpoints	2 Years	Tested and Calibrated	
Active Cathodic Protection Systems		Annually	Output is verified at intermediate test points and at the underground cable extremities in the substation.	
		Monthly	Visual condition assessment. Voltage and current values are recorded and reviewed.	

5.2.5. Table 10: Maintenance Practices, Substations

Category	Sub Category	Frequency	Task Description	Notes
Bulk Substation current carrying equipment	Outside equipment and equipment accessible within the building	Bi-annual	Thermographic Inspection	Includes exterior and interior components. Action taken based on current RCM criteria and data review.
Distribution Substation current carrying equipment		Annually		
Stationary Battery Systems	All Installations	Monthly	Visual inspection of overall condition including electrolyte levels (if applicable), voltage and current levels and physical condition of components	In accordance to industry accepted standards and applicable NERC / NPCC requirements
		Annually	Conductance and voltage testing and trending	
Transformers and Reactors	All	Annually	Oil quality and Dissolved Gas Analysis (DGA) is performed and reviewed	
		Monthly	Visual Inspection	
	Bulk and Transmission Substations	3 years	Power factor and excitation testing for the integrity of insulating materials, windings, bushing insulation. Load tap changer operation. Operational testing of external components is performed to ensure the proper operation of alarms and monitoring equipment.	
	Distribution Substations	Condition based		Distribution substation transformers are tested only if infrared inspections, oil testing or a visual inspection detect an issue
Transmission Class Circuit Breakers	Bulk Oil (OCB)	2 years	Timing and motion, power factor testing and oil quality analysis	Internal inspections and overhauls are condition based but typically will not exceed the manufacturer's recommendation
	Gas Insulated (SF_6)	Per manufacturer's recommendation, condition assessment or Best Industry Practice	Timing and motion and gas moisture analysis	
Distribution Class Circuit Breakers	Oil (OCB)	6 years	Per manufacturer's recommendation or based on Best Industry Practice	
	Air Magnetic (ACB)	6 years		
	Vacuum Interrupters (VCB)	10 years		

Table 10: Maintenance Practices, Substations
(continued)

Category	Sub Category	Frequency	Task Description	Notes
Protective Systems	Protective Systems and Substations as defined by North American Electric Reliability Council (NERC) Standards and Northeast Power Coordinating Council (NPCC)	As specified inn NERC Standards	NERC Standards include: • PRC-005-1: "Transmission and Generation Protection System Maintenance and Testing" • PRC-008-1: "Implementation and Documentation of UFLS Equipment Maintenance Program" • PRC-011-0: "UVLS System Maintenance and Testing"	Systems include protective relaying, batteries and battery chargers, circuit breakers, transformers and protective relaying telecommunications
		As specified in NPCC Directories	Directory #3 "Maintenance Criteria for Bulk Power System Protection."	
	Special Protection Systems as defined by North American Electric Reliability Council (NERC) Standards and Northeast Power Coordinating Council (NPCC)	NPCC	As described in NPCC Directory #7 "Special Protection Systems".	These protection systems are designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted elements.
		NERC	As described in • PRC-012-0: "Special Protection System Review Procedure" and • PRC-017-0: "Special Protection System Maintenance and Testing"	
	Non-Bulk (Distribution) Stations	4 years	Test and adjust protective relaying as required	
Buildings and Structures	Security and Safety	Monthly and whenever a station is visited	Includes testing of security systems, security inspections of interior and exterior facitlites, fire-extinguisher inspections, first-aid kit inspections and similar tasks	
	General	Monthly	Facilities are cleaned, operation counts are taken and minor maintenance activities are performed	
	Roof Systems	Annually	Gutters and downspouts are inspected and cleaned	
		3 years	Substation roofs are inspected	

5.2.6. Tree Trimming

Tree trimming practices are described in Section 4 and Attachment 2.

5.2.7. General

Employee awareness of system conditions constitutes a vital source of information for UI to address maintenance requirements. Employees, as they travel to their work locations throughout UI's territory, are encouraged to be observant and report any abnormal conditions to Electric System Operations or Electric System Maintenance so that appropriate action can be taken. This information, along with reports via telephone or written communication from our customers or others regarding abnormal system conditions, is captured in the computer-based Customer Request System. It is then forwarded to Electric System Operations and Electric System Maintenance for investigation and resolution, as required. The trouble conditions and subsequent resolution is captured in the customer call system, SAP.

6. Latest Updated Maintenance Practices

6.1. Summary of Updated Maintenance Practices

Inspection and maintenance is currently being performed as described in earlier sections. The following summarizes the differences between this current Maintenance Plan and the plan dated December 22, 2010.

The Company continues to operate and maintain its system generally using the same practices that were in place as of the Maintenance Plan dated December 22, 2010. The maintenance practices in use are defined in our Reliability Centered Maintenance program, which has been in effect for approximately thirteen years. The Company continuously looks for opportunities to improve both operational performance and cost efficiency. The major changes which have occurred since 2010 are in the areas of Secondary Network Vaults, Splicing Chambers, Transmission Line Inspections and Bulk Substation Security Systems.

Any Directives or Recommendations from PURA Docket No. 11-09-09, "Investigation of the Service Response and Communications of the Connecticut Light and Power Company and The United Illuminating Company and Report on the Operations of the Telecommunications, Natural Gas and Water Public Service Companies Following Power Outages Resulting from Hurricane Irene" and the Governor's Two Storm Panel (*Formerly known as the "S.T.O.R.M. Irene Panel"*) will be reviewed and, if appropriate, included in future maintenance plans.

6.1.1. Table 11: Overhead Distribution

Object	Change	Rationale for Change
Pole Inspection	In 2011 approximately 20,574 UI custodial poles were inspected. This completes the six year inspection cycle. Since 2004, 3700 reject poles have been identified. All but 18 have been remediated or the ownership records have been reconciled	The inspection cycle is currently under review and the future cycle will be based on Industry Best Practice.
Pole Replacements	For the period of 2004-2011, the Pole Inspection program reported 3700 reject poles. For the same period a total of 3446 of the reject poles have been replaced thru the Pole Replacement Program. Beyond the Pole Replacement Program, other poles are replaced thru capital construction projects, customer projects and to a lesser degree damaged poles.	Deteriorated poles are identified thru the pole inspection program at a historical reject rate of approximately 4% annually. Replacement of the deteriorated poles meets UI's goals for safety, customer service and to maintain reliability of the electric system. The intent of the program is to complete replacement of the deteriorated poles the following year of the inspection, with the exception of priority rejects, which are replaced shortly after they are identified.
Pole mounted Reclosers	Change from 4 times per year to 3 times per year In the months of March, July and November	Other programs such as the Recloser Battery Replacement Program result in the need for fewer inspections. This inspection interval change is being done on a trial basis

6.1.2. Table 12: Underground Distribution System Changes

Object	Change	Rationale for Change
Secondary Network Vaults	A safety program was introduced this year which started with a verification of the proper operation of all network protectors. This program would also remediate any equipment issues identified. All other network equipment and structure improvement and remediation programs were put on hold, except in response to emergency or safety-related issues.	The company retained the services of a materials and forensic expert to perform a comprehensive investigation of a recent network vault equipment failure. The findings of the investigation resulted in development of a program to correct issues which the investigation determined contributed to the cause and aggravation of the failure.
Splicing Chamber Inspections	Regular inspection frequency being evaluated	Evaluating a 5 year inspection program

6.1.3. Table 13: Overhead Transmission System Changes

Object	Change	Rationale for Change
Transmission Line Inspection	The Company plans to continue to perform climbing inspections as part of it Transmission Maintenance program and is currently investigating different technologies that would allow for the condition assessment of transmission conductor wire by measuring the remaining cross-sectional area of the steel core wires in conductors. The company plans to perform this type of condition assessment in 2012.	In 2011, the Company began to perform climbing inspections of transmission towers and plans to continue to do so in the years to come. These inspections will allow for a closer and more efficient condition assessment of the structures. The need for this type of inspection was prompted by the failure of one of the conductor attachment plates early in the year. As a result of the inspection findings, the Company replaced all attachment plate hardware and insulator strings to 29 lattice structures.

Table 13: Overhead Transmission System Changes
(continued)

Object	Change	Rationale for Change
Transmission Vegetation Management Program (TVMP)	In 2011, the following enhancements were incorporated into the TVMP: The inspection process utilized LiDAR (Light detection and ranging) imaging and processing capabilities to identify vegetation conditions in and along the ROW. The LiDAR data processing identified vegetation conditions at the time of the survey and vegetation conditions based on modeled data for maximum sag and sway conditions. Conducted ground inspections to validate the processed data and work orders were prepared to remediate the conditions. The priority grow-in and hazard tree conditions were trimmed or removed. The TVMP document was reviewed and revised. Integrated Vegetation Management methodologies were researched.	In 2010, the Company performed a comprehensive review of its TVMP. This review has changed our interpretation of the requirements and we recognize that changes need to be made to ensure the TVMP meets the requirements of NERC FAC-003-1. We plan to implement the recommendations in phases over the next 3 years. UI has retained the services of CN Utility Consulting to assist in the implementation; their expertise and collective knowledge in utility vegetation management is extensive and supports our plan. The following are recommended areas for improvement: 1. Monitor FERC/NERC and other industry activities to understand impending changes 2. Review and update the TVMP documentation 3. TVMP needs to be reviewed and updated annually to ensure that UI's TVMP is aligned with requirements and expectations 4. Incorporate improvements to the annual cycle maintenance and inspection process. 5. Investigate needs, benefits, costs of reclaiming of UI's Transmission ROW 6. Investigation into Integrated Vegetation Management (IVM) methodologies to replace/supplant the current cycle and inspection process

6.1.4. Table 14: Underground Transmission System Changes

Object	Change	Rationale for Change
345kV Cable and Splice Chamber Inspections	All 345kV Cable splices and splicing chambers were inspected this year by a structural engineer and factory representatives. Findings determined that a follow-up inspection will be scheduled for 2012. The results of the follow-up inspection will determine the future maintenance/inspection cycle, but it will not exceed the frequency required by CDOT.	
115kV Cable and Splice Chamber Inspections	All 115kV splicing chambers were inspected this year by a structural engineer. These lines continue to be on a 5 year cycle with the exception of the low pressure fluid filled lines, which continue to be on an annual cycle.	

6.1.5. Table 15: Substation Changes

Object	Change	Rationale for Change
Stationary Battery Systems	In 2011, online battery monitoring systems were added to several bulk substations. Also, the last lead-antimony battery system was removed from the system allowing the elimination of regular specific gravity testing.	Battery Monitors allow real-time monitoring of these critical systems. Removal of Specific Gravity testing results in improved worker safety and increased productivity. Additionally, IEEE Standard 450 no longer recommends this test for batteries other than lead-antimony
Transmission Class Gas Circuit Breakers (GCBs)	In 2011 the standard for the purchase of gas circuit breakers (GCBs) was modified to include breaker monitoring equipment. Future improvements will include SF6 gas monitoring to minimize emissions and the possible involvement in an Electric Power Research Institute (EPRI) study to determine proper lubrication materials and techniques.	Breaker Condition Monitors will accelerate the move towards condition-based maintenance as valuable information will be available without the need to disassemble a GCB. Proper lubrication techniques will help maintain reliability, system integrity and safety.
Substation Condition Assessments	In 2007, the Company began performing comprehensive condition assessments of 115kV substations to determine the future viability of the facilities. The assessment incorporated present structural conditions, substation design, equipment condition and obsolescence of the installed equipment and anticipated aging for an additional 10 years or more. The assessments of the following (4) substations have been completed in 2011: • Ansonia • Devon Tie • Mill River • RESCO	The Company performed a "Ten-Year Transmission and Substation Infrastructure Planning Study 2010-2019" (2010 TYP). The 2010 TYP identified the projects required to assure continued reliable service to our customers in the next ten years and evaluated existing infrastructure reliability in terms of: 1. Sufficient system capacity to serve customer load based on future System Peak Load forecasts 2. Considerations related to aging infrastructure 3. Meeting regional and national transmission reliability standards The Company employs a materials and forensic experts to perform the condition assessments. The assessments are performed on substations which were identified in the 2010 TYP to support the scope and need for the individual projects. The review incorporates present structural conditions, substation design, equipment condition and obsolescence of the installed equipment, maintenance records, and interviews with UI personnel to gain insight into operational histories of key equipment and anticipated aging for an additional 10 years or more. The assessments identified deficiencies and support the business case for remediation projects. Additionally, recommendations are documented of each asset where intervention might prevent a failure, reduce risk, or extend service life.

Table 15: Substation Changes
(continued)

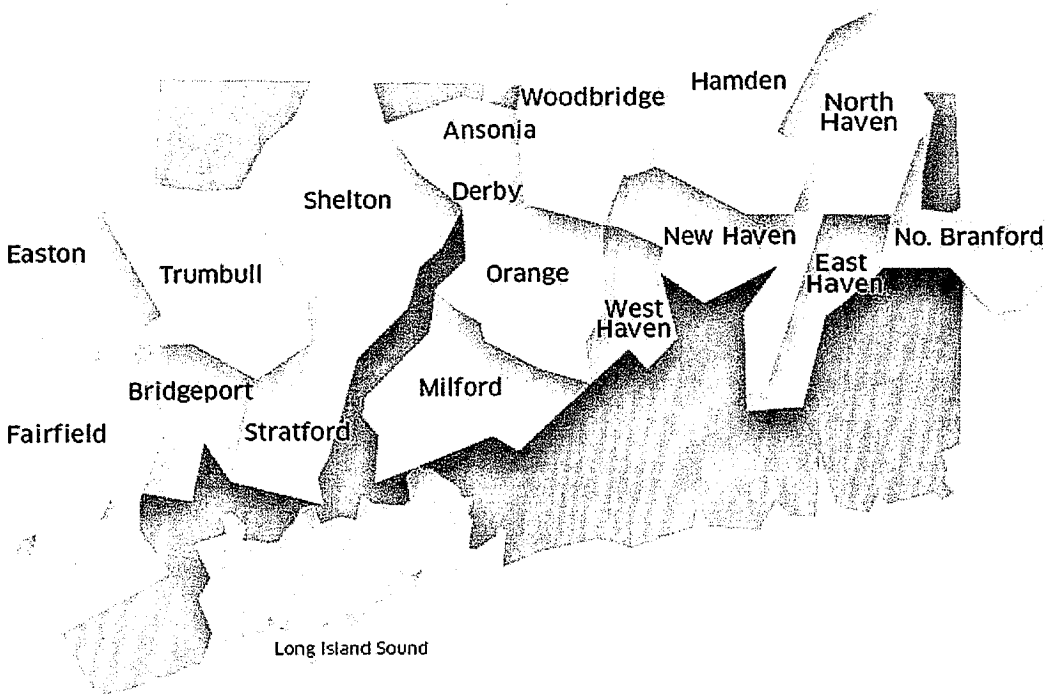
Object	Change	Rationale for Change
Bulk Substation Security Systems	Key Card Readers, electronic locks and motion detectors have been added at Bulk Substations for additional access control.	The security system upgrade was installed to comply with NERC standard CIP-006
	Annual maintenance and testing of the additional security components was added to the existing security system maintenance plan.	NERC standard CIP-006 requires periodic testing of the system. Performing this testing with our existing perimeter alarm testing utilizes the same resources to perform both tests.
	Security system problem reporting and repairs are now considered urgent resulting in increased service calls	NERC standard CIP-006 requires the reporting and prompt response to problems.

7. List of Attachments

1. UI Service Territory Map
2. Line Clearance & Vegetation Management Specifications

ATTACHMENT 1

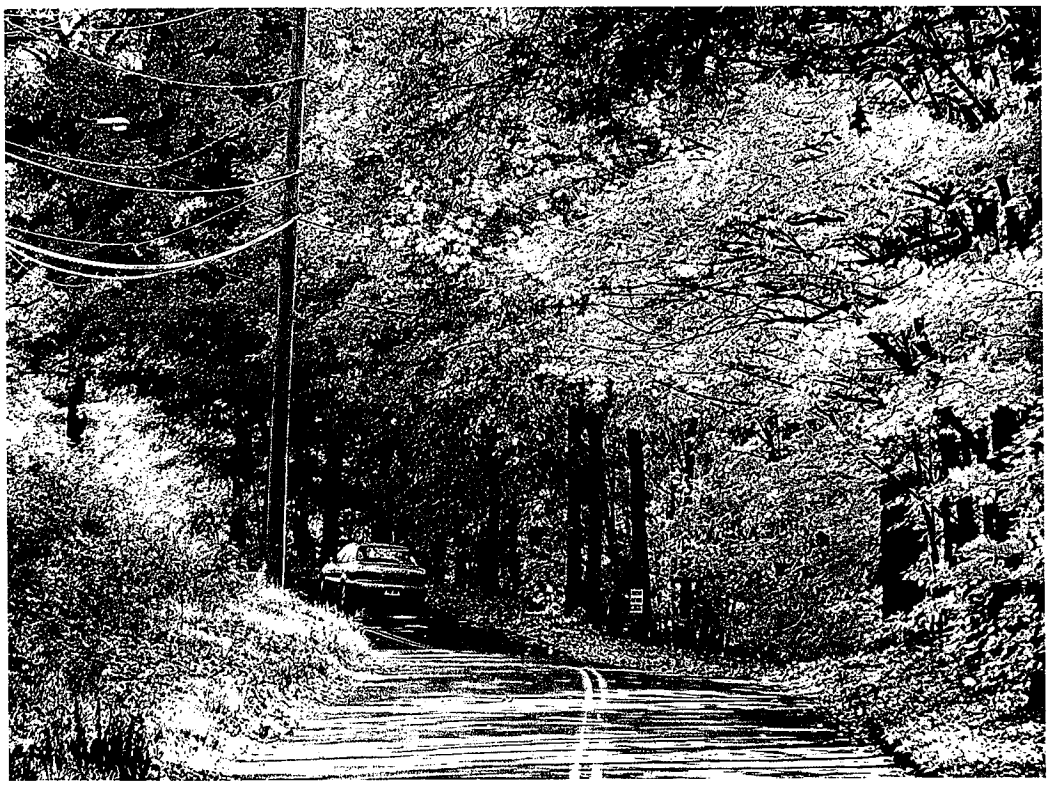
United Illuminating Service Territory Map



Fairfield County	New Haven County
Bridgeport	Ansonia
Easton	Derby
Fairfield	East Haven
Shelton	Hamden
Stratford	Milford
Trumbull	New Haven
	North Branford
	North Haven
	Orange
	West Haven
	Woodbridge

ATTACHMENT 2

Line Clearance & Vegetation Management Specification



The United Illuminating Company

Revised December, 2011

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Introduction

The United Illuminating Company (UI Co.) maintains its electrical system in accordance with the National Electric Safety Code. Pursuant to that code, UI is obligated to maintain adequate line clearance between trees and its conductors. UI's program meets these requirements and those of the State of Connecticut Department of Public Utility Control to ensure safe and reliable electric service to its customers.

Scope

The scope of this specification is to provide requirements and guidelines for line clearance pruning and the removing of trees, brush and other vegetation in close proximity to overhead electric distribution facilities located on public and/or private rights-of-way.

Regulations

All work practices and definitions, except as otherwise specified herein, shall be in accordance with all applicable Industry, Federal, State and Local laws and regulations, approved standards and safety practices.

These include, but are not limited to:

- OSHA 29CFR 1910.269 Electric Power Generation, Transmission & Distribution
- NERC FAC-003-1 Transmission Vegetation Management Program
- ANSI A300 "Standard Practices for Trees, Shrubs and Other Woody Plant Maintenance"
- ANSI Z133.1 "Pruning, Trimming, Repairing, Maintaining and Removing Trees, and Cutting Brush – Safety Requirements"
- NESC

- Connecticut General Statutes
- Department of Transportation
- Local Ordinances
- "Pruning Trees Near Electric Utility Lines" by Dr. Alex L. Shigo
- "Trenching & Tunneling Near Trees" by Dr. James R. Fazio, National Arbor Day Foundation

Clearance Requirements

A. Distribution Clearance Requirements

I. Standard Clearances

In general, the recommended tree to primary wire clearances is, where possible:

a. a minimum of six (6) feet side clearance,
b. twelve (12) to fifteen (15) feet clearance from overhanging limbs,
c. five (5) to eight (8) feet under-clearance.
d. Six (6) to ten (10) feet around poles.

The drawings on the following pages illustrate these general guidelines.

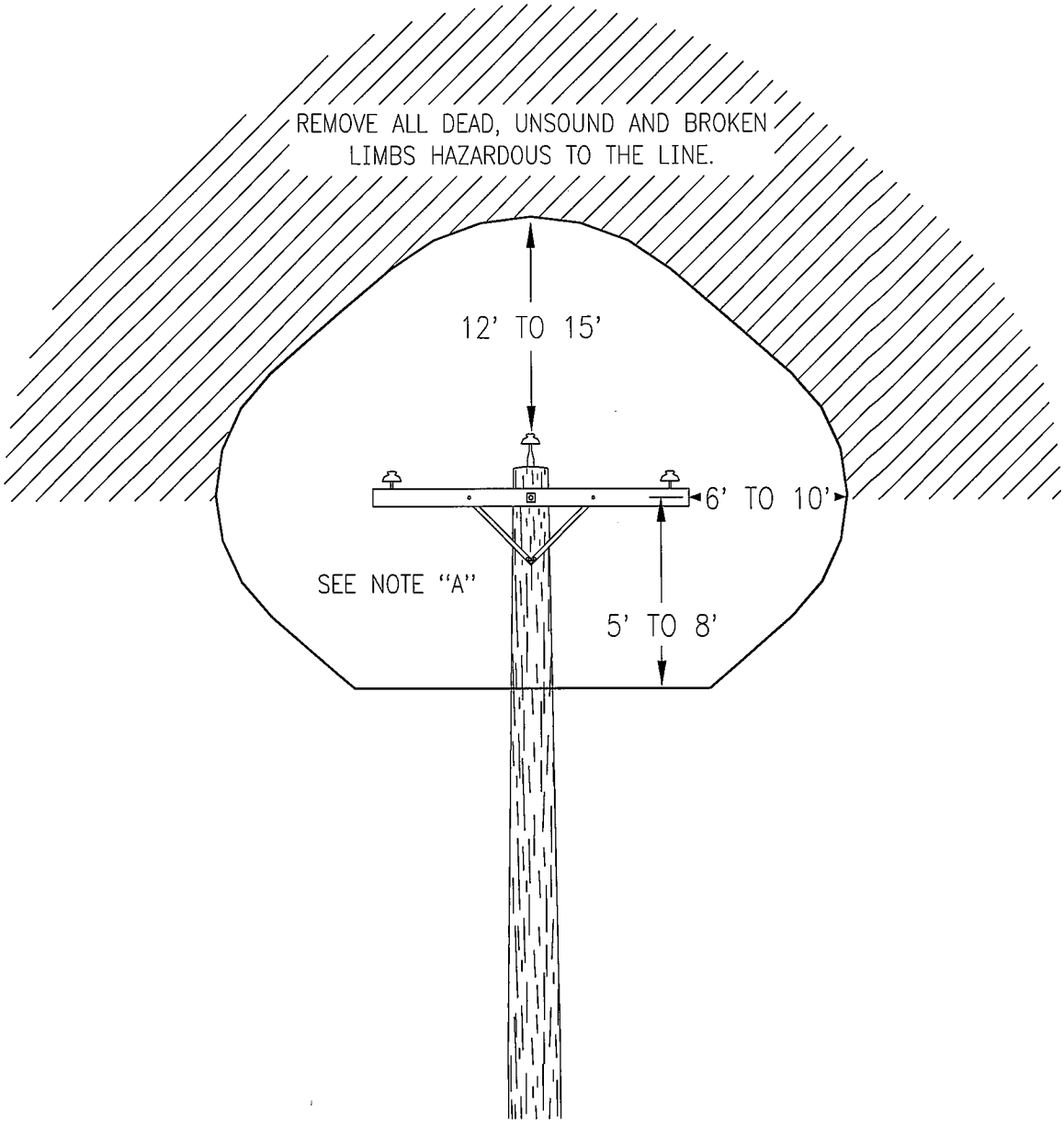
II. Evaluation

Because trees and vegetation respond directly to influences of nature and environmental conditions, the clearance requirements will vary. Each tree must be evaluated individually at the time it is trimmed.

This evaluation should include:

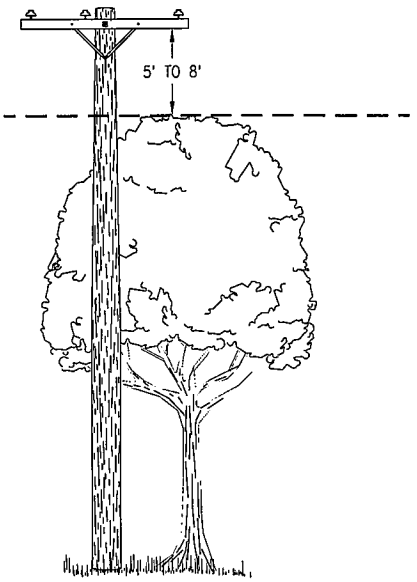
a. Voltage, construction and importance of the line.
b. Pruning cycle.
c. Growth rate, species, shape, condition and location of the tree.

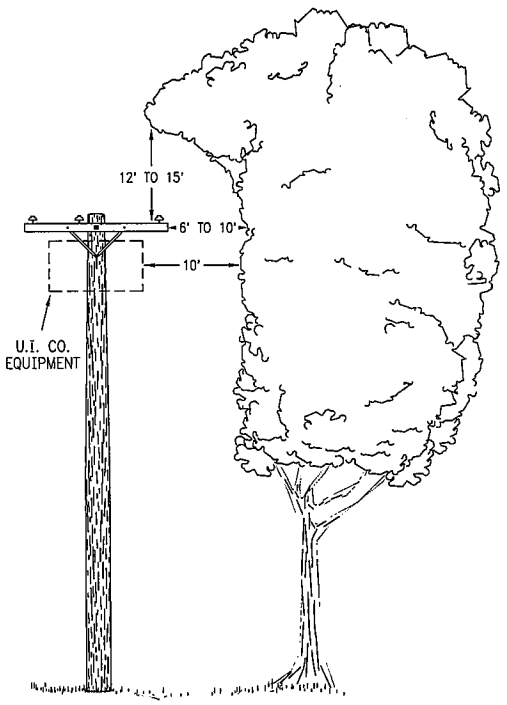
GENERAL RECOMMENDED CLEARANCES



NOTE "A"

CERTAIN MAIN BRANCHES ON OLDER TREES CAN REMAIN INSIDE OF THE MINIMUM CLEARANCE, BUT THIS DEPENDS ON THE HEALTH OF THE TREE, RATE AND DIRECTION OF GROWTH, AND SAFETY IN REACHING WIRES.





TYPICAL DIMENSIONAL CLEARANCES

Often times, the best or only suitable lateral that a branch can be pruned to is within or well outside of the standard clearance area. Exceptions are allowed, where judgment prevails that the removal of major limbs would drastically alter the shape of the tree. Such exceptions shall not result in unsafe conditions or interfere with the safe operation and maintenance of the line.

Consideration must also be given to the movement of branches and wires resulting in a change of clearance, due to storm and wind conditions.

III. Special Notes

Trees or limbs hazardous to the operation of the line, shall be patrolled for and every effort made to remove them.

Pole mounted electrical equipment such as transformers, capacitors, switches, etc. should be provided at least ten (10) feet of clearance.

Secondary and service cables should be cleared such that tree limbs do not rub on cables or entangle the wire.

Vines shall be removed from down guys and poles. If vines are in contact with energized wires, the worker while in a bucket, shall cut out a section of the vine stem measuring approximately one (1) foot in length starting at a point approximately 30 inches below the lowest electric wire. Then, the worker shall cut the vine at ground level. Report the location to UI's Line Clearance supervisor for further action by UI's crew.

Street Lights – The local municipality is responsible to perform routine maintenance trimming to maintain street light patterns on sidewalks and roadways. Conflicts with energized lines shall be referred to UI.

Private Area Lights – During routine maintenance, pruning should clear any vegetation on the pole which is obstructing the pole-mounted fixture.

B. Substation Clearance Requirements

Seasonal (usually May – October) grass cutting and shrub pruning are outlined in the contract/specification with UI's landscaper. Year-round maintenance work of the substation yard and its perimeter fence addresses security and safety concerns.

Trap rock within the fenced-in, energized areas must always be kept free of vegetation.

Maintaining a vegetation-free, substation ground surface reduces ground potential to workers in the substation yard. It also eliminates tripping hazards. Manual, mechanical, and pesticide means are all used to maintain a bare ground.

Outermost perimeter fences must be kept clear of all vegetation on both inside and outside. Also, to assure proper operation and avoid false alarms, perimeter alarm pedestals are to be kept free of vegetation.

Property boundaries and terrain permitting, a minimum of 10 feet outside of perimeter fences is to be kept clear of all tall-growing vegetation including no overhanging of the fence from abutting trees. Any potential climbing access to the substation yard is to be eliminated. For erosion control, grasses, ferns and other low-growing species are allowed in the 10 foot perimeter fence buffer zone. This buffer zone area is maintained once annually.

C. Transmission Rights-of-Way Clearance Requirements

Rights-Of-Way (ROW) clearing and maintenance shall be performed in accordance with The United Illuminating (UI) Transmission Vegetation Management Program (TVMP). The TVMP is in compliance with and adheres to guidelines set forth in NERC FAC-003-1.

Floor Maintenance:
All Rights-of-Way will be cleared of tall-growing and invasive species; leaving low-growing shrubs, ferns, forbs and grasses.

To provide for inspection of facilities, where terrain permits, vegetation will be cleared to allow for foot and/or vehicle access.

All encroaching side vegetation will be pruned back in accordance with ANSI A300 pruning standards.

While performing rights-of-way floor maintenance, and where possible/accessible, off right-of-way trees are to be inspected for their potential hazard to the conductors, towers, and facilities. The UI Transmission Vegetation Management Lead is to be notified for follow-up inspection, immediately after a potentially hazardous tree is located.

Site conditions dictate the best and most efficient method to clear utility rights-of-way. No right-of-way terrain is level for its entire length. Additionally, UI rights-of-way traverse a variety of field conditions including grades greater than 45 degrees, wetlands, and swamps, landscaped private property, and areas inaccessible by any vehicle. Consequently, the use of manual, mechanical, herbicide, or other vegetation control methods will be implemented where most practical. Note: The use of herbicide on UI Rights-Of-Way is currently under consideration for use and is being evaluated. There is currently no use of herbicide on UI Rights-Of-Way.

The Line Clearance contractor working on the United Illuminating's Rights-of-Way is to adhere to all applicable federal, state and local laws and ordinances. The rights of abutting property owners are also respected and a "good neighbor" policy adhered to.

D. Distribution Rights-of-Way Clearance Requirements

I. General

Distribution rights-of-ways (R.O.W.) are to be maintained clear of trees to permit access for line maintenance and provide for safe operation. Such land strips are usually occupied and maintained under long term easements. When any doubt exists as to tree rights on a private R.O.W., contact the Line Clearance Supervisor or Arborist.

II. Maintenance

All trees and saplings shall be removed as close to the ground as practical and to a suitable distance back on both sides of the line, to provide necessary ground to sky clearance.

Vines on poles, towers and fixtures shall be cut.

Brush shall be handled in such a manner as to avoid obstructing roadways, pathways, and waterways or leaving a distinct fire hazard.

Potential problem trees outside an established R.O.W. shall be removed as directed by UI's Line Clearance Supervisor/Arborist or crew foreman after the customer's permission has been obtained.

Methods/Practices

I. General

Directional pruning shall be used to guide tree growth away from wires. As a general rule, cuts shall not be treated with "Tree Paint".

The line clearance workers are to use their professional judgment and knowledge to obtain the necessary clearances based upon the planned Program Trim Cycle for the area they are working in.

Climbing irons or "hooks" should not be used except in cases involving tree removal work or where field conditions make vehicular access impossible.

The completed job shall result in satisfactory operation of the Overhead Distribution System during normal inclement conditions.

II. Tree Removal

Consistent with satisfactory line clearance, public relations and appearance, it is desirable to remove trees under certain conditions rather than proceed with trimming. These conditions include:

a. Trees which remain unsightly due to excessive pruning.
b. Badly deceased, dead or dying trees.
c. High maintenance trees.

Removals must be coordinated by the Line Clearance Supervisor with the local municipal tree warden and/or property owner. Trees shall be removed in a manner causing no damage to adjoining public or private property.

DO NOT undertake any work involving a severe hazard to overhead line operation without first contacting the UI Line Clearance Supervisor or representative.

III. Tree Stump Removal

Tree stump removal is normally the jurisdiction of the local municipality or private property owner.

Stumps on private R.O.W.'s shall be cut low enough to permit unhindered travel of motorized equipment.

IV. Brush

A woody plant with a stem measuring less than five (5) inches DBH is considered a brush. Brush shall be cut to the ground line where topography and obstructions will permit.

V. Clean up & Disposal

All brush and debris resulting from scheduled routine work shall be completely removed from the work area (e.g. fine twigs and litter removed from lawns, the street, sidewalks and driveways).

Brush or wood shall not be allowed to remain on public thoroughfares or on private property overnight unless arrangements have been made by the contractor's crew leader or UI Supervisor with the authorities or property owner.

All line clearance by-products (e.g. brush, wood chips, logs, wood, etc.) must be disposed of at approved sites and in the most economical way. Brush or wood shall not be burned.

NOTE: *The removal of brush and debris resulting from a storm is normally not the utility contractor's responsibility, unless otherwise authorized by UI.*

Contractor Responsibilities

I. General

The Contractor is responsible to provide the Company with workers that are properly trained to perform their work competently and deal with the public with professional courtesy at all times.

All work shall be in accordance with recognized and approved arboricultural standards and perform in accordance with all Federal OSHA, ANSI, State and Local requirements appropriate for such work. The contractor will also comply with the Contract terms, rules and specifications established by United Illuminating for such work.

Contractor is to obtain all permits and licenses imposed by law, pay all charges and fees, and give notices necessary and incidental to the due and lawful prosecution of the work.

Contractor is to provide certified copies of liability insurance coverage for public and private liabilities which may arise in connection with their work.

Contractor is to provide all labor, tools, equipment, transportation and materials to perform line clearance work. Apparatus shall be in proper operating condition and adequately maintained.

Contractor shall provide employees with suitable foul weather gear and other apparatus necessary to perform night emergency work. The contractor's equipment shall be neat appearing. Appropriate first-aid supplies, as required by OSHA, shall be a part of the standard equipment on all vehicles.

Adequate spare equipment and tools shall be readily available to insure that workers are not delayed in performing the required work. The billing rate for equipment shall be all-inclusive including, but not limited to: fuels, lubricants and maintenance, hand and power tools.

Each crew is to have a copy of these standards and specifications and Dr. Shigo booklets ("Pruning Trees Near Electric Utility Lines) on each crew truck/work location.

II. Safety

The contractor shall take the necessary precautions to prevent personal injury or damage to property and shall conduct operations with a minimum of interference to traffic or inconvenience to the public.

In this area of safety and health, the contractor shall:

a. Observe the contractor's safety rules at all times.
b. Treat every circuit and/or line as energized.

If in the judgment of the contractor's foreman, it is hazardous to perform the assigned work with the circuit energized, UI supervision shall be contacted. The necessary protective line hardware or de-energized circuit(s) will be provided by UI.

III. Damage Notification

The contractor foreman is to notify the UI Supervisor or representative, as soon as possible, of all defects, damage, etc., observed on UI overhead facilities (e.g. wire off, pole top pin, broken basket, etc.). Dangerous conditions should be reported immediately.

IV. Work Assignments

Line clearance work addresses three major categories: Program Maintenance, New Construction and Customer Requests. In general, since the integrity of the mainline affects more customers, distribution trimming should start from the substation out in order to clear the three phases mainline before the side taps.

Each morning the crew foreman is to report to the UI Line Clearance Supervisor his progress from the previous day and obtain his daily work assignment. Any changes made in the assignment during the day shall be immediately reported.

UI will provide necessary maps and reports forms to the contractor indicating the planned work area.

UI Supervision reserves the right to re-assign a crew(s) from their normal work area to a temporary work area as conditions warrant.

V. Traffic Control

The Contractor will be responsible for coordinating and scheduling of traffic control for all work billable monthly as a separate item and passed through (no mark up) to UI with back up.

VI. Reports

The foremen of each crew shall record necessary information on UI's contractor daily time sheet and the contractor's weekly Operation Report indicating the nature and extent of work performed. These forms are to be provided to the Area Line Clearance Supervisor at the end of each working week. In addition, the contractor is to provide UI a monthly summary report of their performance as required by UI.

VII. Public Contact

A. Permissions

1. New Construction

   Permission is usually obtained by the UI Customer Engineering Department Representative as part of the planned development. This representative is to advise the customer that they are responsible for site preparation work (e.g. vegetation clearance) before a new pole line is installed.

2. Maintenance

   The contractor, as an agent for UI, is to request permission from the adjoining property owner to trim trees around electric conductors on public or private property. In the interest of public relations, it is the Contractor's responsibility to advise the owners that they will be in a given area performing line clearance work. Realize that we must return to this location in the future, so it is imperative that the customer is satisfied with our workmanship. Therefore:

   a. Confirm that the person you are speaking to is the property owner.
   b. Clearly identify exactly what needs to be trimmed to maintain safe, reliable electric service.
   c. Once an agreement has been reached, repeat and confirm the plan.
   d. If the property owner is not home, leave an approval request card on the door. Refer to UI's "Customer Approval Procedure" for more detailed information.

   Contractor is not to obligate UI to make any payments to another party, nor make any promises or representations of any nature to another party for, or in behalf of UI, without prior approval of UI.

3. State Highway

   Crew must have a copy of the State Tree Trimming Permit with Permit Number when doing work on a State Highway.

B. Complaints

In handling any complaints, the contractor shall use its best efforts to maintained and promote good public relations. The contractor shall not make payment to local inspectors, property owners or any other persons for any right to trim or remove trees.

The contractor shall immediately inform the Line Clearance Supervisor of any damage complaints from a customer, regardless of the cause or extent of damage and of all resolutions and settlements.

The contractor shall give immediate attention to, and shall use its best efforts to promptly, courteously and equitably respond to, adjust and/or settle, without obligation to the UI, all complaints received by the contractor from third parties arising out of, or in connection with, performance of their work.

C. *Customer Relations*

Contractor crew members are UI representatives to our customers. Consequently, each person is expected and required to treat the customer in a professional and courteous manner.

Numerous contacts with local municipalities and customers provide an excellent opportunity to make a positive impression. A worker's appearance, attitude and methods of approach must reflect creditably upon the Company. They must possess a good knowledge of human nature, arboriculture and have the ability to quickly evaluate situations to secure tree work permissions and, at the same time, establish friendly relations.

Glossary

Brush	A woody plant less than 5 inches in diameter at DBH
Clearance	The distance from the conductor to the part of the tree that will interfere with or grow in to the conductor first.
Crew Foreman	The tree contractor's crew leader (male or female) working with and supervising the line clearance crews.
Diameter Breast Height (DBH)	Diameter of tree or brush at a point 4 ½ feet above the ground.
Drop-Crotching	See "Natural Trimming"
General Foreman	Supervisory personnel (male or female) working for the contractor who has responsibility for work performed by that particular contractor's tree crews.
Ground-line Cutting	Completely removing trees or brush at the ground line.
Hotspotting	Assigning tree trimming crews in a manner that does not involve systematic, scheduled program maintenance work.
Line Clearance	Controlling vegetation to maintain proper clearance from conductors. Synonymous with tree clearing, tree trimming or vegetation management.
Natural Trimming	Trimming to reduce the height and/or spread of a tree, while attempting to maintain the tree's natural form, by cutting branches back to a lateral limb, towards the center of the crown. A method by which branches are cut to the branch collar at a suitable parent limb back toward the center of the tree. This method of trimming is sometimes called "drop-crotching" or "lateral, trimming". Natural trimming is also directional trimming, since it tends to guide tree growth away from wires.
Overhanging Limbs	Tree limbs extending over the top of conductors.
Pruning	The removal in a scientific manner of dead, dying, diseased, interfering, objectionable, and/or weak branches.
Removal	Completely removing an entire tree to ground level; required when a tree is described as danger tree or when a tree should be removed for other reasons.

Removal Zone	An area on the right-of-way, below and extending beyond the conductors, where tree removal and brush clearance are recommended.
Rounding Over	Not recommended. The making of many small cuts so that the tree top is sheared in a uniform line. This creates an unhealthy tree condition and results in rapid regrowth directly back toward the area intended to remain cleared.
Sag	The vertical distance that a conductor will drop due to heavy load current and/or high temperature.
Shearing	See "Rounding Over"
Shrub	A woody plant normally maturing at less than 15 feet in height, presenting a generally bushy appearance because of its several erect or spreading stems.
Side Trimming	Cutting back or removing the side branches that are threatening the conductors; required where trees are growing adjacent to conductors.
Species	The basic category of biological classification intended to designate a distinct group or kind of plant or animal having common attributes.
Sway	The horizontal distance that a conductor will move due to wind.
Top Trimming	Cutting back large portions of the upper crown of a tree; required when trees are located directly beneath a conductor.
Tree	A woody plant normally maturing at 15 feet or more in height, usually with a single trunk, unbranched for several feet above the ground with a definite crown. Any trunk that is 5 inches or over DBH shall be considered a tree.
Tree Crown	Upper portion of the tree; the branches or leaf area.
Trimming	See "Pruning"
Trim Cycle	The period of time between when a tree is trimmed and trimmed again.
Trim Paint	A wound dressing applied to cut surfaces on standing trees. Application of such paint is **not** recommended.
Under Trimming	Removing limbs beneath the tree crown to allow wires to pass below the tree.

General Worker Guidelines

First impressions count!

The following items are important to remember at all times:

Crew Image

- ✓ Be neat in appearance.
- ✓ Have an orderly appearance of the work vehicles.
- ✓ Be professional in conduct and attitude.
- ✓ Have energetic work habits.

Public Relations

- ✓ Be courteous and sociable.
- ✓ Be attentive to customer's concerns.
- ✓ Have respect for the customer's property.
- ✓ Leave the area as you first found it (or better).

Job Knowledge

- ✓ Conduct a "Tailboard Conference" before starting the job (e.g. Confirm what, who, where, why, etc.).
- ✓ Prepare before approaching a customer (e.g. Have in mind the importance to trim the line, the species of tree involved, type of trim needed, etc.).
- ✓ Have confidence in yourself.

Communication

- ✓ Control the volume and tone of your voice.
- ✓ Maintain professional body language.
- ✓ Concentrate on what the customer is saying. Don't interrupt.
- ✓ Don't draw premature conclusions. Ask questions.
- ✓ Identify clearly what work is to be done. Confirm it.
- ✓ Trim only what had been discussed.

You represent the UI Company and are expected to treat the customer with respect and value

The United Illuminating Company

LINE CLEARANCE

CUSTOMER APPROVAL PROCEDURE

Dated 7/16/07

LINE CLEARANCE

CUSTOMER'S APPROVAL PROCEDURE

I. Preface

Keeping trees and limbs clear of United Illuminating's overhead Transmission and Distribution system is necessary to ensure safe, reliable electric service to our customers. In recognition of the interests and value of trees being properly maintained, we seek through better mutual understanding to gain the customer's permission and minimize refusals to perform needed work.

II. Purpose

This procedure provides an organized process for obtaining a customer's permission to perform *routine* line clearance work and report cases where permission has not been granted.

III. Scope

Applies to line clearance work performed on UI's overhead Transmission and Distribution System.

IV. Responsibilities

Contractor:

1. Obtain permission from customers within planned work area before starting actual work. If the customer is not home, a "door knob hanger" notice should be left discreetly (i.e., not to advertise that no one is home. Two additional attempts should be made to obtain permission using door hangers.

2. Where permission has not been obtained after three attempts, the contractor crew foreman is to complete the "Customer Permission—follow-up" form (see Exhibit A). Regarding Distribution system reporting, special note should be made to identify: "Serious" Conditions (e.g. burn marks, limb heavy on wire, etc.) OR "Non-Serious" Conditions using the Customer Permission –follow-up form. Regarding UI's Transmission system, use NERC critical forms Clearance 1 and 2 for reporting locations not meeting those standards. Note the "Job Issue" or difficulty (customer permission, access problem, permit/legal issue, or arboricultural issue) that prevents sufficient clearance for being obtained. (see Exhibits B & C). United Illuminating employees, Line Clearance contractors – both tree contractors and ROW inspection contractors are to notify the The Transmission Vegetation Management Lead or designee via cell phone immediately of any locations that do not meet the NERC FAC-003-1 Clearance 2 standard. (clearance distance of 10 feet for 345KV and 4 feet for 115KV lines)

   These forms should be forwarded to the UI Line Clearance Arborist or designee at the end of each week. In addition, "Serious" Conditions are to be reported to Supervision verbally when found.

UI Arborist or Designee:

Distribution

1. Line Clearance Arborist or designee are to review all reports forwarded by the contractor and proceed as follows:

a. Serious Conditions

i. If the customer cannot be contacted in person, a letter and permissions postcard is to be sent requesting their permission (see Exhibit D). If no response is obtained within ten (10) working days, contact next level of supervision.

ii. If the customer agrees to a light trim only, so note for future follow-up.

iii. If the customer refuses to grant permission, note and explore other engineering alternatives (e.g. out rig construction, armless construction, contact tree warden).

b. Non-Serious Conditions

i. If the customer cannot be contacted in person, the Line Clearance Arborist or designee will instruct the Contractor General Foreman to pursue obtaining permission. A follow-up report is to be provided to UI's Arborist (i.e., full/partial/no permission granted, no contact made, etc.).

ii. Line Clearance Arborist or designee are to prepare a summary report with copies of "Customer Approval Follow-up" forms on a quarterly basis. This report is to be sent to UI's Reliability Engineer (System Integrity) for record and is reported to the Department of Public Utility Control (DPUC).

Transmission

1. The Transmission Vegetation Management Lead or designee is to review all reports and forms forwarded by the Line Clearance and ROW inspection contractors and will proceed as follows:

   a. Re-Inspect all locations reported as not meeting either Clearance 1 or 2 this is to verify the information reported.

   b. The Transmission Vegetation Management Lead or designee works with the property owner, the Line Clearance Tree Contractor; UI's Transmission Operations, Real Estate, and Legal Departments to secure permissions to achieve the clearances necessary to meet the standards.

   c. Any unresolved and unmitigated issues are reported by location to UI's Transmission Operations, Real Estate, and Legal Departments for review to explore any alternatives for eventual mitigation and resolution for the issue.

A schematic diagram is attached as Exhibit E that depicts the process of gaining permissions and tracking all locations that do not meet the NERC FAC-003-1 standards (Clearances 1 & 2).

EXHIBIT A

CUSTOMER'S PERMISSION FOLLOW-UP FORM
L.C.D.

DATE:	
CUSTOMER:	
ADDRESS:	
TOWN:	

CIRCUIT #:	POLE #:	POLE#:	TILE#:

CONDITION IS: SERIOUS ☐ NON-SERIOUS ☐
AT THIS TIME.

DESCRIBE CONDITION:

	NO CONTACT (NOT HOME/ PARKED CAR)	LIMITED TRIM (NOT TO SPEC)	NO TRIM (REFUSAL)
CREW FORMAN			
PERMISSION'S PERSON			
GENERAL FOREMAN			
UI LCS			

(ENTER NAME UNDER CATEGORY)

CUSTOMER'S COMMENTS:

EXHIBIT B

UI LINE CLEARANCE

NERC CLEARANCE 1 ISSUES

LOG SHEET

The list below is a compilation of locations logged by the Tree Contractor where CLEARANCE 1 (NERC FAC-003-1) could not be obtained.

LINE #	TWN	ST. REFERENCE	TOWER/ CAT.#	BRIEF WORK DESCRIPTION	Signs of Burning	MN FLAG?	MN Ground?	UI LINE OUT?	TOWN FD?	JOB ISSUE	OUTAGE LENGTH	Tent.START DATE	COMPL DATE
										Cust.Perm. Access Permit Legal Bucket Climb(s)			
										Cust.Perm. Access Permit Legal Bucket Climb(s)			
										Cust.Perm. Access Permit Legal Bucket Climb(s)			
										Cust.Perm. Access Permit Legal Bucket Climb(s)			
										Cust.Perm. Access Permit Legal Bucket Climb(s)			
										Cust.Perm. Access Permit Legal Bucket Climb(s)			

kb/NERC critcal CLEARANCE 1 log sheet.xls

Forward list to the UI Line Clearance Dept. along with all weekly paperwork.

EXHIBIT C

UI LINE CLEARANCE

NERC CLEARANCE 2 ISSUES

LOG SHEET

The list below is a compilation of locations identified via the annual ROW foot inspection that do not conform with CLEARANCE 2 of NERC FAC-003-1 (IEEE 516-2003)

LINE #	TWN	ST. REFERENCE	TOWER/ CAT.#	BRIEF WORK DESCRIPTION	Signs of Burning	MN FLAG?	MN Ground?	UI LINE OUT?	TOWN RD.?	JOB ISSUE	OUTAGE LENGTH	Tent.START DATE	COMPL DATE
										Cust.Perm. Access Permit Legal Bucket Climb(s)			
										Cust.Perm. Access Permit Legal Bucket Climb(s)			
										Cust.Perm. Access Permit Legal Bucket Climb(s)			
										Cust.Perm. Access Permit Legal Bucket Climb(s)			
										Cust.Perm. Access Permit Legal Bucket Climb(s)			
										Cust.Perm. Access Permit Legal Bucket Climb(s)			

kb/NERC critcal CLEARANCE 2 log sheet.xls

Forward list to the UI Line Clearance Dept. immediately upon completion

EXHIBIT D

SAMPLE (1) FOLLOW-UP LETTER FOR PERMISSION

UI LETTERHEAD

Dear [ ]

We need your help in providing you and your neighbor's safe and reliable electric service.

Our contracted tree crews have been trimming trees on your street and in your neighborhood as part of our Line Clearance maintenance program. This program is necessary to ensure that trees do not interfere with the operation of the electric wires and equipment that serve you.

We need the cooperation of every resident in your area to complete this work—and with your permission we can do so.

Please take a moment now to sign and mail the enclosed, pre-stamped permission card. If you have any further questions, please feel free to call me at the following phone number: [ ]

Thank you for your anticipated cooperation.

Sincerely,

Line Clearance Arborist/Supervisor

EXHIBIT D

SAMPLE (2) PERMISSION POSTCARD

☐ I hereby grant the United Illuminating Company's contractor permission to do necessary tree work on public/private property to clear the electric lines.

I understand there is no cost to me for this work.

☐ Please contact me before starting any work. The best time to call is

TIME: _____ a.m. / p.m.

If you are not the owner, please advise who the owner is.

Thank you,

Owner's Signature: _____

Owner's Name (print): _____

Address: _____

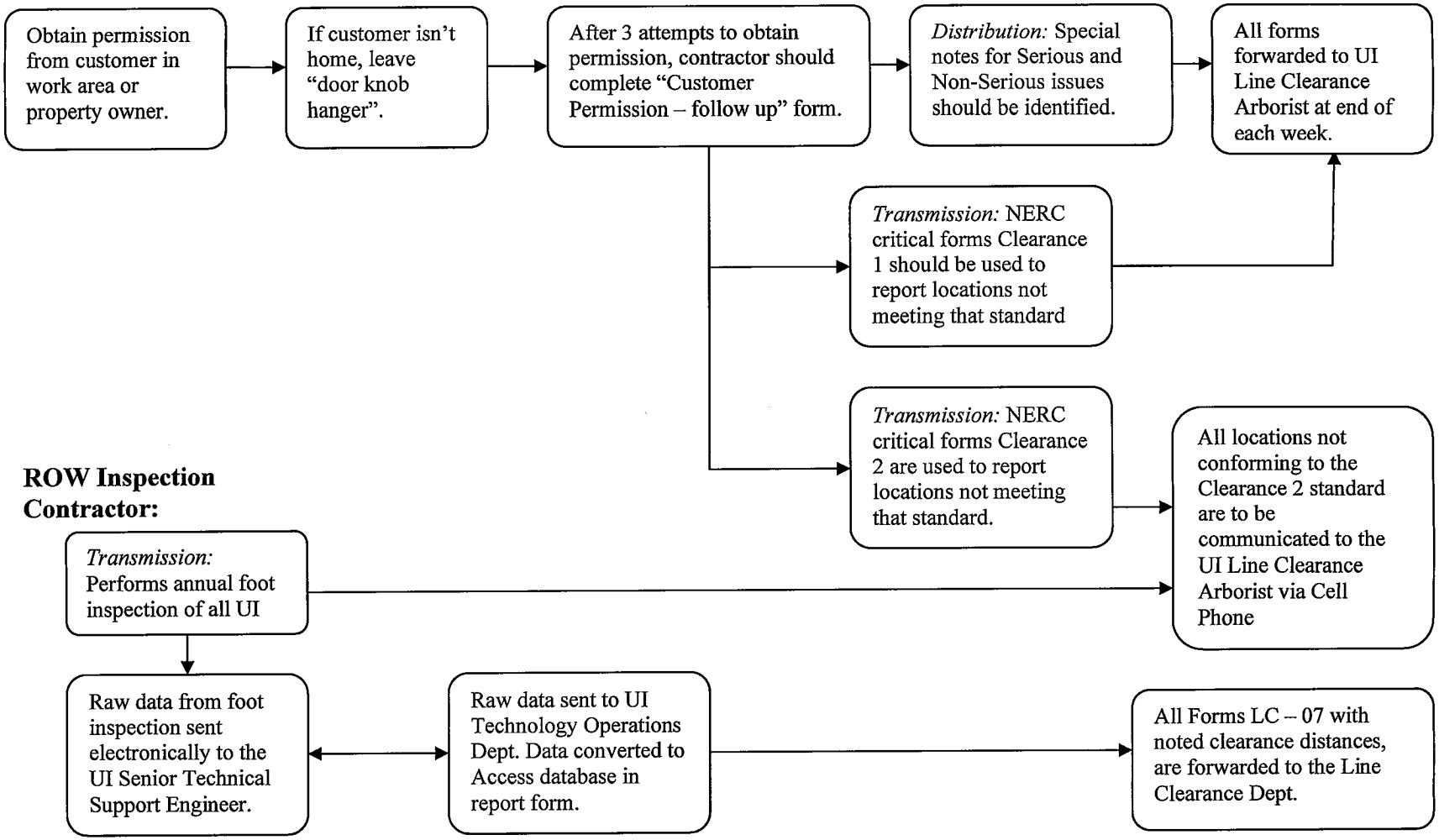
_____

Phone #: _____

EXHIBIT E

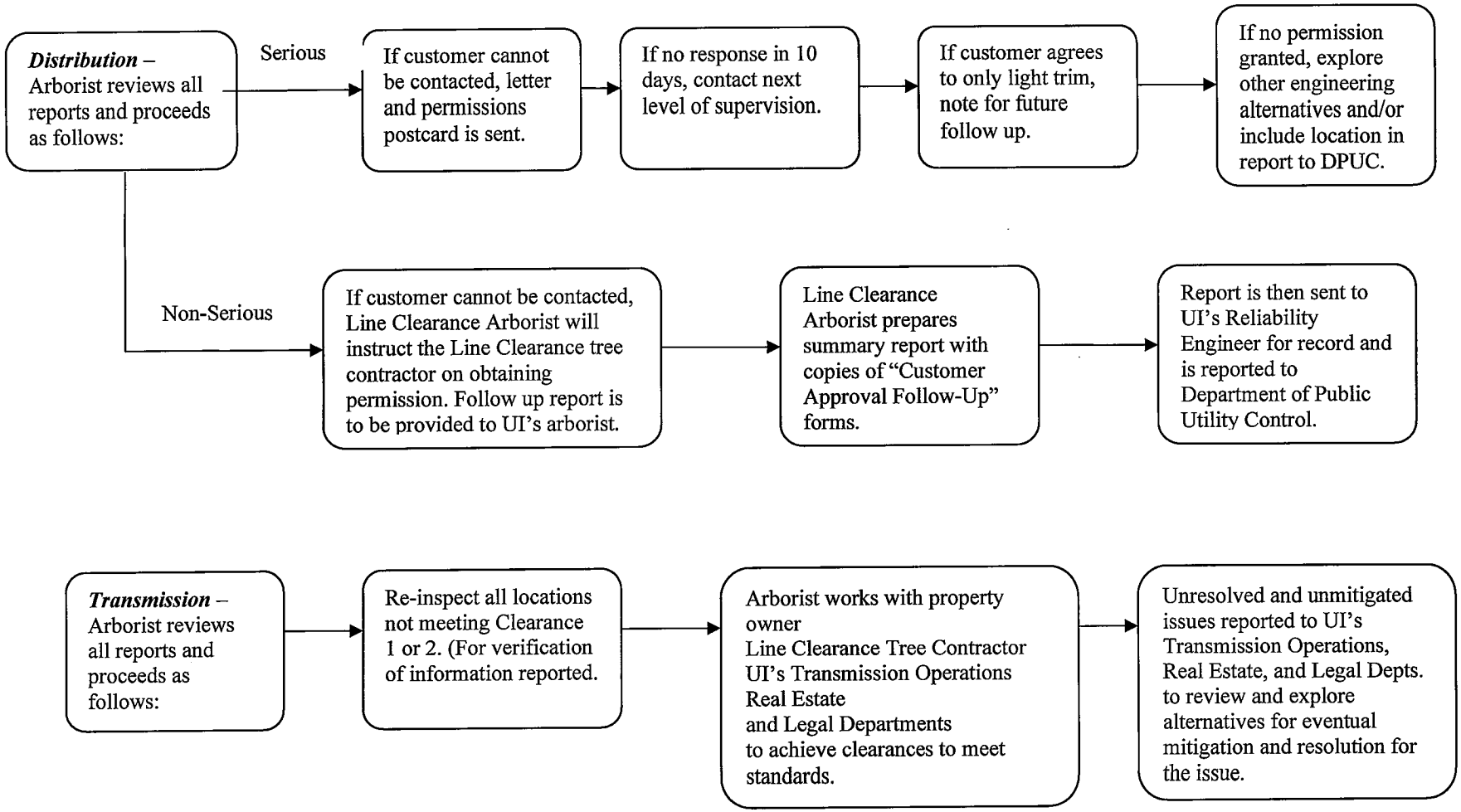
SCHEMATIC DIAGRAM OF PROCESS OF GAINING PERMISSIONS AND TRACKING LOCATION VIOLATING STANDARDS

Tree



Contractor:

UI Arborist or Designee:



APPENDIX D

PUBLIC UTILITY REGULATORY AUTHORITY, *WHAT IS THE GAS PIPELINE SAFETY UNIT?*

State of Connecticut Public Utilities Regulatory Authority

What is the Gas Pipeline Safety Unit Inspection Program?

Intrastate Facilities

1. General

The Gas Pipeline Safety Unit uses a combination of field inspections of new construction, and operation and maintenance of pipeline facilities and plants, as well as reviews of company plans, procedures and records, to ensure compliance with applicable safety requirements. Statistical information and risk assessments are used to focus the program. Inspections are performed by qualified engineers with specific training in the field of pipeline safety. The Gas Pipeline Safety Unit performs over 300 field inspections per year.

2. New Construction

The Gas Pipeline Safety Unit selects certain new construction activities to be inspected to ensure that the facilities are installed properly, in accordance with applicable State and federal requirements and the company procedures. If the facilities are installed properly, they should provide safe service for a long, long time. The inspection includes ensuring that persons performing safety sensitive tasks are properly qualified in accordance with the Operator Qualification requirements and are aware of the abnormal operating conditions associated with those functions.

3. Procedure and Records Audit

Gas companies are required to develop and follow detailed written plans, and to review their plans and procedures periodically to ensure completeness, clarity and compliance with applicable State and federal safety requirements. The Gas Pipeline Safety Unit reviews the plans and programs, including records of the facilities, to ensure compliance with the plans and procedures. These cover:

i. the design and construction of pipeline facilities;
ii. routine operation and maintenance of facilities;
iii. emergency plans to respond to problems with the system, including coordinating response with local emergency response personnel;
iv. operator qualification programs to ensure that gas company personnel have the necessary knowledge, skills and ability to safely and properly perform safety sensitive tasks, including recognizing potential problems;
v. procedures for investigating accidents and failures
vi. procedures for evaluating the integrity of the existing pipeline system and developing criteria and plans for pipeline replacement to ensure the safety of the gas facilities.

4. Operation and Maintenance Inspections

The Gas Pipeline Safety Unit reviews actual operation and maintenance activities of the gas operators to ensure compliance with applicable requirements and record keeping associated with those activities. The inspection includes ensuring that persons performing safety sensitive tasks are properly qualified in accordance with the Operator Qualification requirements and are aware of the abnormal operating conditions associated with those functions.

5. Pipe Replacement Programs

Gas companies have mandatory risk-based pipe replacement programs. Using the best available technical and engineering data, facilities are evaluated based on particular factors to identify those facilities that seem to represent the greatest danger to public safety. These facilities are targeted for attention. In addition, pending replacement of facilities, additional leakage surveys may be performed

to provide increased levels of attention where safety concerns are the greatest. A new Distribution Integrity Management Program (IMP) includes additional leakage survey and other requirements to risk-manage the distribution systems.

6. Damage Prevention Programs

Since damage by excavation activity is one of the primary causes of serious natural gas incidents, each gas operator has a program designed to minimize damage from excavation activity. The center point of this is the State excavation damage prevention program and one-call system.

7. Incident Investigations

When a significant incident occurs, the Gas Pipeline Safety Unit performs an investigation as to the cause of the incident. Under State and federal law, the PURA has the statutory authority and obligation to investigate pipeline failures and incidents. The Gas Pipeline Safety Unit has authority to ensure necessary safety activities of the gas operators to protect the public and emergency responders, as well as overseeing the safe restoration of any facilities that are shutoff. The Gas Pipeline Safety Unit works cooperatively with other governmental agencies at incidents to determine hazards, safely deal with the hazards, resolve any safety issues, and investigate the causes of the incident. Cooperative efforts, using the expertise and professional competence of all parties, ensures public safety. The objective of the investigation is to determine the cause of the incident in order to minimize a recurrence of that type of failure. View a list of incidents.

8. Review Reports

The Gas Pipeline Safety routinely receives reports of various kinds about the pipeline systems, including leak reports, employee accident reports and excavator damage reports. We routinely receive inquiries from excavators, customers and the general public related to issues of pipeline safety.

9. Fire Department Training

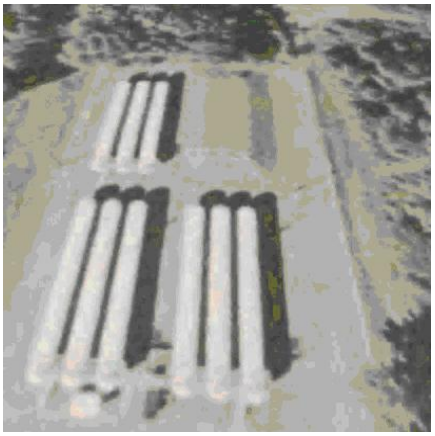
In cooperation with the gas operators, the Gas Pipeline Safety Unit is active in providing training for local fire departments and other emergency responders regarding gas incident. It is the obligation of all interstate and intrastate pipelines to coordinate with local officials in planning for potential emergencies. Emergency responders are encouraged to attend such training sessions. If they feel a need for additional training or information, they should contact the gas operator or the Gas Pipeline Safety Unit.

10. LNG and LP-Air Plants

Liquefied Natural Gas (LNG) plants are facilities for making LNG (or receiving LNG by truck), storing the cryogenic liquid (-260°F) until times of peak demand, and vaporizing the LNG for use by customers throughout the distribution system.

Liquefied petroleum gas-air plants take liquid propane from storage tanks, vaporize it, mix it with air, and intermix that with natural gas to supplement gas supplies at times of high demand.

These facilities are inspected annually by the Gas Pipeline Safety Unit to ensure compliance with applicable safety requirements and to ensure they are ready to provide the necessary service to gas customers.

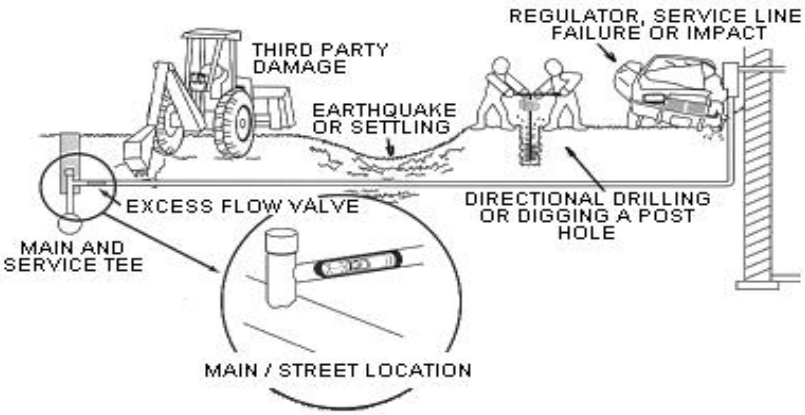


11. Integrity Management Program

Work has been underway for several years at the federal level to develop new regulations to require each distribution operator to develop a Distribution Integrity Management Plan (IMP). Connecticut has actively worked with OPS in the Distribution IMP process. The Distribution IMP regulations became effective August 2, 2011. The distribution IMP program requires a written plan to address seven elements:

i. Know the distribution systems and how these are designed, operated and maintained
ii. Identify threats to their system
iii. Evaluate and rank risks to their system
iv. Identify and implement appropriate measures to address risks
v. Measure performance, monitor results and evaluate effectiveness
vi. Periodically evaluate and improve the program
vii. Make periodic reports to government agencies as required

In addition, there are requirements for the use of an Excess Flow Valve (a device installed in a gas pipeline to automatically restrict or shut off the gas flow through the line when the flow exceeds a predetermined limit) (EFV) on certain service lines.



In Connecticut, we have been active historically in integrity programs to improve the safety of Connecticut citizens. We have developed risk management programs to identify and implement additional and accelerated operation and maintenance activities, such as more frequent leakage detection surveys, as well as risk-based pipeline replacement programs. Also, it has been standard practice to install EFVs where their use is practicable.

Interstate Operations

1. General

The Gas Pipeline Safety Unit coordinates with the Pipeline and Hazardous Materials Administration (PHMSA) Office of Pipeline Safety (OPS) Eastern Region in developing an annual inspection plan for the interstate operators in Connecticut . It uses a combination of field inspections of new construction, and operation and maintenance of pipeline facilities and plants, as well as reviews of company plans, procedures and records, to ensure compliance with applicable safety requirements. Inspections are performed by qualified engineers with specific training in the field of pipeline safety.

2. New Construction (see A2 above)
3. Procedure and Records Audit (see A3 above)
4. Operation and Maintenance Inspections (see A4 above)
5. Pipe Replacement Programs (not directly applicable, see A above)

Interstate transmission lines are subject to extensive regulations related to IMP. This requires detailed analysis of the current state of the pipeline system and remedial actions where necessary to ensure the integrity of the pipeline.

6. Damage Prevention Programs (see A6 above)
7. Incident Investigations (see A7 above)
8. Review Reports (not directly applicable, see A8 above)
9. Fire Department Training (see A9 above)
10. LNG and LP-Air Plants

There is one interstate LNG plant in Connecticut. It is inspected at least once a year.

11. Integrity Management Program

Transmission lines are subject to extensive regulations related to development and implementation of an Integrity Management Program (IMP). This requires detailed analysis of the current state of the pipeline system. A key analytical tool is a "smart pig" (right), a sophisticated instrument device run through the pipeline to identify certain integrity issues that may exist in a transmission line. Smart pigs may detect corrosion, damage to the external coating that helps to prevent corrosion, damage to the pipe during initial construction or as a result of damage by excavation by others. Any integrity issues are identified, evaluated and any necessary remedial actions are taken.

Gas Pipeline Safety

Content last updated May 2012

APPENDIX E

DEPARTMENT OF ENERGY & ENVIRONMENTAL PROTECTION, *2012 INTEGRATED RESOURCE PLAN FOR CONNECTICUT*

2012 Integrated Resource Plan for Connecticut

Prepared by:

The Connecticut Department of Energy and Environmental Protection

June 14, 2012

Connecticut Department of
ENERGY &
ENVIRONMENTAL
PROTECTION

June 14, 2012

Sen. John W. Fonfara, Co-Chair
Rep. Vickie Orsini Nardello, Co-Chair
Sen. Bob Duff, Vice-Chair
Rep. Lonnie Reed, Vice-Chair
Sen. Kevin D. Witkos, Ranking Member
Rep. Laura Hoydick, Ranking Member

Energy and Technology Committee
Room 3900 Legislative Office Building
Hartford, CT 06106

Sen. Edward Meyer, Co-Chair
Rep. Richard Roy, Co-Chair
Sen. Andrew Maynard, Vice-Chair
Rep. Phillip Miller, Vice-Chair
Sen. Andrew Roraback, Ranking Member
Rep. Clark Chapin, Ranking Member

Environment Committee
Room 3200 Legislative Office Building
Hartford, CT 06106

Re: Report to the General Assembly Regarding the 2012 Integrated Resource Plan pursuant to section 16a-3a of the General Statutes of Connecticut and as amended by Public Act 11-80.

Dear Chairs and Ranking Members:

In compliance with the requirements of section 16a-3a of the 2012 Supplement to the General Statutes of Connecticut and as amended by sections 89 and 90 of Public Act 11-80, An Act Concerning the Establishment of the Department of Energy and Environmental Protection and Planning for Connecticut's Energy Future, the Department of Energy and Environmental Protection (DEEP) submits the 2012 Integrated Resource Plan (IRP).

DEEP is pleased to present this 2012 IRP as part of its mission to develop and implement energy resource strategies that will ensure that electricity in Connecticut is affordable, clean, and reliable. The 2012 IRP reflects the hard work of many people throughout the Department and the valuable input of the Connecticut Energy Advisory Board, the electric distribution companies, the Office of Consumer Counsel, and many stakeholders.

The 2012 IRP provides an in-depth assessment of the state's energy and capacity resources. It then sets forth a plan for meeting projected demand and lowering the cost of electricity by utilizing a mix of generating facilities and efficiency programs. The IRP presents numerous opportunities to continue to improve Connecticut's energy profile, and provides strategies to meet the needs of end-users in a cost effective manner, while maximizing consumer benefits and advancing the state's environmental goals and standards.

If you have any questions regarding the enclosed report please contact me or my legislative liaison, Robert LaFrance, at 860-424-3401.

Sincerely,

Daniel C. Esty
Commissioner

cc: State Librarian, Office of Legislative Research, Clerks of the House & Senate

Pursuant to Connecticut General Statutes section 16a-3a, I hereby approve this "2012 Integrated Resources Plan for Connecticut." The effective date of this 2012 Integrated Resources Plan shall be June 14, 2012.

Daniel C. Esty
Commissioner
Department of Energy and Environmental Protection

Approved: June 14, 2012

EXECUTIVE SUMMARY

The 2012 Integrated Resource Plan (IRP) for Connecticut presents a comprehensive plan for improving Connecticut's electric energy future. The 2012 IRP is the fourth for Connecticut and the first developed by the Department of Energy and Environmental Protection (DEEP), pursuant to section 16-3a of the Connecticut General Statutes. Based on analyses of projected future electricity supply and demand, the 2012 IRP outlines a plan for securing resources to meet the state's energy needs in a way that will minimize the cost to Connecticut customers over time and maximize consumer benefits consistent with the state's environmental goals and standards. The strategies identified in the IRP will help to make electricity cheaper, cleaner, and more reliable, while supporting in-state employment.

Forecast for Future Electricity Supply and Demand

- **Connecticut's electricity consumption declined sharply during the economic recession, and is not expected to exceed 2005 levels until 2022.** Over the next several years, consumption is expected to grow at approximately 1% per year. Slightly higher growth rates are expected for the annual peak load (the electricity demanded during the hour with the highest total demand).

- **Adequate generating resources will likely be available in Connecticut to serve electricity loads reliably through 2022.** New England as a whole also will have adequate resources and likely not need new generation until 2022, though depending on market conditions new generation could be needed as early as 2018. These findings are based on reasonable assumptions about market conditions, the completion of planned transmission projects, and generation retirements that are likely to occur given compliance with stricter rules for air emissions being promulgated by the U.S. Environmental Protection Agency (EPA).

- **The deliverability of natural gas fuel to electric generators requires monitoring to assure the reliability of electricity supply.** The regional power supply has become quite dependent on natural gas-fired generation, but most of those generators rely on "as-available" non-firm pipeline capacity for natural gas delivery. The amount of non-natural gas capacity plus natural gas-fired capacity currently identified as having either firm pipeline capacity or dual-fuel capability appears to be sufficient to meet winter electric demand (when competing space-heating demands for natural gas are greatest), but additional verification of back-up fuel supplies and analysis of wintertime operational challenges may be necessary to assure continued reliability.

- **Connecticut is beginning to experience lower Generation Service Charges, and can expect the downward trend to continue over the next five years.** After several years of Generation Service Charges being 10-12 ¢/kWh, those charges should now remain at or below 8 ¢/kWh through 2017 (in constant 2012 dollars) due to moderate wholesale natural gas and power prices caused by expanding shale gas supplies.

- **Between 2017 and 2022, Generation Service Charges are projected to rise by more than 3 ¢/kWh in real terms**, due to a combination of rising capacity prices (due to region-wide demand growth), rising energy prices (mostly due to expected natural gas price increases), rising Class 1 Renewable Portfolio Standards (RPS) targets and higher renewable energy credit prices (due to anticipated scarcity). Rates in 2022 could turn out to be higher or lower depending on market conditions, but are still expected to increase from projected 2017 levels.

- **Air pollution emissions in Connecticut have decreased, as low-cost natural gas-fired generation is displacing coal and oil-fired generation.** 2010 emissions of NOx, SO_2, and CO_2, fell 36%, 70%, and 10%, respectively, from 2007 levels, and they are projected to fall another 49%, 45%, and 12% by 2015. New England emissions likewise will fall from 2010 levels until 2015. Thereafter, emissions in New England and Connecticut will rise very slowly as electricity demand grows, but remain below 2010 levels through 2022.

- **A gap between projected available renewable generation and demand mandated by Connecticut's and other New England states' renewable generation targets is expected to emerge in 2018.** Connecticut has the highest target for renewable generation (20% by 2020) of all New England states, but few native resources apart from a set of in-state projects that depend on special state-sponsored contracts. Connecticut load-serving entities satisfy these renewable requirements mostly by purchasing renewable energy credits generated elsewhere in New England, competing with other states in a regional renewable energy credit market. Unless regional development of renewable resources and enabling transmission accelerates, Connecticut customers could face Alternative Compliance Payment obligations of more than $250 million (in 2012 dollars) annually by 2022. Addressing this potential burden represents an important policy priority.

Plan for Achieving Cheaper, Cleaner, More Reliable Energy Sources

The downward rate trend for the next five years provides policy makers an opportunity to put into place long-term policy measures that will alleviate expected rate increases from 2017 to 2022. The 2012 IRP identifies a plan consisting of several resource strategies that will help customers reduce the volume of consumption and, thus, save money when market-wide cost factors pressure rates; facilitate the development of low-cost, clean energy resources that are economic but may face barriers to implementation; find cost-effective ways to meet the clean energy objectives of the renewable targets; and support in-state jobs. Those strategies are as follows:

1. **Expand Energy Efficiency to Attain All Cost-Effective Energy Savings**. Based on the 2010 study of Connecticut's energy efficiency potential commissioned by the state's Energy Conservation Management Board (now the Energy Efficiency Board), the IRP concludes that the state can cost-effectively achieve approximately 2% energy savings each year, reducing energy consumption by 0.4% per year on net if the economy grows as expected. These savings can be achieved by increasing the budget for

Conservation and Load Management (C&LM) programs from $105 million annually under a business-as-usual budget to $206 million annually, and by initiating complementary measures such as providing low-cost financing, implementing more aggressive codes and standards, and motivating behavioral changes through information and training.

Net of all program and participant costs, customers would save $534 million per year by 2022 compared to a business-as-usual base case. The savings arise from reduced consumption of energy, capacity, and renewable credits, and also from reductions in market prices resulting from expanding this low-cost resource. The expanded efficiency programs and associated customer savings would support an additional 5,500 in-state jobs by 2022; cause projected air emissions to decline between 5% and 10%; and help make Connecticut a national leader in innovative approaches to achieving cost-effective energy efficiency.

2. **Analyze Renewable Portfolio Standard Issues and Develop Longer Term Renewable Energy Policy.** In accordance with Section 129 of Public Act 11-80, DEEP will prepare an analysis of RPS issues, including progress in reaching the targets and options for minimizing cost to ratepayers, and develop a longer-term renewable energy policy over the next six months. Careful monitoring of the overall progress will be important to ensure that efforts to meet the Class I Renewable Portfolio Standards do not unnecessarily increase customer costs.

   As part of this analysis, DEEP will evaluate potential policy revisions to restore incentives for combined heat and power resources and remove utility-based energy efficiency programs from Class III qualification. Since utility-based energy efficiency programs are funded through the Conservation and Load Management program, the Class III Renewable Portfolio Standard should be revised to focus primarily on providing incentives to combined heat and power and third-party energy efficiency programs that do not have a dedicated source of funding.

   DEEP will also analyze whether the RPS provides sufficient incentives for Class II generators, or if other options such as purchase power arrangements are necessary to ensure the continued operation of in-state resource recovery facilities. Over the past few years energy revenues have declined significantly creating hardship for some in-state resource recovery facilities. In addition, Class II REC prices are low and RECs may go unsold due to an over-supply. DEEP believes it is critical to examine the issues facing in resource recovery facilities to develop a long-term plan to put them in a position to continue operations on a competitive basis.

3. **Pursue Existing Opportunities to Maximize Cost-Effective Renewables.** DEEP will continue to work with other New England states (through the New England State Committee on Electricity process) to define the most cost-effective means to expand renewable energy development in the region. Connecticut's renewable energy percentage targets may be met by planning

and developing cost-effective transmission to interconnect and integrate regional renewable resources, and by maximizing the use of cost-effective in-state resources. DEEP supports efforts to drive down the cost of technologies that can best be deployed within Connecticut, such as solar photo voltaic systems and fuel cells. In addition, DEEP supports removing barriers and considering options to maximize the development of other in-state renewable energy resources. Moving forward, if cost-effective renewable resources and associated transmission projects do not sufficiently develop in New England, or if customers pay large amounts of Alternative Compliance Payments without achieving the Renewable Portfolio Standard objectives, then DEEP would consider other methods to reduce air emissions from the power sector by further increasing the investments in other clean energy or efficiency resources.

In addition to these long-term resource strategies, DEEP will continue to examine critical reliability issues and to collaborate with regional entities on solving them. These activities will include:

4. **Periodically Review Adequacy of Local Resource Supplies for Providing Reliable Generation Service during Peak Demand Periods.** Although the IRP identified no likely resource need in the near-term, DEEP will continue to monitor resource supplies, including the retirement of existing generation, the effect of energy efficiency on electricity demand, and the progress of the NEEWS transmission project. DEEP will also work with ISO-NE to ensure that its market structures provide proper incentives to retain and develop new resources when and where needed.
5. **Maintain Reliability During Winter Cold Snaps.** DEEP will work with ISO-NE to maintain reliability during winter cold snaps, when natural gas availability for generation is lowest. To ensure preparedness with backup fuels, PURA should assess the compliance of Connecticut generators with their siting requirements and contractual obligations regarding fuel capabilities.
6. **Facilitate Deployment and Funding of Microgrid and Smart Grid Technology.** Pursuant to Governor Malloy's Two Storm Panel Review and ongoing efforts for Connecticut to address storm disaster preparedness and recovery, DEEP will undertake a pilot program for the deployment and funding of distributed generation and microgrids, combined with smart grid technology at critical facilities (such as hospitals, prisons, and sewage treatment plants) and in city centers, as well as the use of energy improvement districts as a mechanism to support microgrids.

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2012 INTEGRATED RESOURCE PLAN FOR CONNECTICUT

I. INTRODUCTION

A. Purpose

The 2012 Integrated Resource Plan (IRP) for Connecticut presents a comprehensive plan for improving Connecticut's electric energy future. The 2012 IRP is the fourth for Connecticut and the first developed by the Department of Energy and Environmental Protection (DEEP), pursuant to section 16-3a of the Connecticut General Statutes. Based on analyses of projected future electricity supply and demand, the 2012 IRP outlines a plan for securing energy resources that will minimize the cost to Connecticut customers over time and maximize consumer benefits consistent with the state's environmental goals and standards. The strategies identified in the IRP will help to make electricity cheaper, cleaner, and more reliable, while supporting in-state employment.

B. Statutory Authority

Pursuant to section 16a-3a of the 2012 Supplement to the General Statutes of Connecticut and as amended by sections 89 and 90 of Public Act 11-80, An Act Concerning the Establishment of the Department of Energy and Environmental Protection and Planning for Connecticut's Energy Future (Act), the Commissioner of the Department of Energy and Environmental Protection (DEEP) is charged with reviewing the state's energy and capacity resource assessment every two years, and developing an Integrated Resource Plan that identifies how best to meet projected demand and lower the cost of electricity, utilizing a mix of generating facilities and efficiency programs while minimizing costs to customers, maximizing consumer benefits, and advancing the state's environmental goals and standards.[1] The resource needs identified in the IRP must first be met through all available cost-effective conservation and load management measures.[2]

In accordance with the Act, the Department, in consultation with the Connecticut Energy Advisory Board and the electric distribution companies, developed the 2012 IRP to assesses: (1) the state's energy and capacity resource outlook for the next three, five, and ten years; (2) the manner of how best to eliminate growth in electric demand; (3) how best to level electric demand in the state by reducing peak demand and shifting demand to off-peak periods; (4) the impact of current and projected environmental standards, including but not limited to, those related to greenhouse gas emissions and the federal Clean Air Act goals and how different resources could help achieve those standards; (5) energy security and economic risks associated with potential energy resources; and (6) the estimated lifetime cost and availability of potential energy resources. The 2012 IRP articulates a vision contemplated in the Act for improving Connecticut's energy future, and identifies a set of resource strategies that together will ensure that electricity in Connecticut is affordable, clean, and reliable.

[1] *See* 2012 Supplement to the General Statutes of Connecticut, Section 16a-3a(a).
[2] *Id.* at § 16a-3a(c).

Additionally, in developing the IRP, the Department has addressed policies and plans that are governed by other statutory mandates. The Department is required under Section 33(d)(1) of the Act to approve, modify or reject any comprehensive Conservation and Load Management (C&LM) plan submitted by the Energy Efficiency Board (EEB) under that section. The 2012 C&LM Plan submitted by the EEB recommended an ambitious expansion of the C&LM programs that incorporates additional investment in, and savings from, programs related to electricity, natural gas, and fuel oil. In a December 23, 2011 Notice of Request for Comments and Technical Meeting, the Department stated that as part of its implementation of Section 33(d)(1) of the Act, it will consider the expanded electric program within the context of the IRP.

The IRP also addresses in part the requirements of Section 129 of the Act, which directs the Department to analyze options for minimizing the cost to ratepayers of procuring renewable resources, and the feasibility of increasing the renewable energy portfolio standards (including consideration of expanding the definition of Class I renewable energy sources to include hydropower and other technologies that do not use nuclear or fossil fuels). As relevant to the Section 129 requirement, the 2012 IRP includes an analysis of alternative energy scenarios for the years 2012-2022, that model the annual percentage of renewable resources in a way that will reduce ratepayer costs, increase environmental benefits, and improve the state's economic activity. In the coming months, the Department expects to further evaluate the options for modifying the renewable energy portfolio standards in order to minimize the cost of renewable resource procurement and maximize its benefit to the state's economy.

As shown in Appendix B, Resource Adequacy, the Department evaluated the total amount of energy and capacity resources needed for customer requirements, the extent to which C&LM activity can cost-effectively meet these needs on an equitable basis, and whether new generation, transmission, and distribution improvements are needed.

C. Procedural Development of the 2012 IRP

The Department developed the 2012 IRP with analytical assistance from The Brattle Group, an economic consulting firm. DEEP staff met regularly with subject area experts from other state agencies, the EDCs, natural gas distribution companies, and The Brattle Group, to address issues related to resource adequacy and electricity market modeling, energy efficiency, renewables, natural gas, environmental issues, transmission, emerging technology, and macroeconomic analysis.

On September 19, 20, and 22, 2011, the Department conducted a series of meetings to obtain stakeholder feedback on the scope of the IRP during the development of the draft. A total of 14 presentations were given over the three-day period covering major topic areas including: Energy Efficiency, Renewables, Natural Gas, Transmission, Environmental and Emerging Technologies. Presenters included DEEP staff, the Connecticut Energy Efficiency Board, Celtic Energy, Lantern Energy, ISO-NE, Tennessee Gas Pipeline, Iroquois Gas Transmission Systems, Environmental Energy Solutions, Connecticut Energy Advisory Board, Quantum Utility Generation, Alteris Renewables, Connecticut Center for Advanced Technology, Inc. and New England States Committee on Electricity. Subsequent to the initial stakeholder meetings, written comments were submitted by Environment Northeast (ENE), New England Power Generators Association, Inc. (NEPGA), Kimberley-Clark Corporation, and NRG Energy, Inc (NRG).

A draft of the IRP was issued by the Department on January 20, 2012, together with a notice inviting written comments over a 45-day period. The Department conducted a technical meeting on February 1, 2012 at its offices at Ten Franklin Square, New Britain, Connecticut, to present the 2012 draft IRP and receive public comment. The technical meeting continued on Wednesday, February 1, 2012, at 1:00 p.m. dedicated to the expanded electric C&LM program proposed in the draft IRP. On March 2, 2012, DEEP conducted a public hearing in accordance with the requirements of Chapter 54 of the General Statutes of Connecticut, to enable the public to comment on the draft IRP and the expanded electric C&LM program. Written comments submitted on the 2012 IRP, and recordings of the February 1 and March 2, 2012 technical meeting are all available on the DEEP website.[3]

The Department received 28 written comments on the draft IRP, representing the views of the following entities: Woodlands Coalition, Environmental Energy Solutions (EES), Sierra Club, Connecticut Fund for the Environment (CFE), AARP Connecticut, Clean Water Action, Connecticut Industrial Energy Consumers (CIEC), Connecticut Business and Industrial Association (CBIA), Connecticut Energy and Advisory Board (CEAB), the Connecticut Light & Power Company/Yankee Gas (CL&P), Class III CHP Organization, Eastern Connecticut State University (ECSU), CPV Towantic, LLC, Connecticut Siting Council (CSC), ENE, Northeast Energy Efficiency Partnerships (NEEP), NEPGA, the Office of Consumer Counsel (OCC), the United Illuminating Company (UI), NRG, United Technologies Corporation Power (UTC Power), Renewable Energy New England (RENEW) and the Conservation Law Foundation, Clearedge Power, Inc., Coalition for Renewable Natural Gas, Inc., Constellation Energy Commodities Group, Inc. and Constellation NewEnergy, Inc. (CNE), Naugatuck Energy Development, LLC and a letter from concerned citizens signed by approximately 500 Connecticut residents.

The written comments focused on four key issues: the expanded savings scenario proposed by the EDCs and EEB in the C&LM Plan; the need for flexibility in regard to the states renewable portfolio standard (RPS) requirements; transmission; the need for increased generation, including combined heat and power (CHP), and repowering of certain generation assets. Some comments also addressed the forecast assumptions used in IRP. A summary of the comments and the Department's responses thereto are attached herein as Appendix J.

II. THE ELECTRICITY SECTOR AND THE SCOPE OF THE 2012 IRP

The purpose of the IRP is to identify resource strategies that can be implemented by the State to make electricity cheaper, cleaner, and more reliable. To that end, it is it is critical to recognize the kinds of resource strategies that are within the state's jurisdictional control, within the current regulatory and market context.

With the restructuring of Connecticut's electricity sector in 1998, the state does not directly determine how electricity is generated or transmitted, and it does not set prices charged for generation or transmission services. Electricity is generated by independent power producers and sold to customers via the electric distribution companies (EDCs) or competitive retail

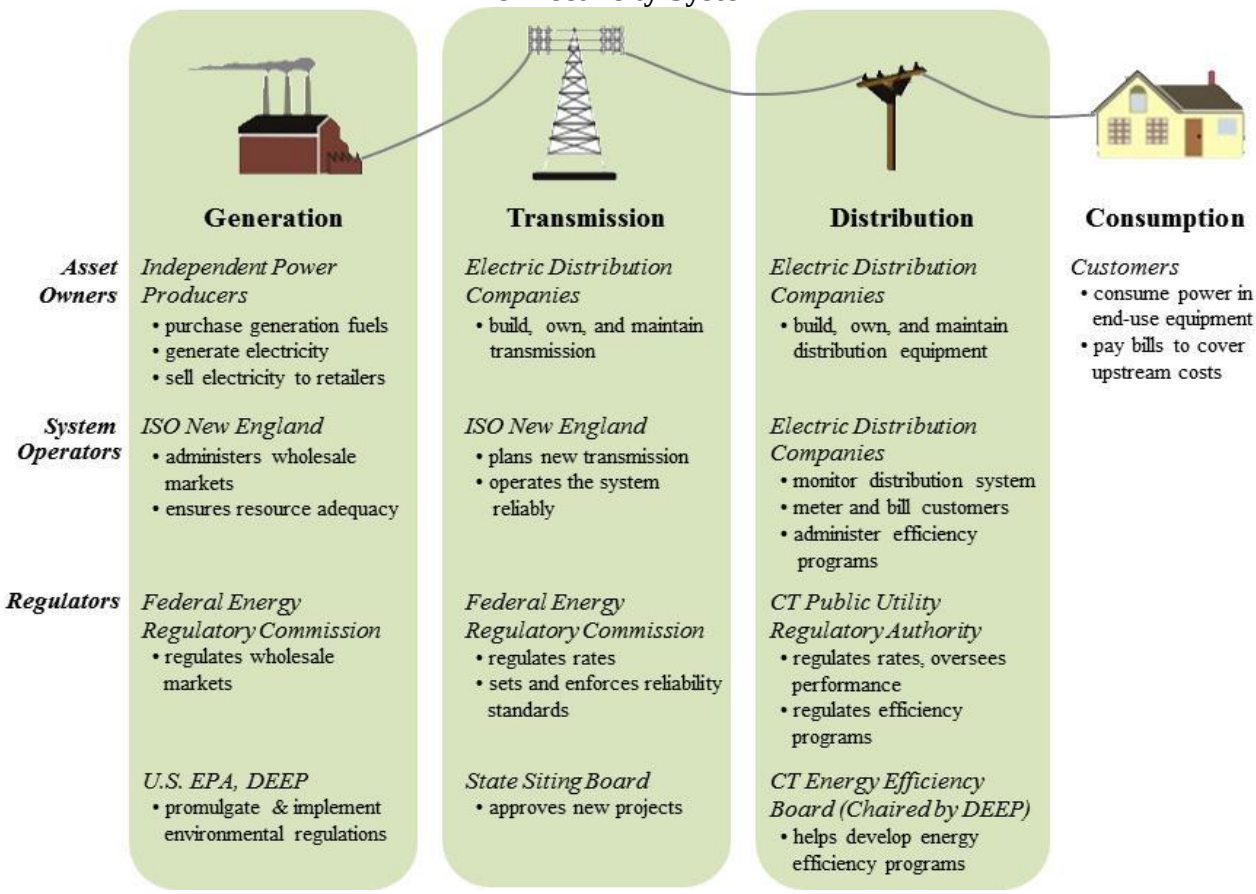
[3] Written comments and technical meeting recording are available at http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=1&Count=30&Expand=2.3&Seq=4.

providers at market-based prices. The wholesale market and the transmission system are administered by the New England Independent System Operator (ISO-NE) and regulated by the Federal Energy Regulatory Commission (FERC). Together, ISO-NE and FERC provide for open transmission access so that the lowest-cost available resources can be utilized (subject to transmission constraints), and ensure that market price outcomes are competitive.

The state's role focuses on overseeing energy efficiency programs, regulating the distribution system, implementing environmental policies, setting renewable targets on the types of supply purchased by retailers, occasionally soliciting contracts for particular generation resources on behalf of all customers, and engaging with ISO-NE in the development of market rules and in transmission planning processes.

Figure 1 shows a picture of the electricity system and describes the primary players that influence each component of the system: from generation to transmission to distribution to the customer. In addition to the entities depicted, there are many influential secondary players not included in the figure, such as lenders, energy traders, energy service companies, and curtailment service providers (who help customers manage their peak loads and sell load reductions as supply into the wholesale markets).

Figure 1
The Electricity System



Each of the parties identified in Figure 1 contribute in different ways to the cost, environmental impacts, and reliability (*i.e.*, resource adequacy, transmission security, and distribution resiliency) of the electricity system. Generation accounts for the largest (and most variable) portion of rates, and produces all of the emissions.[4] Market-based generation rates reflect wholesale market prices, which are largely driven by natural gas prices, regional supply-demand fundamentals, and market rules. Figure 2 describes these contributions.

Figure 2
Costs, Reliability, and Environmental Impacts of Electricity

	Generation	Transmission	Distribution
Costs/Rates			
Determinants	*Wholesale Market Conditions* • gas prices • supply-demand fundamentals *Special contract costs*	*Embedded Costs* • historic capital expenditures • cost allocation *Going Forward Costs* • new investment • operations & maintenance	*Embedded Costs* • historic capital expenditures *Going Forward Costs* • new investment • operations & maintenance
Approximate Current Rates	*9.5 ¢/kWh (varies)*	*1.8 ¢/kWh*	*5.0 ¢/kWh*
Reliability			
Criteria	*Resource Adequacy* • enough resources to meet peak loads and prevent shedding firm load more than once in ten years, with margin for forecast uncertainty and outages	*Transmission Security* • protect individual facilities and maintain the voltage and stability of the system in the face of contingencies	*Distribution Resiliency* • deliver customer power under all load conditions • storm preparedness and response
Who Enforces	*ISO New England*	*ISO New England*	*CT Public Utility Regulatory Authority*
Environment	*Air* • NOx, SOx, CO2, particulates, mercury, other *Water* • cooling water intake, discharge	*Land Use Impacts*	*Aesthetics* • overhead lines vs. underground • tree trimming

Energy efficiency programs, not shown in Figure 2, have been funded for many years primarily through a 0.3 ¢/kWh "systems benefits charge" on all customers' bills. These programs and other state policies have been ranked by the American Council for an Energy Efficient Economy (ACEEE) as the 8th best in the country, indicating success with room for improvement.

The 2012 IRP focuses primarily on resource strategies that can be implemented by the State to make electricity cheaper, cleaner, and more reliable. To that end, the IRP focuses on the state-jurisdictional areas identified above, particularly on the subset of areas that involve potential resource investments. It excludes a few important areas of state jurisdiction because they are being addressed concurrently outside of the IRP. For example, distribution resiliency and storm response are excluded because they have been the subject of investigation by the Governor's office. The procurement of wholesale power to serve customers who choose to buy generation

[4] Approximate rates shown are representative for a typical residential customer in Connecticut in 2012. The "Generation" rate includes the Generation Service Charge and charges for special contracts.

from the EDCs is also excluded because it is being addressed by Connecticut's new procurement manager in accordance with his or her authorities prescribed under the Act.

III. ANALYTICAL APPROACH

The analytical approach used to develop the 2012 IRP included the following four sequential steps:

1. Develop Base Case assumptions and a three, five, and ten-year outlook for resource needs in Connecticut and New England; certain aspects of reliability; customer rates; and emissions. Analyze the drivers of likely changes in Connecticut customer rates as a starting point for identifying improvement opportunities.

2. Analyze how outcomes could change under alternative Futures regarding market conditions the state cannot directly control, including natural gas prices, broad economic growth, and generation supply.

3. Evaluate several Resource Scenarios and policy options the state could pursue involving energy efficiency, renewable generation (including remote resources and associated transmission), and new conventional generation, to reduce costs and emissions while supporting in-state jobs. Test the robustness of Resource Scenarios against the Base Case and alternative futures. Consider ways to enable emerging technologies that may be part of a longer-term solution.

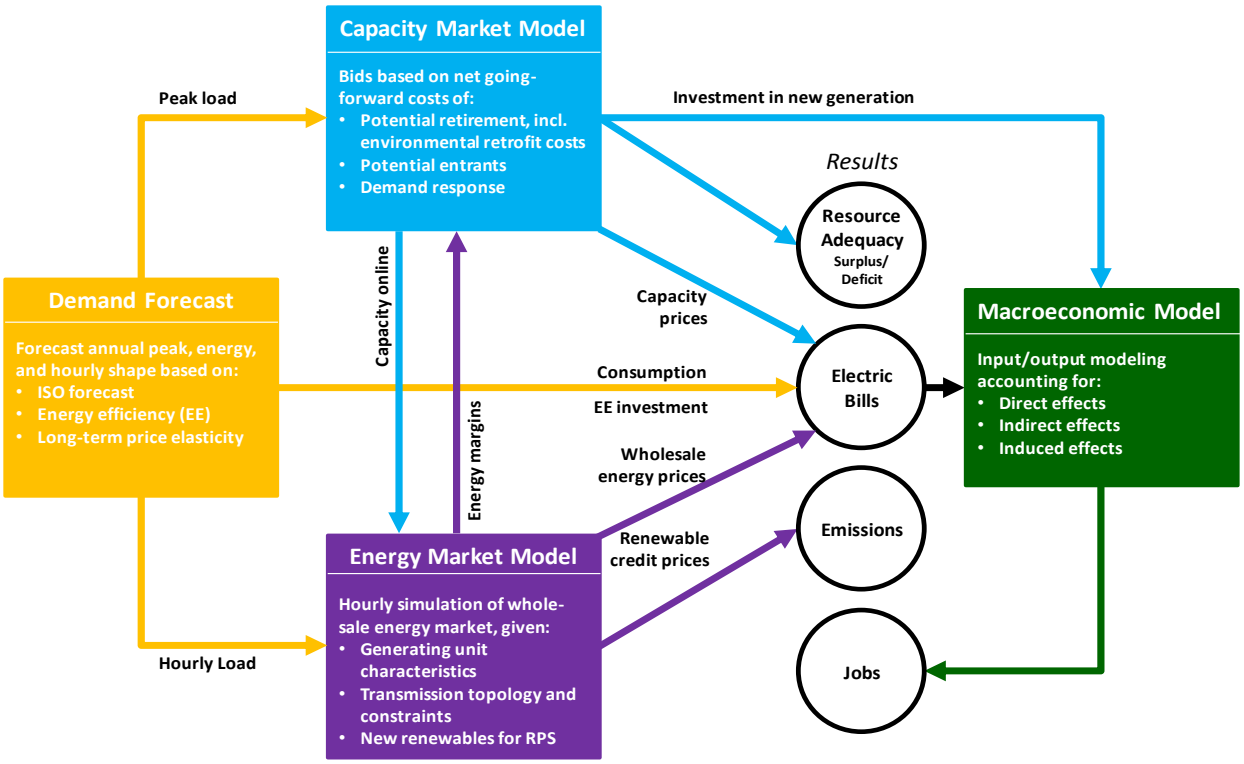
4. Develop a plan, based on the findings above.

The findings and analyses prepared in each step in the sequence are provided in Sections IV through VII of the 2012 IRP. These analyses are based on publicly available data about the Connecticut and broader New England electricity markets. Projections and impact analysis also rely on a modeling system with four major interconnected components, as depicted in Figure 3. These components include: a demand forecast; a capacity model used to simulate capacity prices in ISO-NE's Forward Capacity Market and to project new resource entry and retirement decisions; the DAYZER[5] model used to simulate ISO-NE's energy market, generator operations, and locational marginal prices (LMPs) in Connecticut, with a closely-linked renewables model to project renewable energy credit (REC) prices; and a macroeconomic model (REMI) used to analyze impacts on in-state jobs. The electricity models were developed and utilized in prior IRPs and were employed again by The Brattle Group under the Department's direction. The REMI analysis was prepared by the Connecticut Department of Economic & Community Development.

Complementing the modeling system, the Department directed extensive research and analysis of publicly available information on resource adequacy, energy efficiency, renewables, natural gas, environmental issues, transmission, and emerging technology. Detailed explanations of the various components of the analysis are provided in Appendices A through I. All dollar figures in this report are presented in 2012 dollars except where noted otherwise.

[5] DAYZER is a commercially available model developed by Cambridge Energy Solutions.

Figure 3. Schematic of the Modeling System



IV. BASE CASE TEN-YEAR OUTLOOK

A. Supply and Demand for Capacity

Because electricity cannot be stored in meaningful quantities, the electricity sector must maintain an intentional surplus of resources to be able to serve customer demand every hour. This surplus must be sufficient to serve customers even under extreme conditions, such as on the hottest summer days when demand for electricity spikes and generating units unexpectedly break down. Resources can be supplied in many different ways, including generating capacity, transmitting power from other regions, and predictably curtailing demand when needed. Various metrics are used to measure resource adequacy and to quantify expected reliability.

The base case Ten-Year outlook analyzed in this section projects that the supply of capacity resources is greater than needed to meet peak electricity load reliably over the next decade.[6]

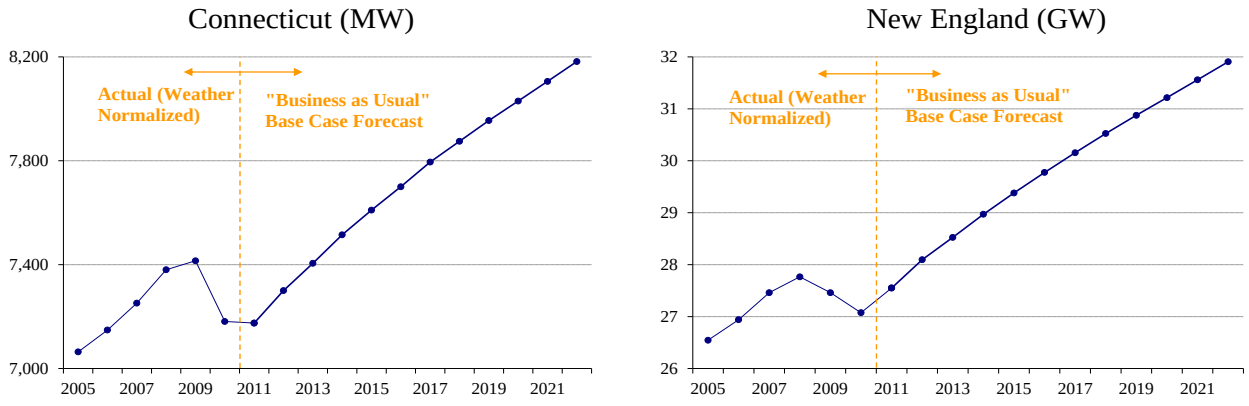
[6] "Peak load" refers to the maximum amount of power (measured in megawatts) used by customers over the course of a year. In New England, the peak load hour usually occurs during July or August. In general, "MW" refers to capacity, or power, while "megawatt-hours" (MWh) refer to energy produced or consumed. One MWh is equal to a MW of power produced or consumed over one hour. Common prefixes for both Watt and Watt-hour measures include "kilo" (k = 1,000), "mega" (M = 1,000,000), "giga" (G = 1,000,000,000) and "tera" (T = 1,000,000,000,000).

That is, resource adequacy requirements set by ISO-NE are projected to be satisfied for ten years in both the Connecticut sub-area and in the New England region as a whole. This projection is attributable to several factors: (1) the region has an existing capacity surplus of more than five thousand megawatts; (2) demand growth is forecasted to be slow, partly due to the current economic conditions and partly because of continued utility energy efficiency programs and new codes and standards; (3) new transmission into Connecticut is helping to meet local adequacy requirements; and (4) the current capacity surplus is large enough to withstand the effect of likely generation retirements resulting from the implementation of EPA's proposed Air Toxics rule in 2015-2016 and the planned elimination of the capacity price floor in 2017-2018.[7] Thus, additional generating resources will not be needed for resource adequacy purposes. New generating resources may be needed, however, to serve other policy objectives, including reducing costs and emissions and supporting in-state jobs. These scenarios are discussed in later sections of the 2012 IRP.

Peak Load Forecast

Peak load in Connecticut declined during the recent economic recession, as demonstrated in Figure 4. ISO-NE forecasts an annual growth rate of 1.7% (125 MW/year) over the next few years, decreasing to 0.9% (75 MW/year) by 2020. The New England system peak load is forecast to grow at an annual rate of 2.0% initially (545 MW/year), decreasing to 1.1% growth (340 MW/year) by 2020, as shown in Figure 4.[8] These peak load projections do not deduct the effects of energy efficiency, most of which is counted separately as a supply-side resource in ISO-NE's Forward Capacity Market and in the supply-demand projections in the 2012 IRP.[9]

Figure 4
Peak Load — Historical and Forecast



7 These and related factors are described in more detail below and in Appendix B (Resource Adequacy).

8 The Connecticut 2010 peak value is a Brattle Group estimate based on data from ISO-NE.

9 These are ISO-NE's "gross" forecasts, before accounting for demand-side resources that have cleared in forward capacity auctions. However, as discussed in Appendix B (Resource Adequacy), these forecasts do implicitly include some level of business-as-usual efficiency improvement.

Connecticut and New England Reliability Requirements

ISO-NE has established several resource adequacy requirements that affect Connecticut.

- **Connecticut Local Sourcing Requirement.** ISO-NE defines two requirements for local capacity in Connecticut: the Local Resource Adequacy requirement and the Connecticut requirement under the Transmission Security Analysis.[10] Whichever requirement is more stringent determines the local requirement. Because the capacity required under the Transmission Security Analysis has historically been greater than the capacity required under the Local Resource Adequacy requirement, the 2012 IRP's resource adequacy analysis focuses on that measure.
- **Net Installed Capacity Requirement (NICR) for the New England region.** The Net Installed Capacity Requirement is the total amount of capacity needed to achieve the applicable reliability target specified in ISO-NE's Planning Procedures (and by the North American Electric Reliability Corporation) to limit the probability of disconnecting non-interruptible customers due to resource deficiency to no more than once in ten years. The Net Installed Capacity Requirement also sets the total demand for capacity in ISO-NE's forward capacity auctions. Notably, ISO-NE has recently changed the methodology for determining the requirement, which has increased the Net Installed Capacity Requirement from 11.4% above forecast peak load to 14.4% above peak. This change represents an increase of approximately 1,000 MW. This higher required reserve margin will tend to increase capacity costs and reduce energy costs.
- **Connecticut Locational Forward Reserve Market Requirement**. This requirement ensures enough quick-start capacity within Connecticut to recover from a second contingency occurring in Connecticut. Commonly, the second contingency protection for this market requirement is an unexpected outage of the Millstone 3 nuclear unit.

Existing, Planned, and Assumed Future Resources

To analyze compliance with the Net Installed Capacity Requirement and Connecticut reliability requirements, the Department first considered "known" generating and demand-side resources, i.e., those that already exist or new resources expected to be online, based on currently available information:

- *Existing Generating Capacity.* As of January 1, 2011, there are 8,150 MW available in the Connecticut sub-area and 32,027 MW available region-wide to meet reliability requirements.[11]
- *Planned Additions*. Planned additions fall into two categories: capacity built to help satisfy Renewable Portfolio Standards (RPS) and capacity built for

[10] See http://www.iso-ne.com/genrtion_resrcs/reports/nepool_oc_review/2011/ icr_2014_2015_final_report.pdf

[11] Capacity online is documented in the ISO-NE "2011-2020 Forecast Report of Capacity, Energy, Loads and Transmission" (2011 CELT Report).

other reasons. The latter, non-RPS Planned Additions include the 130 MW New Haven Harbor gas turbine plant scheduled to come online on June 1, 2012 and an 88 MW expansion to Northfield Mountain pump-storage plant in Massachusetts scheduled to be completed by Summer 2015. Planned additions to satisfy RPS requirements are 46 MW (46 MW capacity value) in Connecticut and 170 MW (69 MW capacity value) region-wide.[12] These include projects being developed for Project 150 in Connecticut as well as additional onshore wind and solar PV that are currently being developed or have announced plans to build. In addition, the Department assumes 343 MW (150 MW capacity value) of renewables that are not yet planned will be developed in Connecticut and 2,470 MW (766 MW capacity value) region-wide to help meet RPS requirements, as discussed in the "Outlook for Renewable Generation Supply and Demand" section below.

- *Retirements*. Based on publicly available information and third-party data, the Department assumes the retirement of 183 MW in Connecticut (AES Thames) and 1,366 MW in the rest of New England (Salem Harbor, Vermont Yankee, Holyoke 8/Cabot 8, and Holyoke 6/Cabot 6). Additional economic retirements are discussed below.
- *Demand Resources*. Demand resources include active demand response, and passive demand response. "Active demand response" is the ability to reduce participating customers' loads when called upon by ISO-NE if committed generating resources are insufficient to meet the peak demands. Curtailment service providers sell these so-called active demand response "negawatts" into the forward capacity auctions. "Passive demand response" primarily covers energy efficiency. Both active and passive demand response resources are treated as supply resources in the Forward Capacity Market. For the 2012 IRP analysis, the Department counted all demand response resources committed in the forward capacity auction for delivery year 2014/2015, but limited real-time emergency generation (RTEG) to 600 MW in accordance with ISO rules. Active demand response clearing in that forward capacity auction totaled 1,982 MW region-wide and 521 MW in the Connecticut sub-area. Passive demand response clearing in that auction will provide 1,486 MW region-wide, including 419 MW in Connecticut.
- *Net Imports*. Net imports into New England are assumed to be constant at 1,911 MW for years 2015 through 2022, consistent with amounts cleared in ISO-NE's first five forward capacity auctions. This reflects 2,011 MW of imports and 100 MW of exports.

Projected Economic Retirement, Entry, and Active Demand Response

The analysis conducted by the Brattle Group recognizes that, in the market context, many key outcomes cannot be ensured or planned, but instead will be determined by the decisions of

[12] Divergence between equipment capacity ratings and capacity values assigned by ISO-NE in resource adequacy analysis occurs because some resources (*e.g.*, solar and wind) frequently are not fully available during peak hours.

market participants, and therefore can only be projected. Projecting market participants' potential entry (in the form of new generation or additional demand response resources) and exit (in the form of retirement of generation or attrition of demand response) requires modeling of their financial decisions, which are based primarily on likely market prices and the ongoing costs of providing the capacity service. The Brattle Group's capacity market model simulates ISO-NE's forward capacity auctions and economic entry and exit decisions simultaneously, since the capacity prices influence individual economic decisions *and* reflect the combined results of those decisions. In the model, the annual demand for capacity is provided by the Net Installed Capacity Requirement projections; supply includes most existing and planned generation bidding as price takers (offering capacity at zero price and accept whatever price results), while potential retirement candidates, active demand response resources, and potential new entrants submit bids that reflect their net avoidable going-forward costs. The marginal capacity needed to meet the requirement sets the equilibrium capacity market price. Resources that offer capacity at a higher price than the market price (i.e., resources do not "clear" the auction) either retire or do not enter.[13]

The model results indicate that the Connecticut capacity price would not separate (differ) from the New England capacity price if the New England East-West Solution (NEEWS) transmission project, scheduled for completion in 2016, continues to be developed and receives the necessary approvals. This would allow Connecticut to meet its Transmission Security Analysis requirement even if all fossil steam units in Connecticut retired. However, there would be price separation in the Northeast Massachusetts/Boston area starting in 2016. The Department assumed that this need would be met by incremental energy efficiency (an amount that is less than that called for by the Massachusetts Green Communities Act), although ISO-NE is considering a proposal to meet this need with new transmission.

Generation retirement decisions are driven largely by capacity market prices and evolving environmental regulations, specifically regulations that control hazardous air pollutants (HAPs) such as mercury. The analysis assumes these regulations will require generators without certain pollution controls to install costly retrofits (Maximum Achievable Control Technology, or MACT) or retire in 2015. The U.S. EPA has also proposed many other regulations that will affect generators, but none of these yet clearly impose widespread, inflexible requirements for retrofits and compliance on par with the rule that controls hazardous air pollutant emissions. The Cross-State Air Pollution Rule (CSAPR), which was stayed in December 2011 pending judicial review, would exempt Connecticut and Massachusetts and, in any case, would impose allowance costs, not stringent control requirements. The EPA's plan to tighten ozone standards, which could lead to strict emissions rate limits, has been delayed and will likely not have a significant impact until the end of the 10-year study horizon. The proposed rules under the Clean Water Act Section 316(b) on cooling water intake structures appear to have flexible compliance mechanisms, and confer implementation discretion on states.

In order to determine which generation units would have to install specific controls to comply with Maximum Achievable Control Technology requirements for hazardous air pollutants, DEEP consulted with Connecticut generation owners and environmental agencies from other

[13] The forward capacity auctions have so far had a price floor that has determined the price in surplus conditions. This price floor will expire in the 2016/17 forward auction, which will be conducted in 2013.

states.[14] The Brattle Group analysis assumes that an electrostatic precipitator (ESP) would likely be needed on Middletown 4 and Montville 6 in Connecticut, and Yarmouth 1-3 in Maine to capture mercury emissions.[15] It further assumes the Schiller coal plant in New Hampshire and the Mt. Tom coal plant in Massachusetts would likely need activated carbon injection (ACI) to improve the effectiveness of their fabric filters or ESPs in capturing mercury. The Brattle analysis also assumes that the Bridgeport Harbor 3 coal unit would need dry sorbent injection (DSI) to control acid gases, as would the Schiller coal plant in New Hampshire. The capital costs of such retrofits range from $12/kW to $226/kW, as documented in Appendix E (Environmental Regulations).

The capacity model evaluates the economic implications of retiring versus retrofitting each unit by comparing the sum of retrofit costs and ongoing fixed operations and maintenance costs to the short term (3 year) net present value of energy margins and capacity revenues expected from continued operation. Energy margins are estimated in the DAYZER model, and capacity prices are estimated within the capacity model. The result was 1,687 MW of economic retirements regionally (in addition to the 1,549 MW already planning to retire) mostly occurring in 2015, the assumed compliance deadline for hazardous air pollution rules. In Connecticut, there would be 938 MW of economic retirements in 2015, in addition to 183 MW already planned. However, many of the old steam units in Connecticut that are not projected to need capital-intensive controls to comply with the hazardous air pollution rules would likely remain online because their going-forward fixed operations and maintenance costs are less than the projected capacity price. These units include the Middletown 2-3, Montville 5, New Haven Harbor and Norwalk Harbor 1-2 steam oil units. The Bridgeport Harbor 3 coal unit is projected to remain online despite the cost of installing dry sorbent injection.

The amount of active demand response in the market also requires estimation because market participants decide how much to provide largely based on capacity prices. Intuitively, one would expect that supply of active demand response would decrease when capacity prices fall (e.g., after the price floor is eliminated) and increase when they subsequently rise. For forecasting purposes, The Brattle Group constructed an active demand response supply curve with a fixed cost component, and a variable cost component (per MWh of expected interruption) that increases as total market demand response penetration increases to account for a greater probability of being called. Including this supply curve in the capacity market simulations caused projected active demand response to decrease from 1,982 MW already cleared in the fifth capacity auction for 2014/15 to 1,006 MW when the price floor is eliminated; projected active demand response would then rise to 2,588 MW in 2022 when capacity prices are expected to be substantially higher.

New generation entry is assumed to occur only when the capacity price rises to the Net Cost of New Entry (Net CONE) of the most economic generation technology in New England: a gas-fired combined-cycle plant. The Net Cost of New Entry of a new combined-cycle plant is

[14] These estimates are only intended for the purpose of this analysis, not as a regulatory determination of actual control requirements.

[15] An electrostatic precipitator is a device that removes dust or other finely divided particles from power plant exhaust by charging the particles inductively with an electric field, then attracting them to highly charged collector plates.

provided by the annual capital carrying charges and fixed operating and maintenance costs, minus the energy margins and ancillary services revenues it would earn, as estimated in the DAYZER model. The annual capital carrying charges and fixed operating and maintenance costs are assumed to be $138/kW-year (in 2012 dollars), based on the costs The Brattle Group recently estimated for PJM Interconnection LLC for a new combined-cycle plant in New Jersey, which are increased by 4.7% to account for higher labor costs in Connecticut.[16] At these costs, no new combined-cycle capacity would enter until 2022-2023 in the Base Case. In the meantime, other lower cost resources, such as active demand response, would be expected to meet the Net Installed Capacity Requirement and set capacity auction clearing prices.

Projections for Capacity Prices and Resource Adequacy

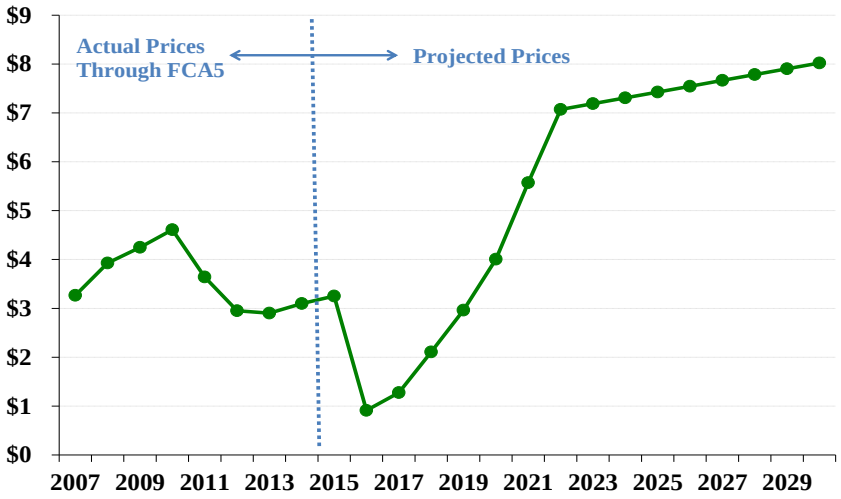
Capacity prices through 2015-2016 are given by the administratively determined price floor.,[17] After the price floor expires, DEEP expects prices to reflect the supply and demand conditions summarized above.[18] The capacity model is considered solved when the market clears, with capacity prices that are consistent with the modeled economic exit and entry decisions. Projected prices are expected to fall below $1/kW-month to clear most of the capacity surplus that the price floor was supporting. As Figure 5 shows, prices are then projected to rise as load grows and higher-cost demand response re-enters. Capacity prices become progressively higher until new generation is needed and prices reach the Net Cost of New Entry level ($7.1/kW-month) in 2022-2023.

[16] The key parameters are $929/kW overnight cost, 13.1% level-real capital charge rate (based on 8.5% merchant ATWACC and 20-year economic life), and $17/kW-yr fixed operations and maintenance costs, for a 656 MW combined cycle. These estimates are based on "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM," adjusted to account for higher labor costs in Connecticut. *See* http://www.pjm.com/~/media/committees-groups/committees/mrc/20110818/20110818-brattle-report-on-cost-of-new-entry-estimates-for-ct-and-cc-plants-in-pjm.ashx.

[17] In the analysis, capacity prices paid to generators are prorated when the price floor is binding and surplus capacity clears.

[18] At the time the analysis for the 2012 IRP was conducted, the price floor was set to expire after the auction for the 2015-2016 delivery year. Shortly after the analysis and draft report were completed, ISO-NE stakeholders voted to extend the price floor for another year, subject to FERC approval. DEEP did not incorporate that change into the IRP analysis because of time constraints. However, the likely one-year extension of the price floor is not expected to alter the regional supply fundamentally from the projections presented in the 2012 IRP. Many of the retirements are still likely to be driven by environmental requirements; other market dynamics may occur a year later than projected. In any case, the IRP projections should be considered approximate and uncertain due to the uncertainties surrounding future auction rules, environmental regulations, and market conditions.

Figure 5
Projected Capacity Prices (2012$/kW-month)



The resulting supply and demand for resources is described in detail in Appendix B (Resource Adequacy). The bottom line is that all of ISO-NE's reliability requirements affecting Connecticut can be expected to be met through 2022, without having to plan or facilitate new generation resources. These requirements are discussed in more detail below.

First, with respect to the **Connecticut Local Sourcing Requirement**, the projections indicate that there are adequate resources in Connecticut to meet the Transmission Security Analysis criteria well beyond 2022, with 600 MW of surplus in 2015-2016, and then 1,900 to 2,000 MW of surplus in 2016-2017 and beyond. The surplus is likely to remain approximately constant after the price floor is eliminated, since demand response is likely to exit initially but then return as load grows and capacity prices rise. Resources are shown as stacked bars in Figure 6, clearly exceeding the requirement shown in black. Projected retirements, shown as empty boxes at the top of the stacked bars, are not sufficient to eliminate the surplus.

It is important to point out that this projection assumes that the various components of the planned New England East-West Solution (NEEWS) transmission project will be completed. The NEEWS project is planned to address several transmission security reliability issues, and it will also support local resource adequacy in Connecticut as a side benefit. DEEP assumes that the NEEWS transmission enhancements will increase Connecticut's import capability by 1,100 MW (shown on Figure 6 as a reduction in the local requirement) and electrically incorporate the Lake Road generating facility (745 MW) into the Connecticut sub-area.

Two of the components of NEEWS—the Rhode Island Reliability Project and the Greater Springfield Reliability Project—are currently under construction. The remaining two components—the Interstate Reliability Project and the Central Connecticut Reliability Project—are not yet under construction. They were included in the IRP Base Case because they have received the required ISO-NE technical approvals. The relevant state siting boards, however, have yet to review the siting impacts and the reliability need for these components. State siting reviews will be informed by ISO-NE's forthcoming reliability assessment, which will be updated

to account for currently-projected system conditions. State siting hearings for the Interstate Reliability Project are underway in Connecticut and will be filed soon in Massachusetts and Rhode Island. State siting permit applications for the Central Connecticut project have not yet been filed.

If the Interstate and Central Connecticut projects are not approved, the Connecticut import capability would be 1,000 MW less than assumed for years 2016 through 2022 in the IRP Base Case, and the 745 MW Lake Road generating facility would not be incorporated electrically into Connecticut. Local resource adequacy would still be maintained, but with a smaller surplus of only approximately 200 MW between 2016 and 2022 (compared to 1,900-2,000 MW in the Base Case).

If, on the other hand, all components of the NEEWS project are completed as planned, Connecticut's local resource adequacy would be maintained even if all 2,716 MW of the fossil steam capacity in Connecticut retired (compared to 1,112 MW of retirements projected). Even with the completion of NEEWS, a 350 MW shortfall could occur in an unlikely scenario where: (1) all fossil steam units retire; (2) ISO-NE's "high economic growth" forecast is realized (about 350 MW higher Connecticut load by 2022 than in the Base forecast); and (3) all 400 MW of old aero-derivative combustion turbines retire due to potential future NOx regulations. Such a large number of steam and combustion turbine retirements is unlikely because these units appear to be economic under future market conditions. Even if a few more units retired than projected, capacity market prices would increase, providing additional incentive for the remaining units to stay online. Furthermore, for those potential retirements that might pose a local reliability concern, ISO-NE could resort to offering reliability must-run contracts.[19] The potential challenges from increased retirements would be greater if the Interstate and Central Connecticut Reliability Projects are not constructed.

Until the uncertainties surrounding the Interstate and Central Connecticut component of NEEWS are resolved, DEEP will continue to monitor the supply, demand, and transmission situation and assess whether any local resource adequacy shortfalls could occur. In the event of any ISO-NE determination that the Interstate and Central Connecticut portions of the NEEWS project are no longer needed, DEEP will initiate a process to determine if additional resources are needed for reliability, and will amend the IRP as appropriate.

Second, with respect to the **Locational Forward Reserve Market**, the Brattle Group's modeling shows that there are more than adequate resources projected to meet Connecticut's Locational Forward Reserve Market requirement. ISO-NE's 2011 Regional System Plan indicates that, through 2015, Southwest Connecticut will have no such requirement, while Greater Connecticut may need 400 to 1,000 MW of quick-start capacity.[20] The model projects 1,501 MW available in Greater Connecticut, including 949 MW in Southwest Connecticut, well above the projected need in each area.

[19] Such contracts may only provide a temporary solution, as their duration would have to conform to the environmental compliance deadlines.

[20] See http://www.iso-ne.com/trans/rsp/2011/index.html.

Finally, with respect to the **Net Installed Capacity Requirement for New England**, adequate resources are projected for meeting the Net Installed Capacity Requirement through 2022. As Figure 7 shows, the stacked bar depicting supply exceeds the requirement through 2015. Thereafter, without a capacity price floor to maintain surplus capacity, the forward capacity auctions clear just enough supply to meet the requirement. Generation retirements and demand response attrition are sufficient to eliminate the surplus in 2016. Re-entry of existing demand response compensates for load growth through 2020, and additional demand response meets further load growth through 2021. By 2022, new generation entry begins to become economic. These conclusions are based on our simulated generation retirements and entry by demand response providers, as discussed above.

Figure 6. Locational Resource Adequacy in Connecticut

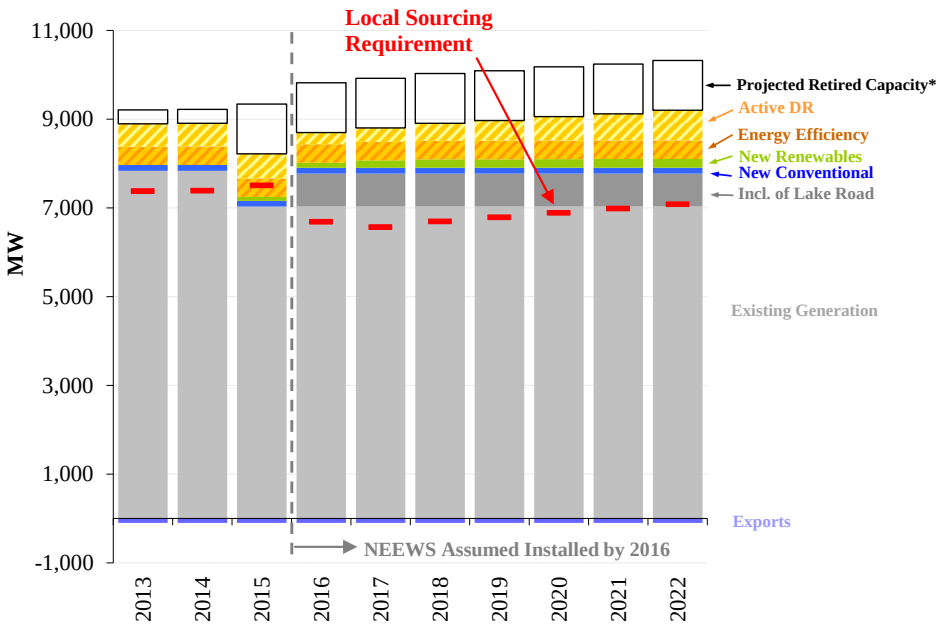
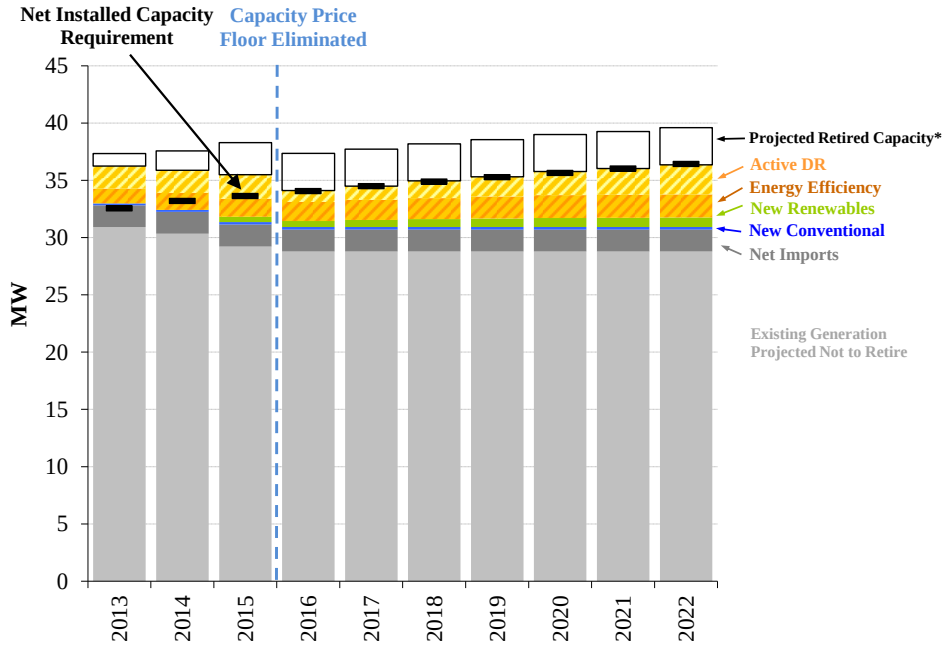


Figure 7. Resource Adequacy in New England



Even if these projections and assumptions (such as assuming regional imports remain constant at approximately 1,900 MW) turn out to be wrong, the capacity market is designed to self-correct for such "errors" and to restore a balance between resources and prices. For example, if an additional generating unit retired, capacity prices would increase, which would reduce the

incentive for any further retirements and would enhance incentives for additional demand response to enter the market.

Winter Generating Fuel Availability

There is an additional type of resource adequacy that does not correspond to any current ISO-NE requirement: preparedness for severe winter cold snaps, when there may be limited natural gas available for natural gas-fired generating units. In New England, most natural gas-fired generators lack firm gas pipeline delivery, although Mystic 8 and 9 (1,679 MW winter capacity) have their own liquefied natural gas (LNG) supply source, and over 1,600 MW of other generators currently have firm mainline gas transportation in New England.[21] An additional 5,300 MW of capacity has dual-fuel capability, yielding over 8,500 MW of natural gas-fired generators that currently have nominally reliable fuel supplies.

In the IRP Base Case energy market simulations, some level of natural gas-fired capacity is required to meet peak winter electricity loads in each of the three study years. Although a substantial amount of natural gas-fired capacity currently has dual-fuel capability or firm gas supplies, there is no requirement for generators to maintain reliable access to fuel, and thus the firmness of these fuel supplies cannot be verified or regularly tested. In addition, the "just-in-time" natural gas delivery system stresses both the natural gas system (e.g., causing pressure problems and unavailability of non-firm capacity) and the electric system (e.g., causing operational issues) during tight winter conditions.

DEEP recognizes that, for the longer term, the issue of natural gas reliance in winter warrants continued close monitoring, since a number of uncertain factors will influence the degree to which the electric system depends on natural gas-fired capacity that may lack firm fuel supplies or dual-fuel capability. These factors include retirements of oil and coal-fired generation; the extent to which natural gas units with firm fuel or dual-fuel capability maintain that capability; and the extent to which the electric system can rely on natural gas-fired generators without firm fuel supplies. This is a complex issue that requires further analysis, potentially including modeling cross-system dependencies between the electricity and gas systems to fully understand their interactions under stress conditions. ISO-NE is examining this issue under its Strategic Initiative. DEEP is monitoring the ISO-NE initiative and will engage in the ISO process as necessary. DEEP will also assess the compliance of Connecticut generators with their siting requirements and contractual obligations regarding backup fuel capabilities.

In December 2011, ISO-NE released a presentation based on a draft report assessing New England's natural gas pipeline capacity to satisfy power generation needs.[22] That presentation suggested that regional natural gas supply capability is inadequate to satisfy regional gas demands on a winter design day over the next decade. The presentation did not focus on electric reliability. For example, it did not explicitly take into consideration the substantial amount of

[21] Of this 1,655 MW with firm gas capacity, about 500 MW is in Connecticut: Lake Road (246 MW worth of firm gas), Milford Power (218 MW), and Wallingford/Pierce (35 MW).

[22] *See* "Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Power Generation Needs," presented by ICF International to ISO-NE Planning Advisory Committee, December 14th, 2011.

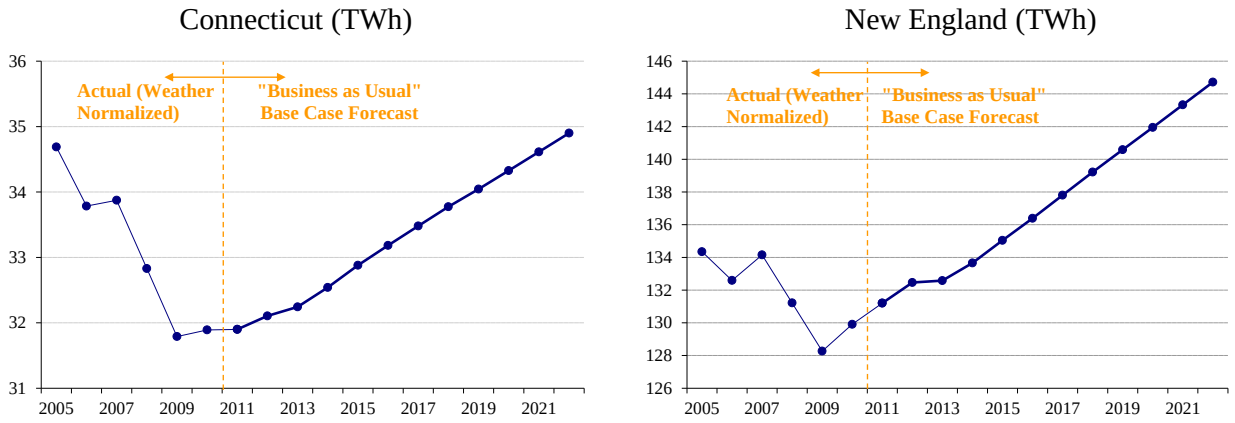
natural gas-fired capacity that is dual-fuel capable and can operate on its alternative fuel if necessary.

B. Demand and Supply of Energy

Connecticut's electric energy consumption has declined sharply since 2005 due to several factors, including the economic slowdown and continued implementation of energy efficiency measures. Looking forward, Connecticut's energy consumption is expected to grow at approximately 1% per year, not reaching 2005 levels again until 2022. The rest of the New England region has not declined as sharply and is projected to recover at 1.1% annually, as shown in Figure 8.[23]

Because DEEP's projections show that adequate capacity will be available, as discussed above, DEEP also expects that energy requirements can be met reliably. *How* energy is produced, and the wholesale price of that energy, will depend on fuel prices, the types of resources that are developed or retired in the future, and transmission constraints. For the IRP, the DAYZER market simulation model was used to analyze how energy is produced. DAYZER includes all of the key elements of energy supply and demand, as well as all existing and planned transmission facilities in the ISO-NE system.

Figure 8
Annual Energy Consumption — Historical and Forecast for CT and New England[24]



One of the most important inputs is natural gas prices, with the prices of coal, oil, and emissions allowances also influencing wholesale market outcomes to a lesser extent. Natural gas prices are based on NYMEX Henry Hub futures through 2021. The 2012 IRP relied on futures traded between 8/5/11 and 9/16/11, which were priced at $4.10/MMBtu for near-term delivery, rising to

[23] These figures are net of energy efficiency that has been implemented to date, some future energy efficiency measures that will be implemented to fulfill commitments made in ISO-NE's forward capacity auctions through 2014-2015, and some amount of energy efficiency impacts that are embedded implicitly in the forecast as a continuation of "business-as-usual" trends. There are a number of challenges to fully and accurately account for energy efficiency in the load forecast that are discussed in Appendix B (Resource Adequacy) and Appendix C (Energy Efficiency).

[24] Year 2009 and 2010 weather normalized energy consumption figures for Connecticut are estimates supplied by The Brattle Group.

$5.21 by 2015, $5.40 by 2017, and $5.92 by 2022.[25] Delivered natural gas prices also include a basis differential based on historical prices and NYMEX basis swaps ($1.06/MMBtu on average, with a January high of $3.12/MMBtu), plus a $0.30/MMBtu charge for generators served by local gas distribution companies instead of directly by a pipeline.[26] Oil prices are much higher, based on current forward prices. Coal prices, affecting approximately 2,000 MW of capacity in New England with Salem Harbor and AES Thames retired, are $4/MMBtu, which is high in historical terms. Coal prices are based on NYMEX Central Appalachian futures plus transportation costs.

Emissions allowance prices for NOx are assumed to stay at $0/ton because of Connecticut's exclusion from the Cross-State Air Pollution Rule (CSAPR) and because it is unlikely that the anti-backsliding provisions of that rule would be invoked under projected emission levels. (CSAPR was recently stayed by the D.C. Circuit Court of Appeals, but the analysis for this IRP assumes it will eventually proceed to implementation.) Prices for SO_2 allowances also are assumed to be $0/ton because of Connecticut's exclusion from the Cross-State Air Pollution Rule and because emission reductions in other states will keep emission allowance prices under the Clean Air Act Title IV acid rain program essentially at zero. Prices for CO_2 allowances are assumed to stay at roughly $2/ton, set by the Regional Greenhouse Gas Initiative (RGGI) price floor.[27] The analysis also assumes that no national climate policy based on cap-and-trade or carbon taxes will be implemented over the 10-year study horizon.

Using these data inputs, the DAYZER model simulates ISO-NE's operation of the electrical system and its administration of the energy market. The outputs of the model include hourly locational marginal prices (LMPs), dispatch costs, generation and emissions for every generating unit in New England, and transmission flows and congestion costs. The resulting annual average wholesale energy prices paid by Connecticut loads are $54.6/MWh in 2015, $56.3/MWh in 2017, and $61.5/MWh in 2022 in constant 2012 dollars, as shown in Figure 9, which also depicts monthly wholesale energy prices.[28] For comparison, annual average prices in 2008 were $87/MWh (when natural gas prices were much higher), then dropped to $45/MWh in 2009 before rising to $52/MWh in 2010 (all in 2012 dollars). About two thirds of the expected increase over time is due to rising natural gas prices. The remaining one third of the expected increase is due to less efficient generators setting market prices in more hours (higher "market heat rate") as the initial capacity surplus shrinks and load grows.

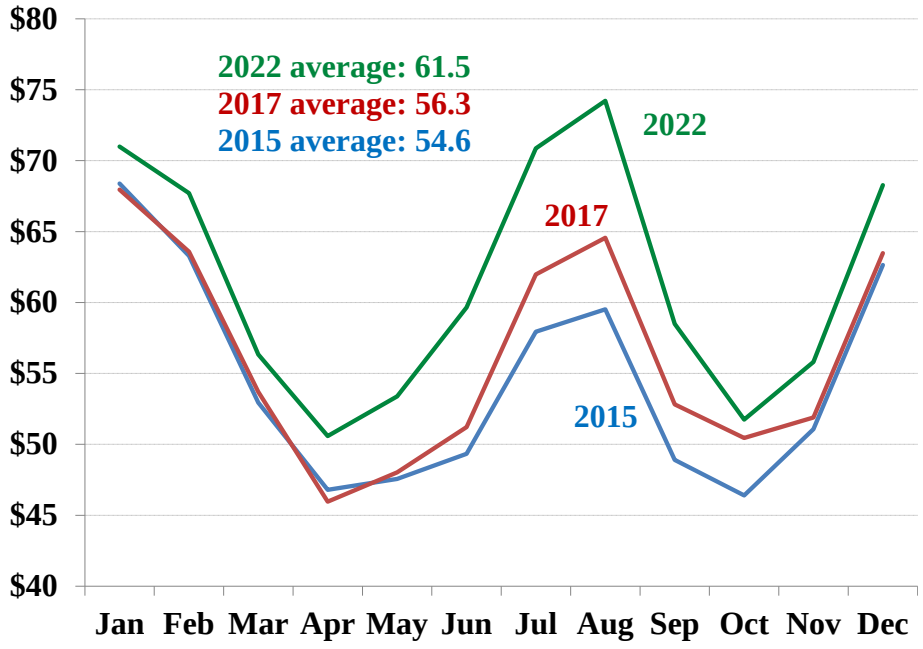
[25] Since the IRP analysis was conducted, natural gas prices have decreased. As of June 13, 2012, NYMEX Henry Hub Futures have decreased by roughly $1.40 per MMBtu (in 2012 dollars) for delivery in 2015 through 2020

[26] "Henry Hub" is a common reference pricing point located in Louisiana. "MMBtu" is one million British Thermal Units. All prices shown are annual averages, expressed in 2012 dollars.

[27] RGGI expires in 2018. This analysis assumes CO_2 prices remain the same thereafter, but such a low price has a trivial effect on the results.

[28] Load-weighted annual average energy prices are $65.3/MWh in 2015, $59.2/MWh in 2017, and $57.1/MWh in 2022 in constant 2012 dollars. Load-weighted average prices are greater than simple average prices because load is frequently higher when prices are higher.

Figure 9
Base Case Projection of Energy Prices (2012 $/MWh)



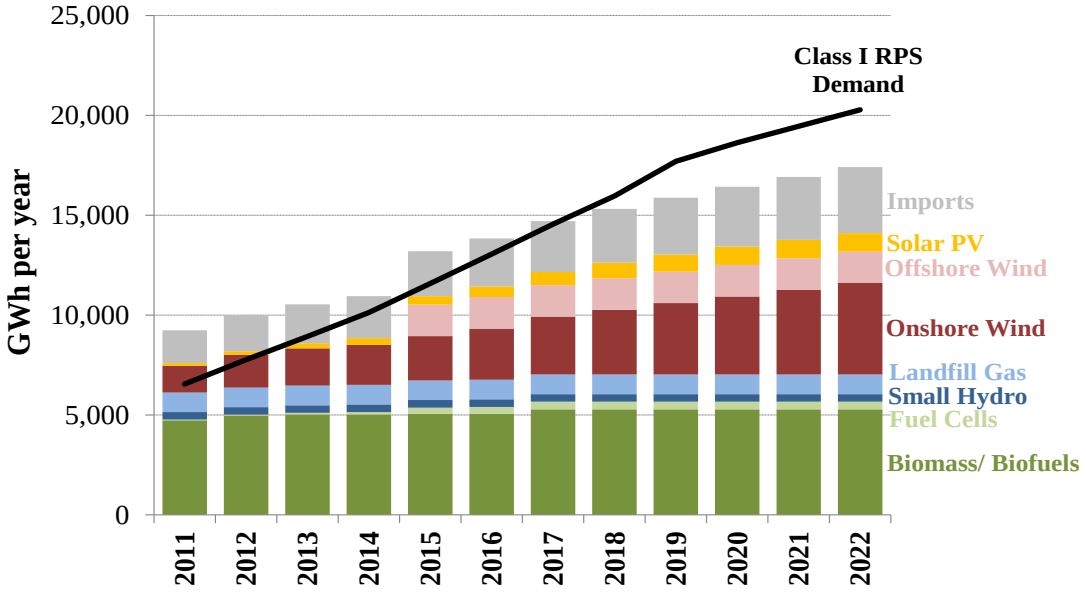
C. Supply and Demand for Renewable Generation

The demand for Class I renewable energy resources in New England is expected to almost triple over the next decade based on current state Renewable Portfolio Standard (RPS) rules and regulations. Among the New England states, Connecticut has the most ambitious Class I target as a percentage of load (12.5% in 2015, increasing up to 20% by 2020) and accounts for approximately one third of the regional renewable energy demand (second only to Massachusetts). Load serving entities in New England rely on a regional market for Class I Renewable Energy Credits (RECs) to comply with RPS requirements. Connecticut's regulations have some unique eligibility characteristics, with some resources qualifying for Class I status only in Connecticut. In estimating the supply and demand balance of the regional Class I REC market, the analysis has taken into account resources that are specific to Connecticut.

While the technical potential of renewable resources in the overall New England region remains high, tighter financial conditions over the past three years have made it increasingly difficult for new renewable resources to secure funding for construction. Based on information that is currently available, our Base Case projection of Class I renewable energy resources build-out shows that New England is likely to meet the regional demand through 2017, but may fall short in years beyond 2017. The projection through 2015 is based on information for projects that are currently under development as well as state-specific programs (including Connecticut's Project 150 and the ZREC/LREC programs). For years beyond 2015, DEEP presents a "likely" trajectory of renewable development based on recent historical trends and expected near-term additions. These assumptions include: (a) growing onshore wind capacity by about 115 MW per year; (b) adding new solar resources to meet carve-outs from targeted state programs; (c) not building new landfill gas and small hydro resources; and (d) increasing the eligible Class I REC

imports from New York and Canada at approximately 10% per year. Figure 10 summarizes supply and demand for Class I renewable energy in New England.

Figure 10
New England Class I Renewable Resource Supply and Demand Balance



Under the Base Case, Class I renewable cost assumptions and simulated REC market, the market price for Class I RECs would be approximately $23/MWh while the market is in relative surplus (2012 through 2017). Beyond 2017, however, the REC shortfall implies that REC prices would rise to the level of the Connecticut Alternative Compliance Payment (ACP), which currently is the lowest in New England.[29] REC prices would clear the market at $55/MWh ($45/MWh real 2012 dollars), which is the level of the Connecticut Alternative Compliance Payment. Brattle estimates that the cost of complying with the Class I requirements will increase from $118 million in 2012 to $445 million in 2022. Under these conditions, Connecticut utilities would satisfy nearly half of their RPS obligations through Alternative Compliance Payments. These payments could be avoided if the pace of renewable energy development accelerates in the New England region. For example, more projects could be developed if transmission is constructed to access remote onshore wind resources, if costs decline more than expected, or if financing improves. Connecticut or other states could also consider offering long-term purchase power contracts to provide a more reliable revenue stream to renewable energy projects.

In addition, DEEP evaluated Class II and Class III supply and demand. Overall Class II and III supply and demand is summarized in Appendix D. Class II requirements are initially set at 3% and currently no change in that level is anticipated. The current supply of Class II and Class III resources significantly exceeds the existing RPS requirements. This drives the Class II REC

[29] Alternative Compliance Payments (ACP) represent an administrative cap on REC prices, which entities can pay to states in lieu of purchasing RECs if they are unavailable or too expensive. Other New England states have indexed their ACP to inflation, while Connecticut set the level at $55/MWh without providing for any inflation adjustment. Other New England states' ACP levels for Class I requirements are currently $62/MWh, escalating at the consumer price index.

prices down to less than $5/MWh and the Class III REC price to the price floor of $10/MWh and prevents some of the resources from receiving any REC payments at all.

Resource recovery facilities largely comprise Class II generation in Connecticut. Historically, long-term contracts with the EDCs have been necessary to ensure the economic viability of these facilities with the expectation that proceeds from the Class II market would provide a sustainable future revenue source. However, many long-term contracts have ended the Class II market is currently oversupplied, energy prices have declined and operating costs have increased. Reduced revenues, unsold RECs and increased costs have created financial hardship and raise concerns about significant environmental consequences for the future of the State's management and disposal of trash. Additional concerns such as higher tipping fees for municipalities and electricity market conditions must also be considered as DEEP evaluates potential solutions to this immediate problem and develops a plan to address the continued viability of these facilities.

Conservation and energy produced by combined heat and power facilities comprise Connecticut's Class III market. Sales of Class III RECs provide an estimated $4.5 million in supplemental revenues for utility conservation programs. This additional funding, while helpful, is not essential to the utility conservation effort. Oversupply in the Class III markets has resulted largely from continued growth in energy efficiency programs and has impacted third-party conservation efforts. Low REC prices have also impacted existing CHP units and reduced incentives for additional development. The Class III requirement and associated market needs to be reevaluated if Connecticut is to continue to support combined heat and power and/or third-party sponsored energy efficiency through the RPS.

DEEP estimates the cost of Class II RECs to be approximately $4.5 million in 2012. The cost of Class III RECs is estimated at $13 million. These costs should remain about the same through 2020 since the RPS requirements do not change. Utility conservation will increase, keeping REC prices at the floor level and making more Class III RECs unmarketable. Class II REC prices and costs should also remain the same unless some of the existing resource recovery facilities retire.

D. Outlook for Customer Rates

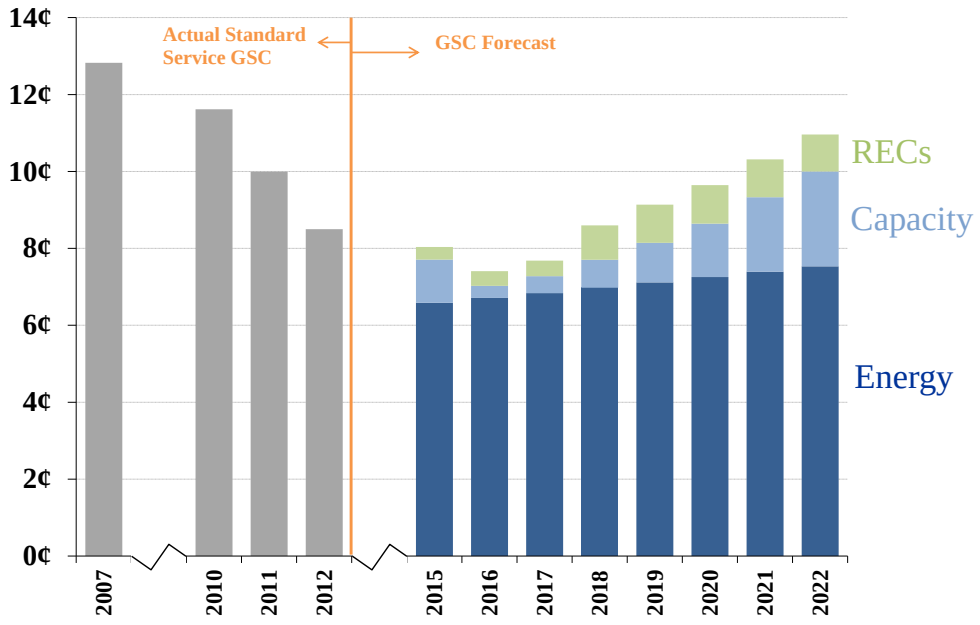
The IRP analysis projects Generation Service Costs (GSC) for Connecticut customers, averaged across all rate classes. Generation Service Costs currently comprise approximately half of the total customer bill. Based on the capacity, energy,[30] and REC market projections described above, DEEP projects that Generation Service Costs should remain relatively constant in real terms, at approximately 8 ¢/kWh from 2012 through 2017, as shown in Figure 11.[31] That is substantially lower than rates experienced over the past several years, primarily because Henry Hub natural gas prices are expected to remain below $6/MMBtu and capacity prices are expected

[30] In Figure 11, "energy" costs include the costs of electrical loss net of loss refunds, congestion costs net of financial transmission rights (FTR) revenues, and an estimated 10 percent adder to account for other ISO-NE charges and a risk premium.

[31] The Generation Service Costs shown in Figure 11 do not include other components of customer bills, such as transmission and distribution (T&D) costs, the net costs of mandated renewable investments (ZREC/LREC or Project 150 programs), or the cost of long-term contracts with the Kleen Generation, AMERESCo energy efficiency, Waterbury Generation or Waterside Generation and the new peaking facilities.

to stay below $4/kW-month. For comparison purposes, Figure 11 shows estimated historical and current rates for Standard Service for residential and small commercial and industrial customers in 2007, 2010, 2011, and 2012.[32]

Figure 11[33]
Annual Average Generation Service Costs for Connecticut Customers (2012 ¢/kWh)
Base Case Projection



From 2017 to 2022, Generation Service Costs are likely to increase by slightly more than 3 ¢/kWh, as shown in Figure 11. This projected increase is driven by three factors. First, 1.9 ¢/kWh of the increase is from rising capacity prices. In 2017, prices will likely reach their lowest levels of about $1/kW-month after the current price floor expires and the market price drops to clear the existing capacity surplus. Thereafter, prices will rise as regional load grows. By 2022, prices will likely rise to $7/kW-month, near the equilibrium levels customers can expect to pay on a long-term average basis in order to attract new generation resources.

Second, 0.6 ¢/kWh of the increase is from the cost of Renewable Energy Credits (RECs) and Alternative Compliance Payments (ACP). The volume of renewable energy purchased increases as the Class I requirement increases, but the price also increases as the scarcity of regional supply causes the REC price to be set by the Connecticut Alternative Compliance Payment. In addition, outside the Generation Service Charge, there would be approximately a 0.2 ¢/kWh increase for transmission to support increased Class I resources, although the cost is highly

[32] Estimated Standard Service rates shown in Figure 11 are based on a weighted average of filed rates for CL&P (80%) and UI (20%), converted to 2012 dollars. These rates apply only to residential and small commercial and industrial customers that choose to take retail service from the Electric Distribution Companies. Hence, these rates are not strictly comparable to the projected future rates shown in Figure 11, which represent an average across all customers in the state.

[33] In nominal terms, rates are estimated at 8.49 ¢/kWh in 2015, 8.45 ¢/kWh in 2017, and 13.29 ¢/kWh in 2022

uncertain and the modest rate impact assumes Connecticut pays for only its 25% load-ratio-share of the total estimated transmission costs.

Third, 0.6 ¢/kWh of the increase is from rising energy prices, approximately two-thirds of which is caused by natural gas prices rising, and one-third is caused by market heat rates increasing as load grows.

In this IRP, DEEP has identified and evaluated various opportunities to counteract some of the rate increases projected for the 2017-2022 period. One general approach is to help customers reduce the volume of consumption, and thus save money, especially when rates are higher. Another approach is to facilitate the development of low-cost resources that are economic (but may face barriers to implementation), which could defer the market price increases necessary to attract higher-cost resources. A third is to find more cost-effective ways to meet the clean energy objectives of the RPS. The Resource Scenarios section of this IRP addresses all of these approaches. As discussed below, DEEP concludes that increased energy efficiency can help meet all of these objectives and counteract more than half of the projected cost increases through 2022.

In addition to these resource approaches, DEEP is cognizant of the impact ISO-NE has on shaping the regional energy market. As such, DEEP will continue to participate actively in the ISO-NE stakeholder process to ensure that the market is working effectively to achieve reliability objectives at reasonable cost, and to ensure that the market reasonably accommodates Connecticut's energy policy objectives. DEEP will also be issuing a separate report that examines trends for all rate components, identifying factors impacting rates and providing recommendation to lower electric rates and bills for Connecticut customers. DEEP will issue this report in compliance with Section 90 of Public Act 11-80.

E. Fuel Use and Emissions Outlook

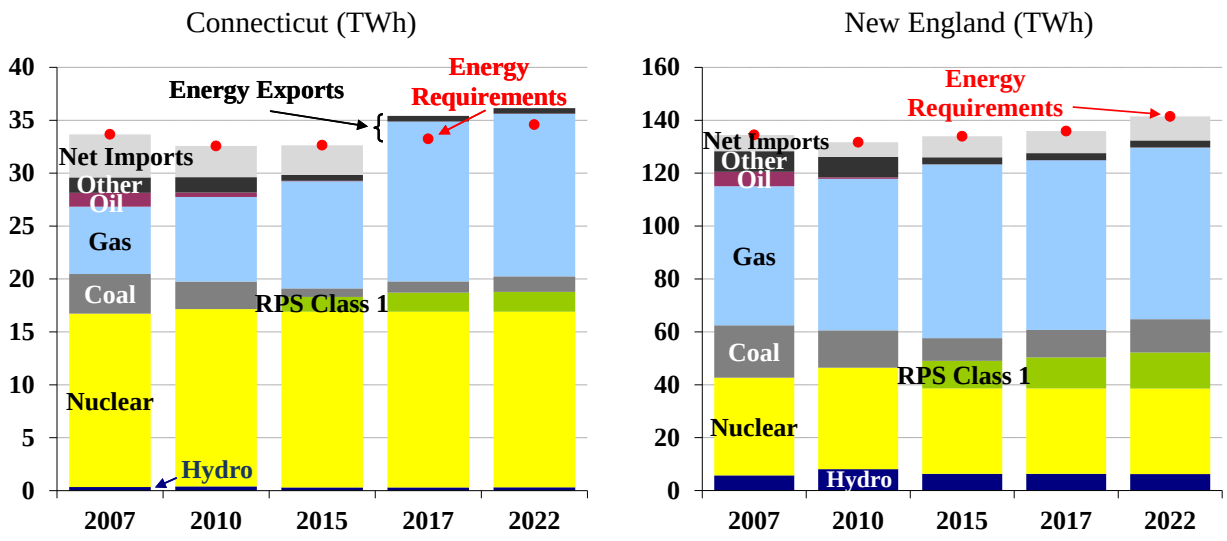
Electricity production and prices in New England today are markedly different from what the region experienced in the past decade. DEEP expects further changes over the next ten years. The primary reason for these past changes are dramatic shifts in relative fuel prices (reflecting low natural gas prices coupled with high coal and oil prices) while environmental retrofits, economic retirements, and new renewable generation will have increasing influence in the coming decade. For example, oil-fired generation decreased after 2007 partly because of increased availability of lower-cost natural gas-fired generation and renewables, but also because of changes in fuel prices. Oil prices have risen dramatically relative to natural gas prices, and are expected to remain high.

The combined effect of these changes on total generation by fuel type is shown in Figure 12 below, which includes 2007 actual data and projections for 2015, 2017, and 2022 for Connecticut and New England.[34] This shows the increase in renewable generation from 6% of total New England supply in 2007 to 10% in 2020, a 36% reduction in coal generation, and a steep decline in oil generation. Total generation in Connecticut has increased, mostly because of

[34] Regional natural gas and oil generation for historical years are estimated by The Brattle Group based on publicly-available data from ISO-NE. For forecast years, generation is simulated in the DAYZER model.

the 2011 addition of the Kleen generation facility, an efficient 620 MW natural gas-fired combined-cycle plant; with the expectation that Lake Road (a 745 MW natural gas-fired combined-cycle plant) will be electrically incorporated into the Connecticut sub-area upon completion of the Interstate portion of the New England East-West Solution transmission project at the end of 2015. These changes would convert Connecticut from a net energy importer to a net exporter by 2017.

Figure 12. Base Case Projection of Annual Generation by Fuel Type



DEEP projects that displacement of coal and oil generation by gas and renewable generation will continue to produce a dramatic reduction in regional NOx, SO_2, and CO_2 emissions relative to historic levels.

- *CO_2*. As shown in Figure 13, Connecticut CO_2 emissions have already decreased from 9.7 million tons in 2007, and are projected to decrease to 7.8 million tons by 2015 then slowly rise to 8.5 million tons by 2022. New England as a whole is expected to follow a similar curve, staying well below the targets established under the Regional Greenhouse Gas Initiative.[35]
- *SO_2*. As shown in Figure 14, Connecticut's power sector SO_2 emissions are expected to be a small fraction of past emissions. For example, 2010 emissions were 70% lower than in 2007; 2015 emissions are projected to be another 45% lower than 2010 emissions. By 2022, emissions are projected to grow back to 90% of 2010 levels, but still 73% below 2007 levels.
- *Annual NOx*. Figure 15 shows a substantial reduction in Connecticut's power sector NOx emissions, with only modest increases after 2015 as load grows. For example, 2010 emissions were 36% lower than 2007 emissions; 2015 emissions are projected to be half of that. After 2015, emissions are projected to grow slowly back to two-thirds of the 2010 level by 2022.

[35] In Figure 13 through Figure 16, "RPS Class I" includes biomass and fuel cells that are RPS-qualified. "Other" includes refuse and biomass that are not RPS qualified.

- *High Energy Demand Day NOx.* Figure 16 shows NOx emissions on just the top 10 High Energy Demand Days (HEDD), both for Base Case normal weather and for "90/10" weather representing a hottest summer expected in 10 years. These projections compare favorably to an average of 30 tons per day experienced on the 4 hottest days in each of 2007 through 2010, and the target level of 42.7 tons per day that Connecticut has committed to the Ozone Transport Commission.

Figure 13. Annual CO_2 Emissions

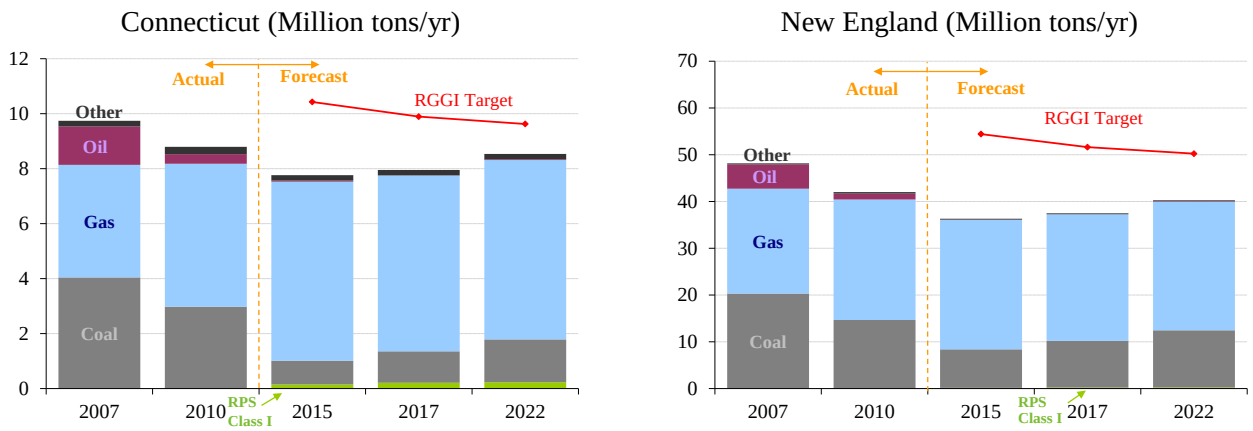


Figure 14. Annual SO_2 Emissions

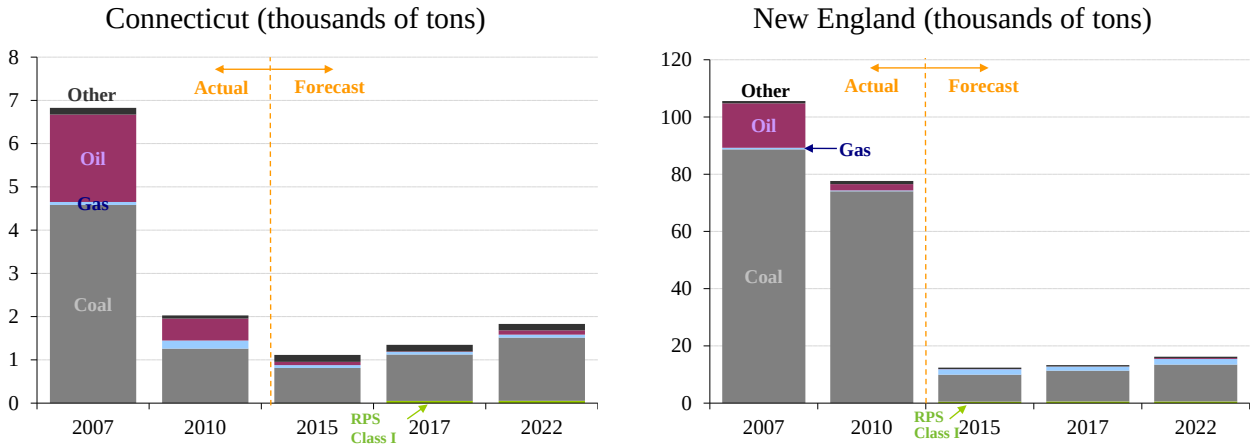


Figure 15. Annual NO_X Emissions

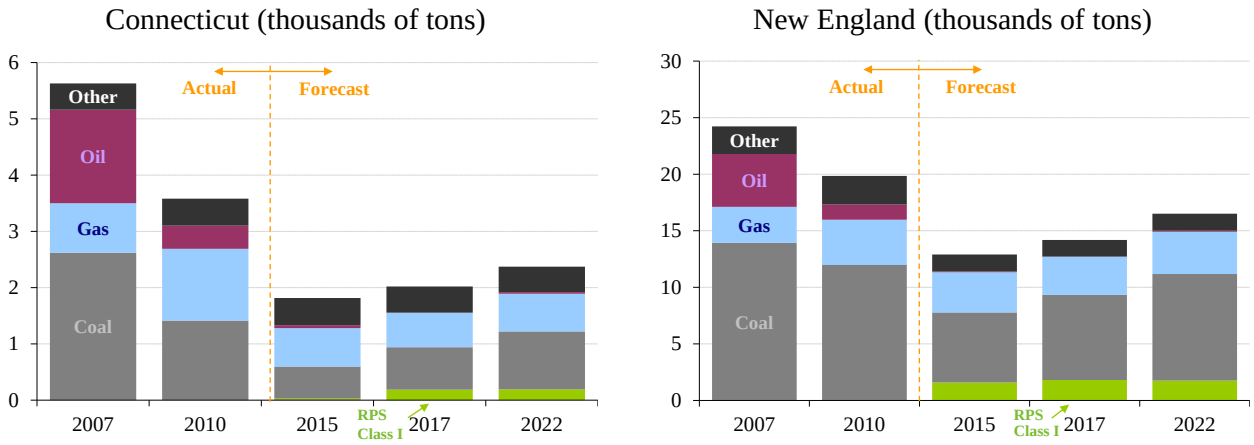
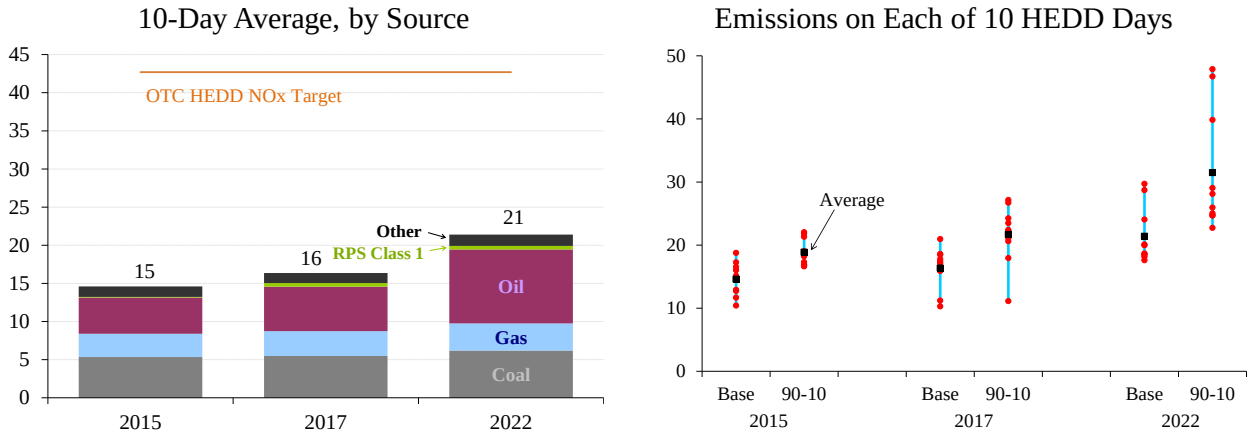


Figure 16. HEDD NOx Emissions in Connecticut (tons per day)



V. ALTERNATIVE FUTURES

A. Definition of Futures

Long-range planning analysis must address uncertainty in order to be useful. Regardless of the effort and attention that goes into the analysis, it is impossible to perfectly predict key external factors—such as natural gas prices and economic growth—over which regulators and utilities do not have direct control. This produces substantial uncertainty about important outcomes such as resource needs, rates, and emissions. Moreover, the costs and benefits of alternative resource strategies often differ as external factors vary. Hence, potential resource strategies must be evaluated under a range of market conditions. Simply setting each external (exogenous) factor to a single most likely value seldom provides insight into how strategies might perform under alternative market conditions. For this IRP, DEEP analyzed uncertainty by constructing scenarios, which we call "Futures" to distinguish from "Resource Scenarios," which are evaluated in the next section. The Futures are based on different natural gas prices and the relative amounts of supply and demand, while holding all other variables at their Base Case

values.[36] With respect to supply and demand, the "Tight Supply" future incorporates ISO-NE's high economic growth load forecast (1,150 MW higher by 2020), and does not allow active demand response to adjust to capacity price changes. The Tight Supply future also assumes Boston's local resource adequacy problems are solved with transmission instead of adding internal resources. The "Abundant Supply" future incorporates ISO-NE's low economic growth load forecast (1,150 MW lower by 2020) and assumes that the Vermont Yankee nuclear plant remains in service during the study period. These two Futures thus span a large range of circumstances, covering any number of unanticipated changes that could have similar effects on the regional supply-demand balance, such as new imports of Canadian hydropower, changes in retirements, imports, demand response, and new capacity. They are useful for testing the robustness of alternative Resource Scenarios against a range of very different pressures on resource adequacy.

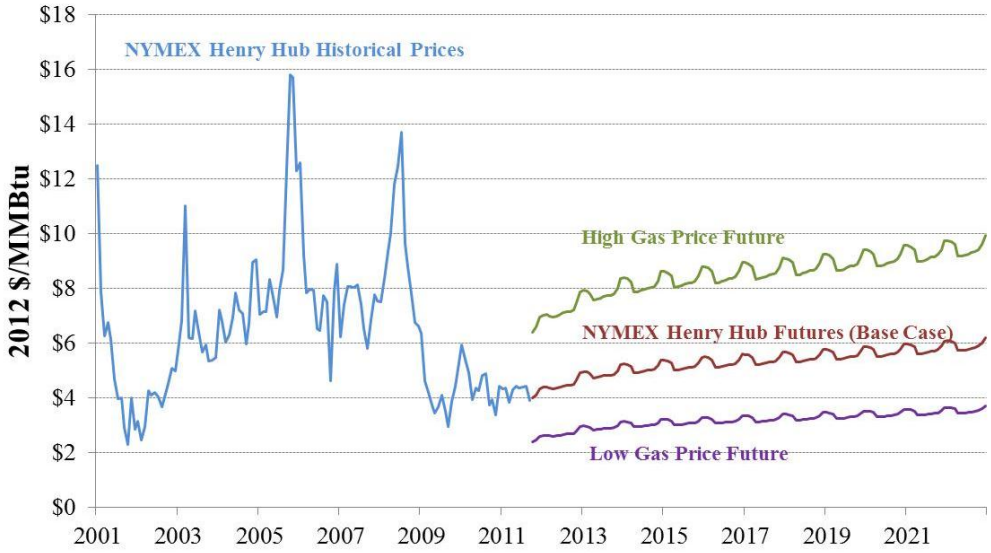
With respect to natural gas prices, the futures reflect the fact that natural gas price uncertainty directly affects electricity price projections. In developing the high and low commodity price cases, DEEP evaluated several factors including available high and low natural gas price forecasts from the U.S. Energy Information Agency (EIA), Wood Mackenzie, implied volatility from natural gas options prices, and historical "forecast errors" derived from comparing historic projections to realized gas prices. Considering all of the available data, it was determined that a high/low range relative to the Base Case commodity price forecast of roughly +60% to -40% captured a reasonable range of long-term natural gas prices suitable for planning purposes. The resulting price trajectories are shown in Figure 17, which also includes historical prices for comparison purposes. Figure 17 does not show transportation basis differentials or LDC charges, which are assumed to be identical to those in the Base Case.

In developing these natural gas price futures, elasticities of demand were applied to account for customers' likely responses to large, long-term natural gas price-induced changes in electricity prices.[37] A long-term elasticity of *energy* demand of -35% reduces energy consumption in the High Gas future by 13.4 terawatt-hours (TWh) in 2015 (10.0%) and by 14.4 TWh in 2022 (10.2%). It increases load in the Low Gas future by 8.9 TWh in 2015 (6.7%) and by 9.6 TWh in 2022 (6.8%). A long-term elasticity of *peak* demand of -17.5% reduces peak load in the High Gas future by 1,400 MW in 2015 (5.0%) and by 1,500 MW in 2022 (5.1%). It increases peak load in the Low Gas future by 900 MW in 2015 (3.3%) and by 1,000 MW in 2022 (3.4%).

[36] Varying the Cost of New Entry was also considered and analyzed, but not used to construct an alternative Future because it had only a small effect on the outcomes.

[37] Elasticity is a measure of quantity response to price changes expressed as a quotient of percentage changes over a given time period. For example, if price increases by 1% and quantity demanded falls by 0.5%, then the elasticity of demand is -50% (-0.5/1).

Figure 17
Natural Gas Price Trajectories at Henry Hub



B. Costs and Emissions under Alternative Futures

The four alternative Futures described above were evaluated using the same modeling system used to develop the Base Case. Cost and emissions metrics are shown in Figure 18 through Figure 26, below. Some of the most salient observations from these figures are as follows:

- *Resource Adequacy*. Whereas new generation entry is not found to be economic for meeting the region's Net Installed Capacity Requirement in the Base Case until 2022, economic entry could occur in 2018 in the Tight Supply future, and 2019 in the Low Gas future as a consequence of higher load growth. The resulting range in capacity prices is shown in Figure 18. In all Futures, new generation is not necessary in Connecticut specifically in order to meet the Local Sourcing Requirement.

  As noted in Section IV, subsection A, the IRP assumes all four components of the NEEWS transmission project are constructed, increasing the Connecticut import limit to 1,100 MW and incorporating the Lake Road generating facility into Connecticut. In the event that the Interstate and Central Connecticut components of NEEWS were not constructed, Connecticut would still have adequate local resources to maintain reliability even in the Futures with higher load. For example, in the Low Gas future, higher projected capacity prices prevent some generation retirements and attrition of demand response, which offsets the higher load.

- *Costs and Rates*. The High Gas future has higher rates and the Low Gas future has lower rates than the Base Case primarily because of differences in wholesale energy prices shown in Figure 19. However, cost impacts are partially mitigated by demand elasticity effects, as shown by the smaller

variation in the costs in Figure 20 compared to the rates. Costs and rates are also lower in the Abundant Supply future. Note that the rate increases over time are greater than the uncertainty across Futures in any particular year, as shown in Figure 20.

- *Generation*. As load varies across the Futures, most of the variation in generation is projected to occur in gas-fired units. Little dispatch switching occurs between fuels, except in the High Gas future, where coal generation increases at the expense of natural gas. In all of the Futures, the old, high-emitting oil-fired steam units would not generate at significant levels, as shown in Figure 25 and Figure 26.
- *Emissions*. The Futures with higher load (Tight Supply and Low Gas) have higher emissions, except High Gas, which has higher SO_2 and NOx emissions, as shown in Figure 21, Figure 22, Figure 23, and Figure 24. The relative emissions levels across cases are driven by a number of factors. For example, in the Abundant Supply future, emissions would decrease from 2015 to 2017 because the low load and presence of Vermont Yankee cause many retirements when the capacity price floor expires, including coal retirements. In the Tight Supply future, CO_2 emissions decrease from 2017 to 2022 because of the addition of 2,100 MW efficient combined-cycle plants. NOx is higher than in the High Gas future because high-emitting units are needed to meet a much higher peak load. In the Low Gas future, High Energy Demand Day NOx is higher than in the High Gas future because peak load is much higher.

Figure 18. Capacity Prices in New England (2012 $/kW-Year)

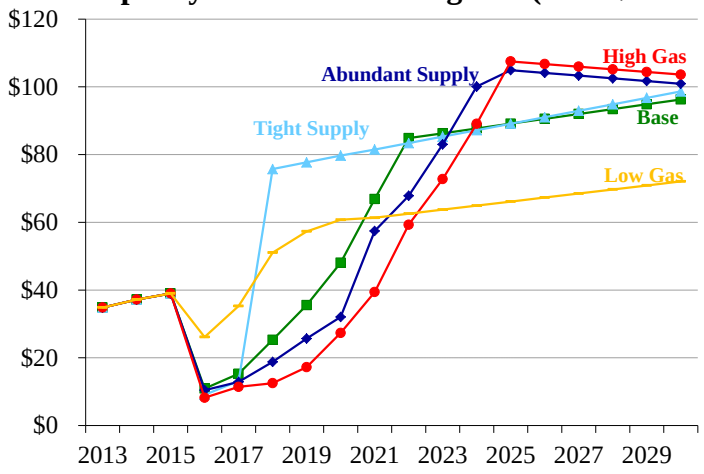


Figure 19. Annual Average Energy Prices in Connecticut (2012 $/MWh)

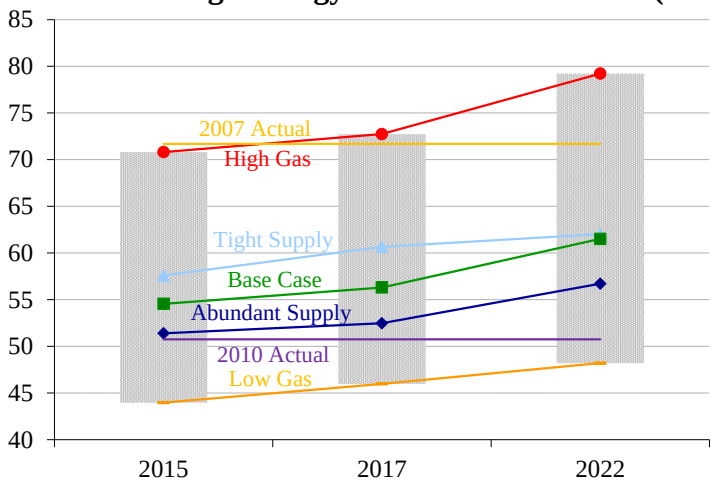


Figure 20. Connecticut Customers' Power Supply-Related Costs
(Includes GSC costs, EE charges, and Transmission charges associated with remote renewable generation)

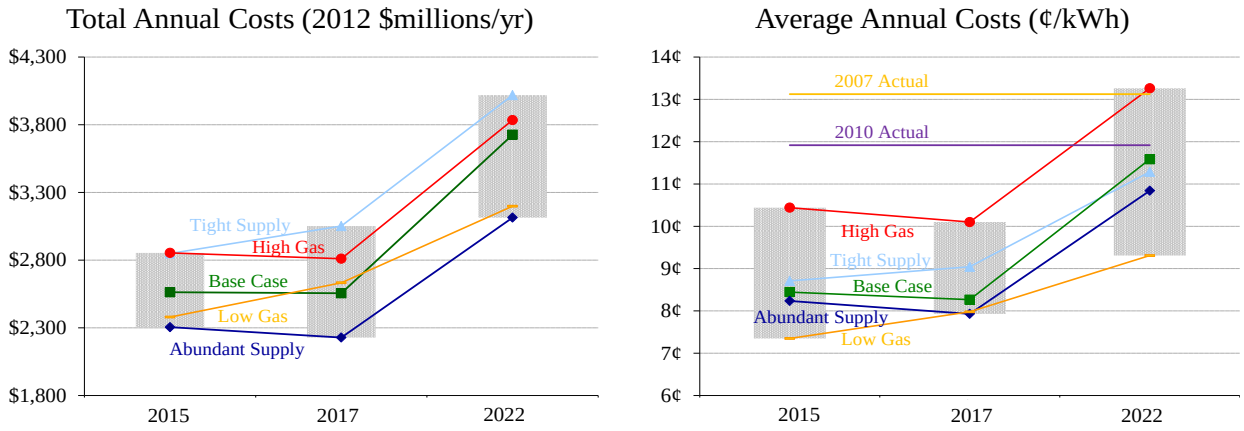


Figure 21. Annual CO_2 Emissions

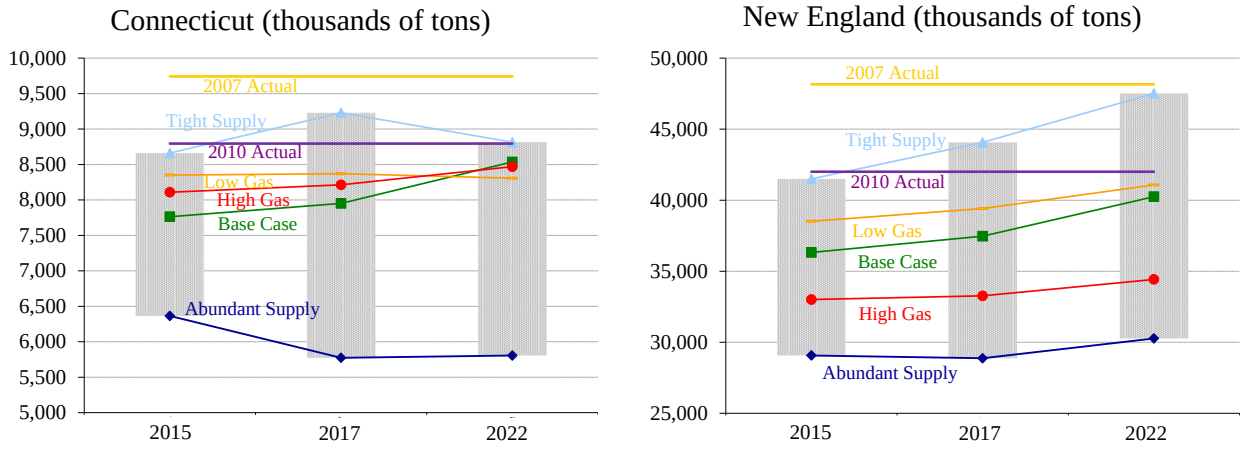


Figure 22. Annual SO_2 Emissions

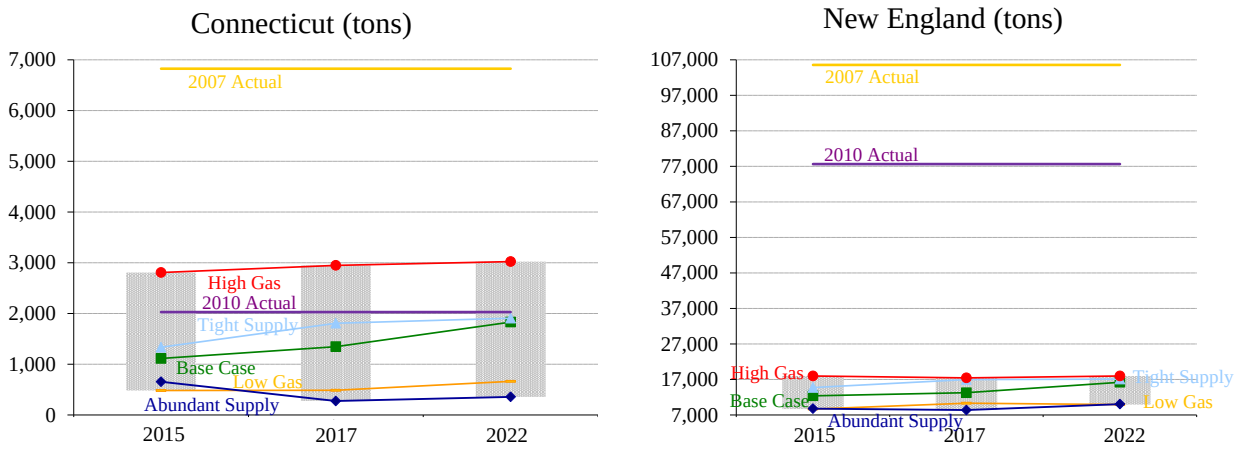


Figure 23. Annual NO_X Emissions

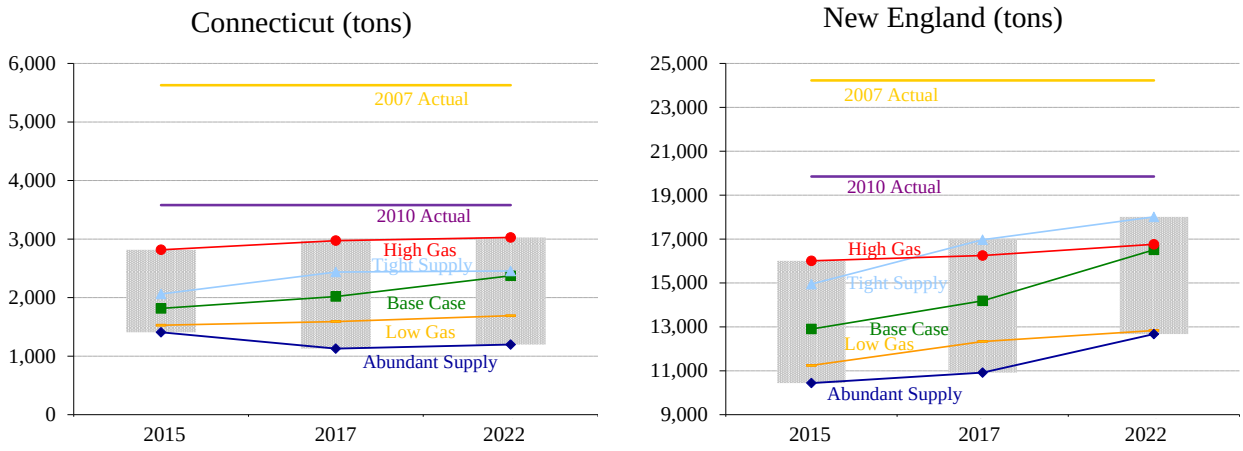


Figure 24
Connecticut HEDD NOx Emissions on Each of 10 HEDD Days (Daily Tons)

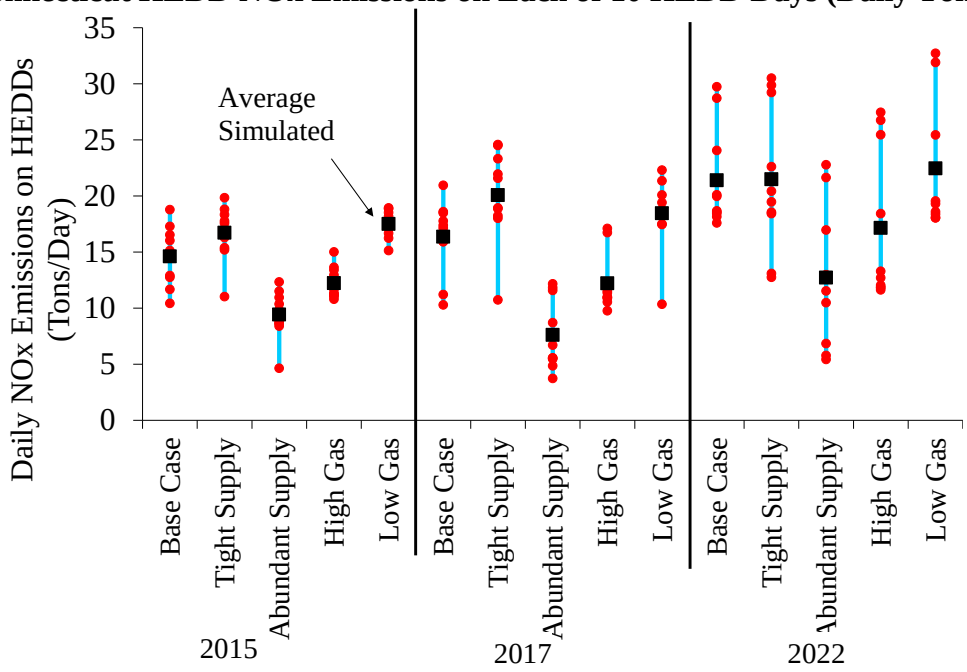


Figure 25
Connecticut Generation by Fuel Type (TWh)

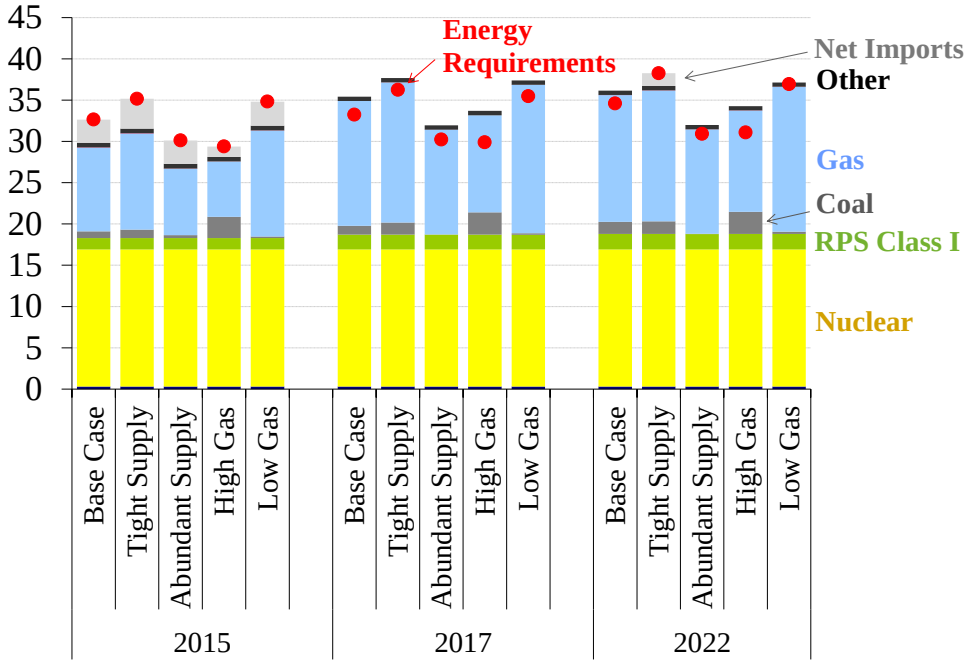
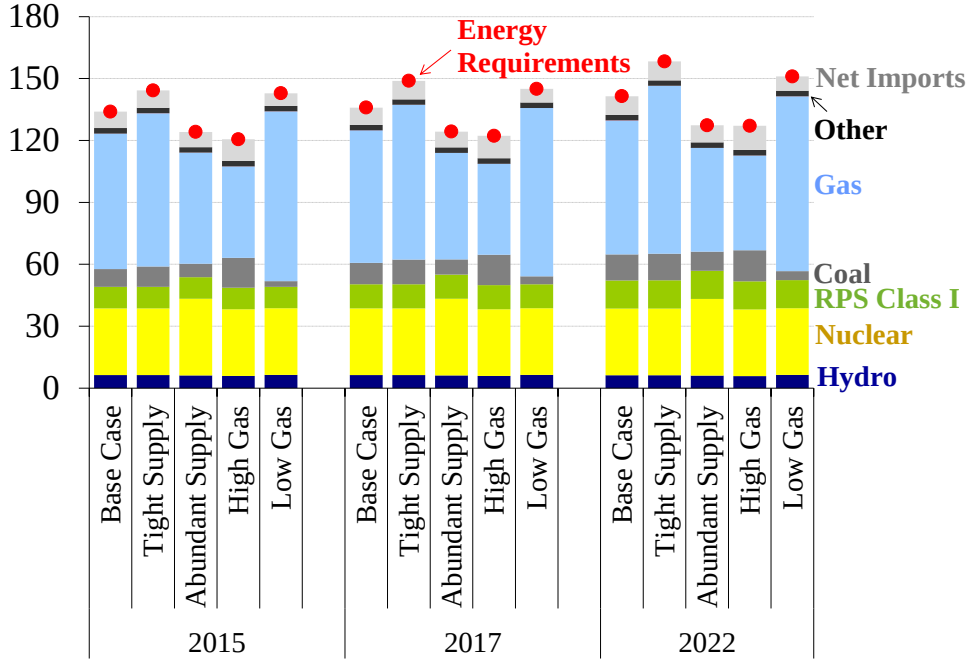


Figure 26
New England Generation by Fuel Type (TWh)



VI. EVALUATION OF RESOURCE SCENARIOS AND PLAN FOR SECURING RESOURCES

This section of the IRP introduces a plan for securing energy resources to minimize the cost to Connecticut customers over time and maximize consumer benefits consistent with the state's environmental goals and standards. This plan is based on the analysis of projected future electricity supply and demand, discussed above, as well as several resource scenarios evaluated for this IRP. It addresses opportunities in four key areas: promoting more energy efficiency through various policy approaches, meeting and/or redefining the RPS standards in various ways, fostering the development of new transmission, and facilitating the entry of new generation.[38] In developing this plan, DEEP tested several possible courses of action as "Resource Scenarios," acknowledging the fact that the State cannot fully control all of the factors examined, even if it can influence them. The Resource Scenarios evaluated in this IRP are defined as follows:

- *Expanded Energy Efficiency.* While the Base Case assumes continuation of energy efficiency programs at current levels, DEEP evaluated an Expanded Energy Efficiency resource scenario that nearly triples that amount of energy savings over the next decade. The opportunities for increased efficiency and

[38] Procurement and risk management strategies can also affect customer rates, but they are not considered here because Public Act 11-80 addresses procurement outside of the IRP.

the costs of achieving them are based on the Potential Study commissioned by the Energy Conservation Management Board (ECMB), dated April 2010.

- *RPS Scenarios.* DEEP evaluated the effects of maintaining the existing Class I RPS requirements. Acknowledging current uncertainty about how the RPS requirements could be met, DEEP examined three levels of Class I development: a Low Case, a Base Case, and a Full Renewables Buildout.
- *New Cost of Service (COS) Generation.* This scenario assumes the development of one new, efficient 656 MW gas-fired combined-cycle plant in Connecticut in 2017 (for $929/kW cost in 2012 dollars, excluding interest during construction), backed by power purchase agreements or other support from Connecticut customers. DEEP analyzed this scenario in order to asses the value to Connecticut customers of paying the full cost of new conventional generation and receiving its full market value, and doing so before such a resource would have been developed by merchant developers.

The subsections below describe the Resource Scenarios and their impacts on costs, rates, emissions, and jobs. Resource scenario evaluations are presented here for the Base future but were also evaluated across alternative futures, the results of which are included in Appendix A (Detailed Tables).

A. Expanded Energy Efficiency

To identify opportunities for securing Connecticut's energy resource needs through energy efficiency, DEEP tested an Expanded Energy Efficiency resource scenario based on the "Potential Study" sponsored by the Connecticut Energy Conservation Management Board (ECMB), conducted by KEMA Consulting, and filed in 2010.[39] The Potential Study estimates the savings that could be achieved based on a detailed, bottom-up analysis of hundreds of available energy conservation measures in each customer sector, and then applies a benefit-cost test to each measure to estimate an economic potential. Most of the measures are based on programs already being implemented by the electric distribution companies. Many of the measures evaluated in the Potential Study would involve significantly expanding the more innovative parts of existing programs, such as offering technical training to commercial customers on more efficient practices.

Based on the KEMA Potential Study estimates, the Expanded Energy Efficiency resource scenario estimates maximum cost-effective savings from energy efficiency programs over an 11-year implementation schedule from 2012 through 2022, as shown in Figure 27.[40] The Expanded Energy Efficiency scenario estimates that by expanding current efficiency savings to the maximum cost-effective level each year from 2012-2022, the resulting achievable, cost-effective savings will exceed Base Case energy efficiency savings by $534 million annually by 2022.These savings will exceed Base Case Energy Efficiency program savings by 1,071 MW

[39] The ECMB has since been renamed the Energy Efficiency Board.

[40] The reason the annual incremental savings from the Expanded Energy Efficiency scenario appear lower in the initial years is that the Base Case Energy Efficiency savings against which it is measured were assumed to decline over time.

(annual peak), and 4,339 GWh (annual energy) by 2022.[41] This finding is the basis for the Expanded Energy Efficiency scenario DEEP utilized in this IRP. Because each program measure would save energy over the entire multi-year life the equipment is installed, the savings from each year's measures would accumulate on top of prior years' savings as the electricity-using capital stock becomes increasingly efficient.

According to DEEP's model estimates, the annual cost of achieving this higher level of energy efficiency is $243 million more than the Base Case, comprising an incremental $105 million program budget, and an incremental $138 million in increased out-of-pocket spending by program participants to pay for their share of the efficiency measures.[42] The total implementation unit cost per kWh saved under the Expanded Energy Efficiency scenario is assumed to be similar to that in the Base Case. However, the participant is assumed to pay a larger share of total costs (i.e., receive lower program incentives than in the Base Case). This reflects an assumed expansion in the availability of financing over time, such as through the programs being developed by the Connecticut Clean Energy Finance and Investment Authority (CEFIA). If the program incentives were similar to those in the Base Case, the incremental rate increases would have to be 0.2 to 0.3 ¢/kWh higher.

Figure 27 shows the incremental savings and ratepayer program costs in the Expanded Energy Efficiency scenario relative to the Base Case. The $138 million in annual participant costs is not included in the table. These costs and savings are the quantities that are analyzed below in our economic evaluation of the Expanded Energy Efficiency scenario compared to energy efficiency assumed in the Base Case.

Figure 27.
Incremental Savings and Ratepayer Costs of Expanded Energy Efficiency
(Incremental to Base Case Energy Efficiency)

		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Annual Savings from Just This Year's Incremental Measures	*(GWh)*	366	377	383	388	392	397	401	407	408	409	411
Annual Savings from the Cumulative Effect of All Incremental Measures to Date	***(GWh)***	**366**	**743**	**1,126**	**1,515**	**1,906**	**2,303**	**2,704**	**3,111**	**3,518**	**3,928**	**4,339**
Annual Savings from Just This Year's Incremental Measures	*(MW)*	95	96	97	97	97	98	98	98	98	98	99
Annual Savings from the Cumulative Effect of All Incremental Measures to Date	***(MW)***	**95**	**191**	**288**	**385**	**482**	**579**	**677**	**776**	**874**	**972**	**1,071**
Annual Incremental Utility Budget	***($Mil)***	**105**	**107**	**107**	**107**	**106**	**106**	**106**	**106**	**106**	**106**	**106**

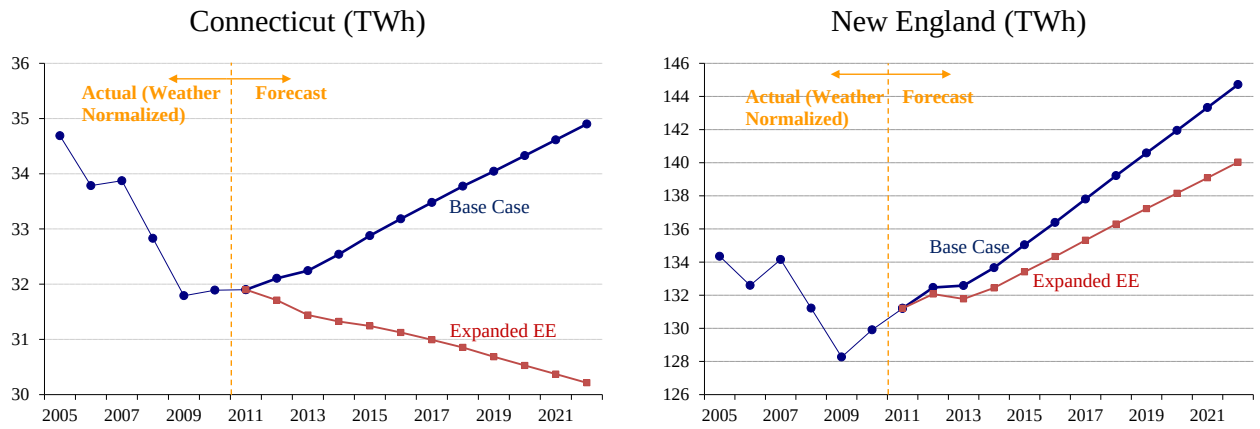
Implementing the Expanded Energy Efficiency scenario would support a growing economy that uses less energy both per unit of output and in absolute terms. Figure 28 shows that realized energy consumption in Connecticut would continually decline by about 0.4% per year net of the

[41] These savings are quantified in the Potential Study's "Program Achievable Potential" scenario. The Potential Study reports 6,616 GWh of total program savings in the Program Achievable Potential, but only 4,339 is incremental to 2,277 GWh of program savings in the Base Case (with the "absolute" savings in each case measured relative to having no programs). Both the Base Case and the Expanded Energy Efficiency cases are assumed to have the same amounts of naturally-occurring energy efficiency and compliance with existing or planned codes and standards already implicitly embedded in the load forecast.

[42] The annual cost of implementing the Expanded Energy Efficiency scenario is $206 million in program costs and $192 million in program participant out-of-pocket costs, which is $105 million and $138 million more, respectively, than the $101 million in program costs and $54 million in program participant costs in the Base Case.

effects of projected economic growth.[43] Relative to the base case, the Expanded Energy Efficiency scenario and would result in 4,339 GWh savings in 2022 from the cumulative effect of all incremental measures to date.[44] This projection of lower electric sales highlights the need to consider new business models for utilities that enable them continue making adequate returns in the face of declining sales from successful programs. DEEP will analyze alternative business models in order to develop recommendations for different rate structures that would achieve this goal, including: decoupling the distribution revenues from the volume of sales and reassessing shareholder incentives for successfully achieving energy efficiency savings. DEEP and the Energy Efficiency Board (EEB) will develop performance metrics for the programs and will call on the EEB to implement them.

Figure 28.
Effect of Expanded Energy Efficiency on the Energy Forecast



43 This projected decline rate does not account for the possibility that customers might engage in more energy-consuming activities when their equipment becomes more efficient—the so-called "rebound" and "snap-back" effects. Such effects would offset some of the projected savings.

44 In order to isolate the impacts of Connecticut investing in Expanded Energy Efficiency, utility programs in the rest of ISO-NE were assumed to remain the same as those used in the Base Case.

EXPANDED ENERGY EFFICIENCY — THE BASICS

What is "energy efficiency"?

Energy efficiency refers to using less energy to achieve the same level of service. For instance, installing efficient lighting in homes and businesses results in the same illumination while drawing less energy from the grid. Insulating a home allows one to maintain a given temperature by using less heating or cooling energy.

Why are energy efficiency programs needed?

Energy efficiency is implemented partly through end-users' own initiatives and partly through codes and standards. However, this is typically not enough to achieve all possible cost-effective energy efficiency due to various well-known barriers: poor customer information about energy efficiency; split incentives between building developers, owners, and tenants; lack of access to capital; and an inability of the individual customer to capture all of the benefits associated with reduced system transmission and distribution investment needs, reduced emissions, and increased energy security. Energy efficiency programs are intended to help overcome such barriers.

What do energy efficiency programs do?

Programs are designed to help customers install more efficient devices and adopt more efficient practices. In both residential and commercial sectors, lighting and cooling end-uses are the primary targets for improvement. In the industrial sector, motors and process heating are widely targeted end-uses. Some examples of the kinds of programs to capture these opportunities include:

- *Energy audits*. Typically, an authorized contractor performs an energy assessment for homes and businesses. They make on-the-spot improvements and, depending on customer's eligibility, provide exclusive money saving rebates on appliances, HVAC systems and insulation.
- *Equipment incentives*. Residential customers receive discounts and rebates on efficient light bulbs and appliances (*e.g.*, refrigerators, freezers, and dishwashers). For commercial customers, there are incentives to bridge the gap between the standard and more efficient lighting, air conditioners, refrigeration, and other kinds of equipment.
- *Financing programs*. Programs may offer customers low-interest loans and financing for energy efficiency improvements, often repaid through extra charges on the individual customers' bills.

What is the process for developing and approving and funding programs?

Each year, the Electric Distribution Companies prepare Conservation and Load Management plans with the advice and assistance of the Connecticut Energy Efficiency Board (chaired by the DEEP Commissioner) and its consultants. To the extent that the programs and requested budgets are approved, the Electric Distribution Companies administer the programs and recover the costs primarily through a special component of customer rates.

How much energy efficiency has Connecticut accomplished already?

Connecticut has been actively implementing energy efficiency programs for many years now. Connecticut's successful record in implementing programs and policies is manifested in the rankings of American Council for an Energy Efficient Economy (ACEEE). ACEEE evaluates each state based on its energy efficiency program spending, energy savings, targets, development of incentives, and removal of barriers (as well as policies, initiatives, *etc.*). According to ACEEE's 2011 State Energy Efficiency Scorecard, Connecticut remained tied for 8th with Minnesota but improved its total score by 5 points from 2010. This IRP examines whether Connecticut should pursue energy efficiency more aggressively.

Evaluation of Expanded Energy Efficiency Resource Scenario

The modeling system described in Figure 3 estimates the effects of resource scenarios on costs, rates, emissions, and in-state jobs. DEEP's analysis of the incremental savings and costs of the Expanded Energy Efficiency scenario revealed substantial benefits in all of these categories relative to the Base Case. As Figure 29 shows, the net cost savings appear modest or negative initially, but then become very substantial. This figure depicts the annual incremental level of program and participant costs in the red bars, which are constant for the three years shown (2015, 2017, and 2022).[45] The green bars indicate the annual incremental gross savings, shown as an offset to the costs. The clear bar indicates net costs if it is above the zero dollar axis and net benefits or savings if it is below the zero dollar axis. Benefits multiply over time because efficiency measures save energy for many years (12 years, on average), and each year's measures build on the measures implemented in prior years.

It is important to clarify several points related to the Expanded Energy Efficiency scenario. First, in 2017, the scenario predicts gross energy savings of approximately $238 million per year compared to the Base Case, a figure which appears to be less than the $243 million incremental costs. However, such a comparison does not recognize the multi-year benefits of the measures.

By 2022, DEEP projects that the Expanded Energy Efficiency scenario would save customers $778 million per year in energy, capacity, and RPS costs compared to the Base Case. At an annual incremental cost of $105 million in program costs and $138 million in participant out-of-pocket costs, customers' annual net savings would be $534 million. The $778 million gross savings can be explained in terms of quantity and price components:

- $425 million of the savings is the direct effect of consuming smaller quantities of costly commodities: $329 million less energy consumed, $56 million less capacity costs incurred, and $40 million less Alternative Compliance Payments. These estimates are derived by multiplying the change in quantity by the original (Base Case) prices.
- $350 million of the customer savings reflects reductions in market prices that would occur in 2022, brought about by lower demands for energy and capacity. $87 million of the savings derives from a $2.9 per MWh reduction in average energy prices, and $263 million in savings results from a $2.4 per kW-month reduction in capacity prices. The capacity price impact is so large because the peak load reduction from energy efficiency forestalls the need for new generation and defers the rise in capacity prices to a level needed to attract new generation into the market.[46]

In subsequent years, under the Expanded Energy Efficiency scenario, customers would continue to save money from the more efficient equipment installed in their homes and businesses. The gross savings would continue until the end of the measure lives (about 12 years on average) even

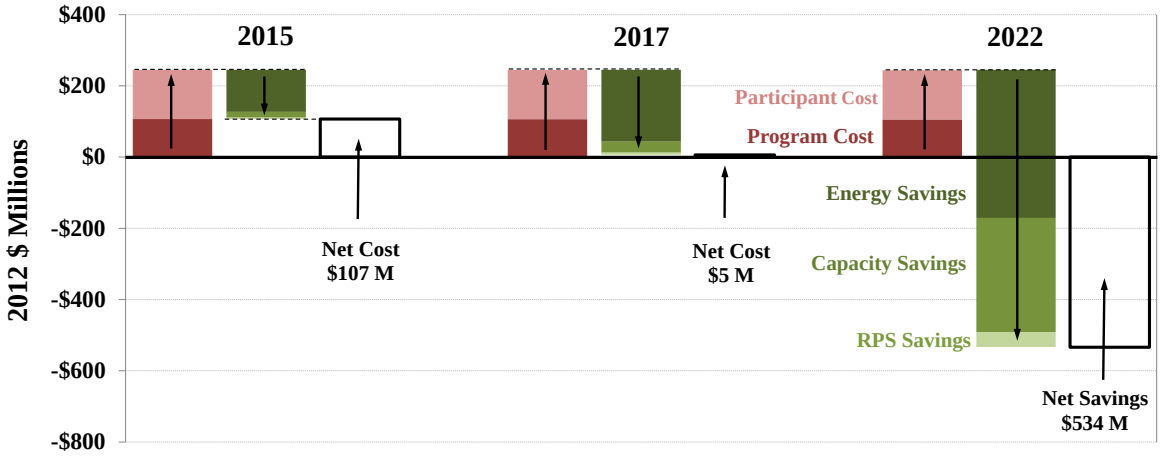
[45] Alternatively, participant costs could be lower initially and higher in later years if some of the measure costs are financed, as contemplated in the Expanded Energy Efficiency scenario.

[46] In the capacity market model, energy efficiency was modeled as a supply-side resource, not a demand reduction, consistent with how energy efficiency participates in ISO-NE's forward capacity auctions.

if no further measures were undertaken.[47] However, it is likely that programs would continue as old measures reach the end of their useful life and as new technologies and practices provide opportunities for new savings not yet envisioned in the Potential Study.

Although savings from energy efficiency measures last several years, the price reduction benefits would be in effect only temporarily until the electric supply side of the market adjusts. Because every dollar customers save due to reduced prices means that suppliers are paid a dollar less for the same product, the Expanded Energy Efficiency scenario may cause suppliers to retire more capacity, delay the construction of new generation, and/or offer capacity into the capacity auction at higher prices. DEEP's IRP modeling system analysis takes these effects into account, at least through 2022. The Expanded Energy Efficiency scenario is projected to cause 547 MW more retirements in 2016, and to delay the entry of new combined-cycle generation from 2022 to 2025 (with 714 MW less in 2025). Thus, the price effects would be expected to significantly diminish after 2022, and even earlier in the Tight Supply and Low Gas futures that need new generation before 2022. Although the price reduction benefits are temporary, it is important to recognize that the customer net savings from Expanded Energy Efficiency are substantially positive even without including price impacts. The Expanded Energy Efficiency scenario would create $425 million in gross savings in 2022, at a cost of $243 million in incremental program and participant costs. The price impacts can be viewed as a supplemental but transient benefit obtained from facilitating the development of low-cost resources.

Figure 29
Incremental Annual Costs and Savings of Expanded Energy Efficiency
(Relative to the Base Case)



[47] Annual benefits might be less than those estimated in 2022 once the supply-demand balance reaches a long-term equilibrium, where generation supply adjusts and there is little wholesale price impact from changes in demand. However, the quantity effects would still apply, with customers benefiting from reduced purchases.

When customers save money on energy expenditures, they can spend that money on other goods and services, which has a major and widespread effect on the Connecticut economy. Based on macroeconomic modeling conducted by the Connecticut Department of Economic and Community Development for this IRP, each $100 million reduction in net customer energy costs is projected to support or create 780 in-state jobs (based on a weighted average of residential, commercial, and industrial sectors). Thus, the annual net savings of $534 million in 2022 would support 4,200 more in-state jobs than in the Base Case for as long as the savings persist. In addition, implementation of the Expanded Energy Efficiency scenario would add 1,500 direct, indirect, and induced jobs. The direct jobs are associated with implementing measures, and the indirect and induced jobs are created in the rest of the economy for each year the program endures. Spending and jobs associated with in-state renewable investments would be reduced by 250, however, because load reductions would be expected to translate into fewer ACP payments. The net result is that the Expanded Energy Efficiency scenario would create 5,500 more in-state jobs per year than in the Base Case.

Overall customer costs, which are the product of rates and the quantity of energy services consumed, ultimately have a greater impact on the economy and on overall consumer well-being than do rates alone. Rates themselves may be important, however, to customers who participate less in energy efficiency programs. Under the Expanded Energy Efficiency scenario, 2017 rates would be 0.21 ¢/kWh higher than the Base Case. Overall rates in 2022 would decrease by 0.60 ¢/kWh, however, as a result of greater capacity and energy price effects.[48]

As explained in more detail in Appendix C, the Expanded Energy Efficiency program unit costs (expressed in $ per 1-yr kWh) are projected to be lower than in the Base Case. DEEP considered the cost and energy savings implications if these lower costs did not materialize and the program costs per kWh saved turned out to be the same as the average Base Case program costs over 11 years. In that case, achieving the full potential would require an additional 0.30 ¢/kWh increase in customer charges to support the programs. Alternatively, if the annual budget were limited to $206 million as assumed for the Expanded Energy Efficiency scenario, fewer savings would occur. The implied annual Expanded Energy Efficiency savings would be 428 GWh and 58 MW, instead of 601 GWh and 125 MW in the Expanded Energy Efficiency scenario described above. While this lower level of capacity savings would not necessitate replacement capacity over this time period (since there are no local or regional resource adequacy needs even in the Base Case), economic benefits would be lower. The reduced economic benefits may be very roughly proportional to the difference in GWh saved (relative to the Base Case) compared to the Expanded Energy Efficiency scenario. In 2022, for example, energy savings relative to the Base Case would be roughly $233 million (compared to $416 million in the Expanded Energy Efficiency scenario); capacity savings would be roughly $98 million (compared to $320 million

[48] The overall impact on rates is the combination of higher program costs offset wholly or in part by the lower generation service charges that reflect energy and capacity prices. In 2017, the Expanded Energy Efficiency scenario requires a 0.37 ¢/kWh increase in program funding, which is only partially offset by lower energy and capacity charges. This analysis does not quantify another related rate impact: reduced energy consumption would slightly increase the rate component necessary to recover fixed transmission and distribution costs; however some future transmission and distribution costs might also be avoided due to lower consumption, partially offsetting this effect.

in the Expanded Energy Efficiency scenario), and net savings would be approximately $191 million (compared to $534 million in the Expanded Energy Efficiency scenario)[49].

If the full cost-effective potential envisioned in the Expanded Energy Efficiency scenario is achieved, emissions would be significantly lower than in the Base Case. In Connecticut, emissions of NOx and SO_2 would decrease by more than 10%. In Connecticut and New England, CO_2 emissions decrease more than 5%. Notably, emissions would also be slightly lower in the Expanded Energy Efficiency scenario than those estimated under a Full Renewables Build-out scenario (described below), which would cost Connecticut customers considerably more than the Expanded Energy Efficiency resource scenario.

Conclusion: Expanded Energy Efficiency

Based on the analysis above, DEEP concludes that the analytical results provide strong support, in terms of widespread economic and environmental benefits, for achieving all cost-effective energy efficiency. To capture this opportunity, DEEP concludes that the state can cost-effectively achieve approximately 2% annual energy savings reduction in energy consumption by increasing the budget for Conservation and Load Management (C&LM) programs from $105 million annually under a business-as-usual budget to $206 million annually, and by initiating complementary measures such as providing low-cost financing, implementing more aggressive codes and standards, and motivating behavioral changes through information and training. Net of all program and participant costs, customers would save $534 million per year by 2022 compared to a business-as-usual base case. The savings arise from reduced consumption of energy, capacity, and renewable credits, and also from reductions in market prices resulting from expanding this low-cost resource.

Accordingly, the expansion of efficiency programs included in the 2012 Conservation and Load Management (C&LM) Plan submitted by the Energy Efficiency Board should be approved as part of a provisional longer-term plan to maintain that level of investment. The C&LM programs should be funded through charges on customers' bills, complemented by continued self-support from capacity credits earned in the forward capacity auctions, and with revenues from CO_2 allowance sales under the Regional Greenhouse Gas Initiative program. The charges on customers' bills can be expected to decline over time as the quantity and price of forward capacity market credits increase.[50]

Achieving the level of potential savings in the Expanded Energy Efficiency scenario will require more than just funding. Under the oversight of DEEP and the Energy Efficiency Board, utilities must continue to develop the innovative components of their programs, especially those components that advance energy conservation opportunities with relatively high non-cost barriers, such as training commercial customers in efficient operating practices. As appropriate,

[49] The emissions and job implications for this scenario can also be roughly estimated by proportionally scaling the Expanded EE scenario emissions and jobs using the difference in energy saved (relative to the Base Case) between the two scenarios. In 2022, the NO_X and SO_X emissions decrease by roughly 8% (compared to 10% in the Expanded EE scenario) and CO_2 emissions decrease by roughly 4% (compared to 5% in the Expanded EE scenario). Similarly, this new scenario would roughly yield 2,200 new in-state jobs (compared to 5,500 jobs in the Expanded EE Scenario).

[50] Another approach that could be considered for adjusting the time profile of rates to better match the time profile of benefits would be to make utility program costs a part of the rate base.

DEEP will propose the adoption of more aggressive codes and standards that can help achieve the desired results without any rate impact. DEEP will work with CEFIA to pursue opportunities that will enable participants to finance measure that will maximize efficiency savings by spreading the initial costs over time. DEEP will also evaluate rate structures that could be used to encourage efficiency while protecting all classes of consumers. These and other approaches are discussed further in Appendix C (Energy Efficiency).

The savings that can be achieved through the Expanded Energy Efficiency strategy will depend on several factors, including assumptions about equipment and practices that are in place today and the cost of improving them. Moreover, actually achieving the potential depends on the ability to enable and motivate participants to change and overcome non-cost barriers. Finally, the level of energy efficiency that is cost-effective, and the cost-effectiveness of particular measures, depends on market conditions. For example, under the High Gas future, saving 4,339 GWh per year under the Expanded Energy Efficiency resource scenario is worth $178 million more per year in 2022 than in the Base future. In the Low Gas future, Expanded Energy Efficiency is worth $403 million less than in the Base future in 2022, but $105 million more than in the Base future in 2017. This is because under the Expanded Energy Efficiency scenario, capacity prices would not rise sufficiently to attract new generation as long as low gas prices continue. In addition, overall customer costs in 2022 are expected to be lower in the Low Gas future compared with the Base Case, regardless of the impact of Expanded Energy Efficiency.

Energy efficiency is a flexible resource because it is pursued incrementally (although rapidly ramping programs up or down can be costly and disruptive). DEEP therefore concludes that energy efficiency programs should be ramped up beginning in 2012, on a trajectory to achieve all cost-effective program spending, but without locking in to a rigid plan. The details can be adjusted over time as updated information about the success of expanded programs becomes available, and about market conditions, technology costs, penetration levels and innovation, federal standards, and non-cost barriers to efficiency. Such information should be gathered through future Conservation and Load Management proceedings, market studies, and updated potential studies.

B. Renewable Portfolio Standard

The Connecticut Renewable Portfolio Standard (RPS) policy was instituted in 1998 in order to reduce reliance on fossil fuels and reduce emissions from the power sector. Since that time, Class I renewable development in New England has grown sufficiently to meet the region's current requirement, with renewable energy credit (REC) prices hovering around $20-$30/MWh during most of the recent year.[51] Looking forward, while the resource potential in the region remains high (particularly for wind power in northern New England), there are many uncertainties regarding the future pace of renewable development. First, substantial additional transmission would be needed to deliver and integrate large additional amounts of remote wind resources. Viable transmission options, their costs, transmission planning processes, and

[51] One renewable energy credit (REC) is created from one MWh of qualifying renewable electricity generated. Electric suppliers in New England can satisfy their RPS obligations by purchasing RECs or making alternative compliance payments. REC revenues supplement energy and capacity revenues received by generators. REC prices climbed to more than $50/MWh as of March 2012, in part owing to uncertainty surrounding Massachusetts' proposed biomass eligibility rules.

transmission cost allocation rules present regional challenges that Connecticut will work with others in the region to address. Second, the adverse financial conditions over the past three years have made it increasingly difficult for new renewable energy resources to secure funding. In addition, federal budgetary issues have compounded the perennial uncertainty regarding the future of federal production tax credits, after the current ones are set to expire at the end of 2012.

In light of Connecticut's continued commitment to reduce emissions from the power sector and diversify its fuel mix, this IRP evaluated and compared two potential future paths to achieving these objectives. The two alternative pathways are:

- **No Change to Existing Class I RPS Requirements.** There are significant uncertainties about the costs and achievability of the Class I requirement. To analyze these uncertainties, three levels of Class I compliance were evaluated: a Low Renewables case with very little additional Class I development; the Base Case, with more than 2,500 MW of projected renewable additions based on extrapolating observed development trends; and a Full Renewables Buildout case in which enough Class I resources (along with necessary transmission expansions) are developed to meet Class I demand in Connecticut and the rest of New England.
- **Modifying the Class I RPS Requirements to Allow Energy Efficiency or Large Hydro to Meet a Portion of the Goal.** Given the increasing costs and uncertainties around meeting Connecticut's expanding Class I RPS target, we evaluated the possibility of achieving the clean energy objectives of RPS Class I requirements with greater emphasis on energy efficiency and/or large, out-of-region hydroelectric resources to meet Connecticut's energy needs.

Evaluation of RPS Scenarios

No Change to Existing Class I RPS Requirements. Under the Base Case, DEEP projects that the region will be short of Class I requirements for year 2018 and beyond, with Connecticut paying high REC prices, Alternative Compliance Payments for substantial REC shortfalls, and a portion of new regional transmission costs as a consequence. From the standpoint of clean energy development, likely customer costs, and in-state job creation, this outcome falls short of the ideal. Under the Base Case, compliance with Class I would reach a cost of $445 million annually by 2022.

Figure 30 compares two alternative development paths for Class I compliance, showing the relative impact of achieving low and full Class I compliance. Under the Low Renewable scenarios, annual customer costs in 2022 are $365 million, which is $80 million lower than the Base Case, with similarly high REC prices and Alternative Compliance Payments but reduced transmission costs associated with reduced wind development. After accounting for the difference in energy and capacity costs (shown in Appendix A), the annual customer costs in 2022 under the Low Renewable scenarios are roughly $100 million lower than the Base Case. This potential scenario, however, represents a failure to achieve the objectives of the RPS, with

customers still paying more than $250 million per year in Alternative Compliance Payments while receiving minimal environmental benefits.[52]

Figure 30. Alternative Renewable Market Outcomes

Scenario	Class I Demand *(GWh)*	Class I Supply *(GWh)*	REC/ACP Price *($/MWh)*	Class I RECs *($Mil)*	Class I ACPs *($Mil)*	Tx for RPS *($Mil)*	CT Renew. Prog. Net of Mrkt. Revs. *($Mil)*	Total RPS Costs *($Mil)*	Emissions Reduction
Full Class I Achieved	20,281	20,281	$17	$115	$0	$179	$92	$385	High
Base Case Class I Achieved	20,281	17,428	$45	$168	$130	$81	$67	$445	Medium
Low Class I Achieved	20,281	13,496	$45	$57	$257	$0	$51	$365	Low

Note: "CT Renew. Prog Net of Mrkt. Revs." reflect the annual payments needed to support in-state Class I programs (Project 150, residential solar PV, ZREC, LREC, and other Class I projects) net of energy, capacity and Class I market revenues.

[52] The ACP revenues were assumed to fund rooftop photovoltaic installations, fuel cells, and other behind-the-meter projects that do not displace as much fossil generation as grid-connected renewables that create RECs.

RENEWABLE PORTFOLIO STANDARDS — THE BASICS

What are Renewable Portfolio Standards?

Renewable Portfolio Standards (RPS) are state-specific policies for requiring a certain portion of the electricity consumed to be sourced from renewable generation or low-emission resources. Connecticut's RPS requires electric suppliers to serve at least 20% of the state's retail load with new wind, solar, fuel cell, landfill gas, small hydro, and biomass resources (called "Class I"), 3% with existing renewable resources (called "Class II"), and 4% with combined heat and power or energy efficiency (called "Class III") by 2020. Maine, Massachusetts, New Hampshire, and Rhode Island also have similar Class I RPS requirements. Failure to meet the requirements results in Alternative Compliance Payment penalties, which Connecticut would use to fund in-state renewable programs.

What renewable resources does Connecticut have?

Although Connecticut has very limited in-state renewable energy resources, it has the potential to build some small-scale wind, solar, fuel cell, hydro and biomass projects. To date, Connecticut has relied on existing resources, largely located outside of Connecticut to meet its Class I RPS requirement. As the magnitude of the Class I requirement grows, Connecticut's purchase of RECs from outside resources will likely continue to increase.

What mechanisms does Connecticut use to develop in-state renewable energy?

Connecticut uses several approaches to support in-state development of Class I resources, including requiring utilities to enter into long-term contracts with projects located on the customer-side of the meter. A *Clean Energy Finance and Investment Authority* (CEFIA) has been established to promote investment in and commercialization of clean energy technologies.

What out-of-state resources are important to Connecticut?

Northern New England, especially Maine, is rich with wind resources. However, a large build-out of wind energy projects in Maine will require significant new transmission investments to integrate and balance that wind power onto the New England grid. Numerous transmission projects have been proposed to help meet regional Class I RPS requirements.

How is renewable energy paid for?

In addition to federal tax credits that help offset the cost of qualified renewable energy projects, producers receive renewable energy credits, "RECs," for every MWh of renewable or clean energy produced. Electric suppliers that need the RECs to satisfy their RPS requirements will buy them from producers at a market price. These payments help producers earn revenues in addition to those from selling the associated power. Connecticut also has several special programs to provide additional financial support for developing in-state projects for which the value of RECs and power alone would be insufficient.

The Full Renewable Buildout scenario shows better results, but would rely on coordinated and timely investment in transmission to support the development of a significant amount of wind power in northern New England. In other words, achieving the Full Renewable Buildout scenario will depend on the favorable resolution of uncertainties around transmission build-out that are not within any single state's direct control. Under the Full Renewables scenario, the region would meet the existing Class I requirement, with REC prices set by the levels required to support the development of onshore wind, which are significantly lower than the Connecticut Alternative Compliance Payment. Transmission costs would be higher under the Full Renewable scenario than in the Base Case. Assuming 25% allocation to Connecticut (based on

its load share in New England) however, these higher transmission costs would be more than offset by the reduced REC prices and the absence of Alternative Compliance Payments.

Overall, the total RPS-related costs in the Full Renewable Buildout scenario would be about $60 million less than in the Base Case. After accounting for market price impacts on energy and capacity, the customer costs would be about $160 million less than in the Base Case, with greater emissions reduction and greater positive employment effects due to lower customer bills than in the Base Case.

With respect to employment impacts, in the Full Renewables scenario, the development of remote generation and transmission would not support many jobs in Connecticut. However, in the Low Renewables scenario, the use of the annual Alternative Compliance Payments of almost $260 million to install in-state renewable projects would support approximately 800 jobs (including associated indirect and induced effects on the broader economy), plus an additional 800 jobs resulting from lower customer costs compared to the Base Case (mostly from not having to pay for as much transmission). The downside of the Low Renewables scenario is that it would still be costly without substantially achieving the environmental objectives of RPS.

By testing different levels of Class I development, these scenarios demonstrate that regional cooperation is critical to ensuring that the necessary transmission is developed, such that sufficient renewable resources can be developed in New England and environmental objectives can be achieved. If the necessary transmission and resources are not developed, Connecticut customers would likely face large Alternative Compliance Payments without fully achieving the RPS objectives.

Modifying the Class I RPS Requirements to Allow Energy Efficiency or Large Hydro to Meet a Portion of the Goal. If complying with Class I RPS requirements increases customer costs significantly, then Connecticut would explore new ways of meeting its clean energy targets. For example, if the region's transmission planning process fails to meet the region's needs for new transmission to access remote renewable resources, it may make sense to allow a broader set of clean resources to attain Connecticut's clean energy objectives. Potential clean energy resources could include new energy efficiency and large hydropower.

To illustrate the potential impacts of using other clean energy resources to meet the needs of Connecticut, we analyzed a policy that would allow up to one quarter of the current Class I requirement to be met through the additional energy efficiency developed under the Expanded Energy Efficiency. Under this policy, energy efficiency that qualifies for Class III RECs could be used to meet a portion of the Class I RPS requirements. However, the energy efficiency would not be paid as a Class I resource.

Allowing up to one quarter of the current Class I requirement to be met through Expanded Energy Efficiency would produce benefits relative to the Base Case. Allowing conservation to meet part of the Class I requirement would save customers $152 million annually by 2022 compared to the Expanded Energy Efficiency scenario. These savings are the result of reducing the quantity of Class I RECs purchased and Alternative Compliance Payments made, and also reducing the Class I REC price from a $45/MWh scarcity level (set by the Alternative Compliance Payment) to an $18/MWh market price set by the long-run marginal net cost of

onshore wind.[53] Another possible means to reduce the Class I RPS costs would be to allow power from large hydroelectric facilities outside of New England to count towards a portion of the Class I RPS requirements.

Conclusions: Renewable Portfolio Standard

Based on the analysis in this IRP, DEEP anticipates a significant challenge ahead in meeting Connecticut's aggressive RPS targets at a reasonable cost. Connecticut, however, is currently meeting its Class I RPS goals and a shortage is not expected until around 2018 under Base Case assumptions. DEEP therefore believes it is not necessary to make any changes to the RPS at this time. DEEP does believe, that in the near term, policy choices must be made with respect to the Class II and Class III REC market to address concerns raised in this IRP.

DEEP has evaluated the costs and risks that Connecticut customers face in complying with the existing RPS Class I requirements. Based on our assessment of the potential environmental benefits and customer costs of different approaches, DEEP concludes that Connecticut must strive to meet the existing Class I RPS requirements by actively engaging in regional efforts to resolve transmission planning and cost allocation issues, to enable further development of the region's renewable resources and implement strategies to reduce costs. DEEP believes that mechanisms such as long-term contracts must be explored to encourage the development of low-cost renewable generation.

DEEP will continue to carefully monitor the progress in the region's renewable resource development. In the next six months, in accordance with Section 129 of Public Act 11-80, DEEP will examine RPS issues in more detail, including other ways to achieve the Class I requirements. This analysis will include using energy efficiency and large hydroelectric resources to meet a portion of the Class I RPS goals. Careful monitoring of overall progress will be important to ensure that efforts to meet the Class I RPS requirements do not unnecessarily increase customer costs in Connecticut. If it appears that complying with the existing Class I RPS requirements will become unnecessarily costly to customers without achieving important clean energy and economic development goals, then DEEP will make recommendations to modify the Class I market. DEEP will also explore whether a large Class I biomass project could improve RPS compliance while yielding benefits to ratepayers.

As part of this forthcoming analysis, DEEP will examine the issues facing in-state resource recovery facilities to develop a long-term plan to ensure that they are able to continue operations. Class II RPS requirements will be reassessed to provide a better supply/demand balance to create more meaningful Class II REC prices to support existing and new Class II projects. DEEP will reconsider whether the RPS provides sufficient incentives for Class II generators, or whether other options, such as purchase power arrangements, are necessary. In the interim, a short-term power purchase agreement may be necessary for some facilities until a longer-term plan can be implemented.

[53] The lower Class I price does not save customers money on net for approximately 1,150 GWh of Class I RECs created by Connecticut-specific ZREC, LREC, Project 150 and Other Class I programs. Reductions in Class I revenues increase the amount of customer support that must be collected through special charges to fund these special programs.

Class III RPS requirements will be also reassessed in order for the state to continue to support combined heat and power and third-party sponsored energy efficiency through the RPS. Since utility-based energy efficiency programs are funded through the Conservation and Load Management program, the Class III Renewable Portfolio Standard could be revised to focus primarily on providing incentives to combined heat and power and third-party energy efficiency programs that do not have a dedicated source of funding. The actual target level and the associated Alternative Compliance Payment and price floor for the Class III RECs need to be reexamined in such a way that the revised policy provides an appropriate and adequate level of support for the resources desired.

C. New Cost-of-Service Generation

The New Cost-of-Service Generation Resource Scenario examines the value to Connecticut customers of building and "owning" a plant before such a resource would have been developed by merchant developers. To analyze this scenario, we assumed the development of a new efficient-scale 656 MW gas-fired combined-cycle plant in Connecticut in 2017, at an overnight cost (excluding interest during construction) of $929/kW (in 2012 dollars). Consistent with our assumptions for generic merchant entrants, we assumed $17/kW-year fixed operations and maintenance costs, but we departed from generic assumptions by using a relatively low 6.7% after-tax weighted-average cost of capital, reflecting the allocation of risk to customers. Customers would pay for the full capital cost plus fixed operating and maintenance costs, following a traditional regulated cost-of-service revenue requirements schedule over an assumed 30-year life of the plant, through the imposition of a non-bypassable charge. They would receive all of the plant's revenues, including any energy margins and capacity revenues.

This analysis did not evaluate a scenario in which capacity is needed but merchant generation is not forthcoming, and the states or ISO-NE solicit capacity as a backstop for meeting reliability needs. Such a scenario was not evaluated because our resource adequacy analysis did not identify a need for new generation over the study horizon. The exceptions are in the "Tight Supply" and "Low Gas" futures, where new generation becomes needed in 2018 in New England, although not in Connecticut specifically. Future IRPs should assess whether those futures are being realized or new generation is needed for any other reason, and whether the market is likely to fail to meet that need.

Evaluation of New Cost-of-Service Generation Resource Scenario

Building new generation always entails assuming risk, but sponsoring a new generation facility well ahead of likely market needs inflates these risks and using a cost-of-service cost recovery model shifts risk onto customers. In addition to the typical risk that any particular plant might not earn enough in the markets to cover its development cost (including a return on investment), recent capacity market rule changes raise the real possibility that a proposed new resource will not qualify for *any* capacity payments during its early years in operation. This likelihood arises from the implementation of the Minimum Offer Price Rule (MOPR), which is a new feature being added to Forward Capacity Markets in order to prevent and mitigate the exercise of buyer market power, i.e., artificially depressing the capacity price by flooding the market with

uneconomic capacity.[54] The details regarding the rule and also the application of the rule to individual market offers have not yet been fully determined. Generally, new generation will have to offer into the forward capacity auction at a competitive (i.e., cost-reflective) price, as if it did not have a state-sponsored contract. A resource being introduced before it would be economic on a competitive basis might not clear the market and thus might not get paid for capacity.

In the most stringent case, the new cost-of-service generation unit that was examined in this scenario would not earn capacity revenues until at least 2023, at which time a new merchant unit also would be competitive. However, it is possible that the unit could clear the capacity market earlier if its lower financing costs are considered in determining its mitigated offer floor, or if it has low unit-specific construction costs. Instead of analyzing every possibility, we evaluated customer benefits under two divergent assumptions: 1) that the unit would receive no capacity revenue (i.e., not clear in the auction based on a relatively high minimum offer price floor) until 2023; and 2) the most optimistic assumption that the minimum offer price floor for this unit somehow would be low enough that the unit would clear the auction and receive capacity revenues immediately upon commencing operation in 2017.

[54] Federal Energy Regulatory Commission, "Order on Paper Hearing and Order on Rehearing," Issued April 13, 2011, 135 FERC ¶ 61,029, Docket No. ER10-787-000.

COST-OF-SERVICE GENERATION — THE BASICS

What is cost-of-service generation?

Most generation in New England is owned by independent power producers, who expect that revenues from wholesale markets including capacity and energy markets will exceed their operating costs and earn them a return on invested capital commensurate with the risks they take. Revenues based on future market prices can be highly variable (i.e., risky) and therefore investors demand relatively high returns. An alternative arrangement is possible, whereby a developer sells the power under a long-term contract with a state agency or utility, with the price of that power reflecting the all-in costs of building and operating the plant, net of all revenues received. The purchaser then recovers the power costs from customers. By guaranteeing a revenue stream that covers capital and net operating costs, the contract essentially shifts market risks and rewards to customers; revenue predictability reduces development risk and enables lower cost financing. These contracts mimic traditional "cost-of-service" regulation where utilities build power plants based on assurances that prudently-incurred costs (including reasonable payments to debt and equity) will be recovered in regulated rates.

How does cost-of-service generation fit into wholesale and retail markets?

Cost-of-service contracts enable the introduction of specific resources into the wholesale power market that private developers otherwise might not provide. These resources may be sought for reliability enhancements (capacity value or quick-start reserve capability); to meet fuel diversity or risk hedging objectives; or to foster particular technologies (solar, fuel cells). In restructured retail markets such as Connecticut, contractual terms and rate recovery details have to recognize that utilities do not own generation or have captive load to serve. The costs of such long-term contracts are typically recovered through non-bypassable charges that appear on all customer bills, regardless of their choice of retail energy supplier. Using non-bypassable charges spreads the costs across all customers and avoids the situation where cost recovery falls on specific suppliers who customers might drop because the charges (especially in the initial years of cost recovery) are above-market compared to other suppliers.

Does Connecticut have any cost of service generation or similar arrangements?

There are several examples of cost-of-service generation and other similar arrangements in Connecticut. Over the past few years, the state has sponsored the development of 506 MW of combustion turbine projects to help meet quick-start reserve requirements in Connecticut, through cost-of-service agreements. In other cases, the state has sponsored or required the use of long-term contracts coupled with non-bypassable customer surcharges — although none has used the cost-of-service model discussed here. For example, capacity from the Kleen project (a 620 MW combined cycle plant that began operating in 2011) is procured under a long-term contract, and long-term contracts support the development of specific in-state renewable projects under the Project 150 program.

For simplicity, Figure 31 shows the annual costs and direct benefits to customers only for the Base future with the more stringent Minimum Offer Price Rule capacity revenue assumption. The figure shows that regulated revenue requirements would be initially much higher than the energy margins the unit would receive, while capacity revenues are unavailable until 2023. When the capacity revenues appear in 2023, overall market revenues would exceed the assumed cost-of-service revenue requirements paid by the customer-owners, for two reasons: (1) capacity market revenues at that point would be assumed to be determined by a merchant generator, which has higher financing costs due to higher rates paid to debt and equity holders and a shorter amortization period; and (2) the cost-of-service revenue requirements would have declined with depreciation. However, the net benefits after 2023 would not outweigh the initial net costs in present value terms until 2035, as shown in the left half of Figure 33.

The overall value to customers appears more positive if energy price reduction benefits are included. Building an efficient combined-cycle plant in advance of the time of need reduces energy prices by $1.6 to $2.1/MWh between 2017 and 2022, until the capacity would have presumably been built anyway in 2023. Including the resulting $49–66 million of annual benefits suggests a more positive proposition for customers. On a cumulative NPV basis, it would still be more costly than doing nothing until 2022, as shown by the dotted curve in Figure 31.[55] These figures do not show the (slightly greater) value available if a lower minimum offer price is accepted and the unit clears earlier when capacity prices are still low. The results of this case and all others analyzed are shown in Appendix A (Detailed Tables).

The right half of Figure 32 shows the value of waiting to build the unit in 2020, closer to the time when New England will need capacity (although not in Connecticut specifically). The net cost is considerably lower compared to building in 2017, with six fewer years until breakeven on an NPV basis. Although there are also fewer years of energy price reductions between the time the plant is built and when a similar plant might have been built otherwise, the overall profile is still more favorable than building in 2017. In fact, including energy price reduction benefits (the dotted line) shows that the unit might break even on a cumulative NPV basis almost immediately upon operation in 2020.

Regarding emissions, building an efficient gas-fired plant in Connecticut would reduce New England emissions of NOx, SO_2, and CO_2. However, with the additional local generation, Connecticut's in-state NOx emissions would increase by several percent for the summer and annually, with a slight reduction in NOx emissions on High Energy Demand Days as the new plant displaces some less efficient, higher-emitting generation. The emissions savings could be greater if somehow the new generation plant could be part of a package agreement to close a high-emitting existing generator that otherwise would not retire.

Developing a 656 MW combined-cycle plant would create 2,700 jobs during the two-year construction period, followed by 100 ongoing jobs over the life of the plant. All jobs estimates include direct, indirect and induced effects of the project on in-state employment. Unlike the Expanded EE scenario, we have not quantified additional employment benefits associated with customers' energy savings because customer costs rates would be higher initially. With COS rates, Connecticut customers' estimated net savings would be only slightly positive by 2022, even when accounting for LMP impacts. Thereafter, estimated net savings would increase as COS rates decrease over time.

[55] "Cumulative NPV" is defined as the sum of all prior year's cash flows, with each year's cash flows discounted to a 2017 value, and then expressed in 2012 real dollars.

Conclusion: New Cost-of-Service Generation

This analysis of resource adequacy needs indicates that new generation is not needed in New England until 2022 or later, and not needed specifically in Connecticut until much later. The economics of building cost-of-service generation ahead of need suggests some potential benefits, although nothing strongly positive. Given these findings, and barring any unforeseen circumstances that would necessitate an amendment to this IRP, DEEP concludes that no action should be taken until closer to a time of need. DEEP will reconsider in the next IRP (2014-2015) whether there is a need to sponsor new generation, based on updated information on market conditions at that time.

Figure 31
Annual Costs and Revenues of a 656 MW, $929/kW Cost-of-Service Combined-Cycle Plant
(2012 $Mil)

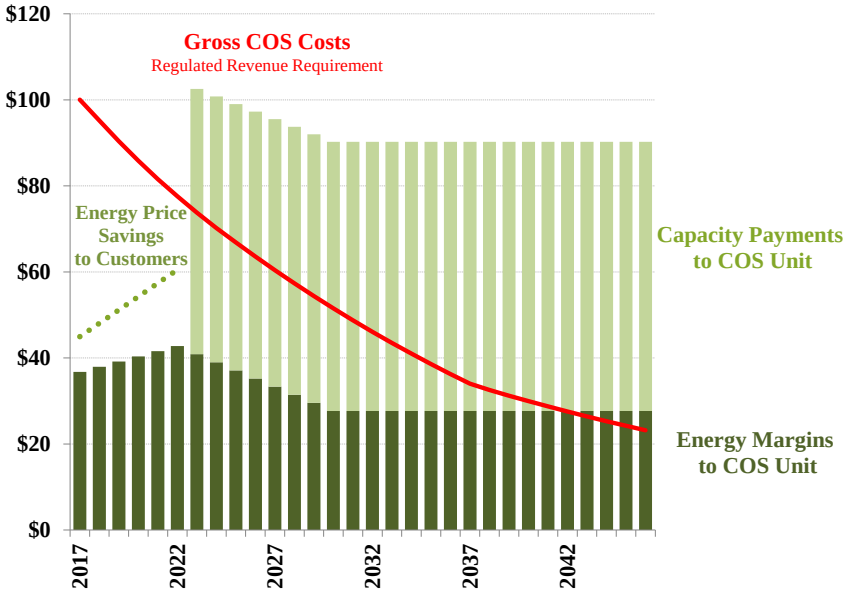
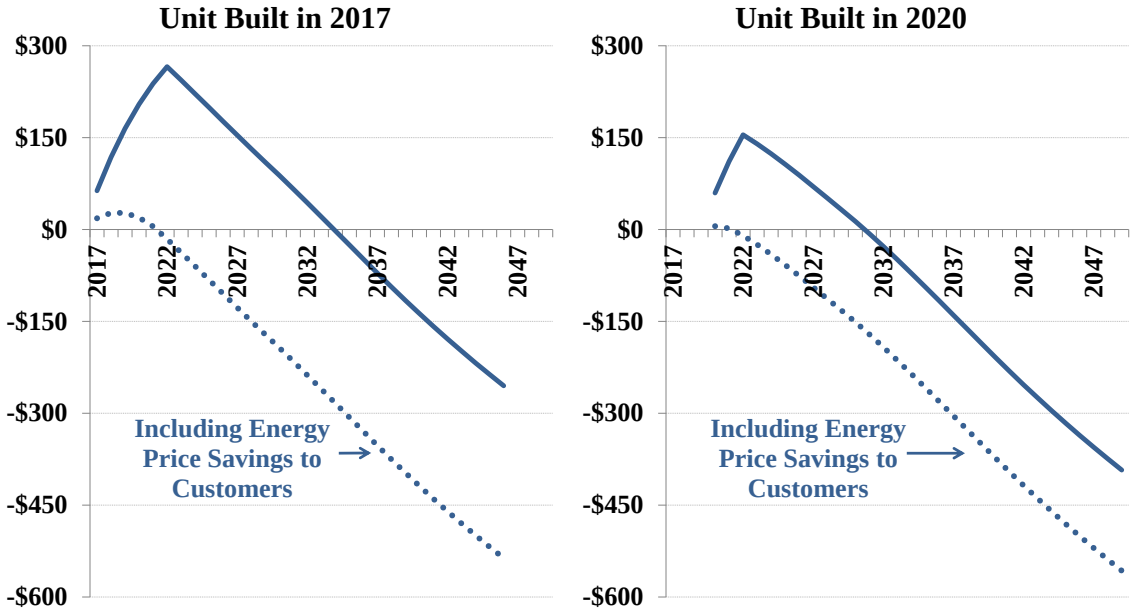


Figure 32
Cumulative NPV of the Costs of a COS Plant (2012 $Mil)



D. Transmission

Section 90 of PA 11-80 requires DEEP, as part of its development of the IRP, to consider Non-Transmission Alternatives (NTAs). Because there are no transmission enhancements to the Base Case being considered in this IRP, no NTAs were evaluated. Appendix G (Transmission Planning) does address the identification and evaluation of NTAs generally. As discussed there, ISO-NE is currently developing an NTA process, and the State of Connecticut should be engaged in that development. This will be especially important over the next year when the ISO will conduct a reliability needs analysis including consideration of NTAs for central Connecticut and Hartford.

Appendix G also describes identified transmission reliability needs and ongoing studies in Connecticut, particularly in southwest Connecticut and central Connecticut. It also summarizes emerging issues affecting transmission planning.

E. Emerging Technologies

For this IRP, DEEP assessed emerging technologies that may provide attractive energy resource options in the coming decade and beyond, even if they are not yet developed enough to play a major role in the current market. Five technologies of interest to stakeholders in Connecticut's resource planning process are: plug-in electric vehicles (PEVs), advanced metering infrastructure (AMI), energy storage, advanced waste-to-energy, and geothermal energy. For each technology, we identified current trends, the potential for the technology to play a role in Connecticut's portfolio of energy resource options in the coming decade and beyond, and state-level activities that could help enable further adoption. Findings and recommendations are explained in Appendix H (Emerging Technology) and summarized below.

Plug-in Electric Vehicles. Connecticut's Electric Vehicle Infrastructure Council and the Electric Distribution Companies collectively are preparing the state for rapid and seamless integration of Plug-in Electric Vehicles (PEVs) into the market. In 2011, the Electric Power Research Institute (EPRI) developed projections for Connecticut, which estimate that the new vehicle market penetration of PEVs may reach 7% by 2020 and 16% by 2030 under a medium market penetration scenario. Based on these current trends, the impacts on the generation system and peak demand should be manageable for Connecticut's Electric Distribution Companies, especially if the charging load can be managed with time-varying rates enabled by user-friendly charging technology. However, coincident charging may create problems for local distribution systems, especially if the PEVs cluster in certain locations. For these reasons, it is important that Connecticut adopt a proactive approach to the deployment of PEVs, and address near-term localized impacts. State initiatives and pilot programs should be used to provide insight into customer charging profiles and whether time-based rates influence that behavior. In addition, the State will work with the private sector to help develop an initial charging infrastructure.

Advanced Metering Infrastructure (AMI). AMI deployments are projected to ramp up across the United States over the coming decade, with half of all households expected to be equipped with a smart meter by as early as 2015. In Connecticut, market penetration of AMI is likely to happen at a more gradual rate. The United Illuminating Company has recently upgraded its remote meter reading and billing capability and is deploying advanced meters to its customer base cost effectively. The Public Utility Regulatory Authority deferred approving Connecticut Light & Power's AMI proposal due largely to uncertainty around the technology and its benefits. As such, the impact of AMI in Connecticut is expected to be modest over the next ten years. Possible state policy options for addressing AMI-related concerns and moving forward with deployment for CL&P include an update on progress in reaching universal industry metering standards and protocols, evaluation of a specific meter technology proposal and a more phased-in implementation plan that takes into account impacts on various customer classes.

Energy Storage. While certain forms of energy storage (such as pumped hydro) have existed in the United States for nearly a century, growing concern over renewables integration has led to an increasing interest in emerging bulk and distributed storage technologies. Currently, these new technologies are typically too costly to be economically competitive with other resources, except in limited applications. However, a significant amount of federal funding has been made available to advance the state of the technology and reduce costs. Whether this will significantly change the economics over the coming decade remains uncertain. Aside from financial incentives, state level activities to promote adoption could include modifications to the regulatory framework, utility planning processes, and market rules to more fully recognize the multi-dimensional benefits that energy storage provides.

Advanced Waste-to-Energy (AWE). Connecticut is the nation's leader in converting trash to energy through the traditional incineration process. New types of AWE, such as anaerobic digestion, would achieve similar benefits with less environmental impact. As of yet, these projects are challenging in terms of commercial viability and therefore likely to proceed on a quite limited basis. Future state activities to promote development of the technology will focus on small-scale demonstration projects or other related research. For example, Connecticut's Clean Energy Finance and Investment Authority (CEFIA) is establishing a pilot program

pursuant to legislation (P.A. 11-80, Section 103(b)) to test the use of anaerobic digestion on organic waste to produce electricity and heat.

Geothermal Energy. Although there is more than 3 GW of geothermal capacity in the United States, with another 800 MW scheduled to come online in the next few years, all of this capacity is located in the Western U.S. Studies have found that geothermal potential in Connecticut (and all of New England) is quite poor. Activities to promote geothermal development in Connecticut would need to focus on developing innovative drilling, power conversion, and reservoir technologies that are more effective and available at much lower costs. Such research already is happening to a limited degree in Connecticut through DOE grants.

Microgrids. While the State, to date, has taken a gradual regulatory approach to the deployment of smart grid technology, the two storms of 2011 revealed vulnerabilities in the state's current electricity system that must be addressed in planning for the state's electric future. The ability to ensure the operation of critical infrastructure during an emergency with a strategic deployment of clean distributed resources that can be isolated from the larger grid in the case of outages would require the use of smart-grid technologies. While recognizing the financial, regulatory, and operational challenges of using distributed generation (DG) resources within micro-grids to increase the resiliency of our electric infrastructure, the potential opportunity to significantly alleviate the pain, disruption, and economic loss caused by prolonged power outages warrants an analysis to evaluate and develop a targeted deployment strategy for micro-grids. To that end, DEEP will continue to investigate the deployment and funding of smart grid technology to support micro-grids as a part of a larger overall strategy on resiliency.

Conclusion: Emerging Technologies

Pursuant to Governor Malloy's Two Storm Panel Review and ongoing efforts for Connecticut to address storm disaster preparedness and recovery, DEEP will undertake a pilot program for the deployment and funding of distributed generation and microgrids, combined with smart grid technology at critical facilities (such as hospitals, prisons, and sewage treatment plants) and in city centers, as well as the use of energy improvement districts as a mechanism to support microgrids.

F. Other Issues

Although the IRP identified no likely resource need in the near-term, DEEP will continue to monitor resource supplies, including the retirement of existing generation, the effect of energy efficiency on electricity demand, and the progress of the NEEWS transmission project. DEEP will also work with ISO-NE to ensure that its market structures provide proper incentives to retain and develop new resources when and where needed. DEEP will work with ISO-NE to maintain reliability during winter cold snaps, when natural gas availability for generation is lowest.

VII. CONCLUSION

The 2012 Integrated Resource Plan (IRP) for Connecticut presents a comprehensive plan for improving Connecticut's electric energy future. The analysis performed for the IRP supports this

plan, which includes a sustained commitment to expanded energy efficiency, further analysis of Renewable Portfolio Standard issues, careful monitoring of resource supplies, deployment of microgrids through a pilot program, and other steps outlined above. This plan will help Connecticut customers reduce the volume of consumption and, thus, save money when market-wide cost factors pressure rates; facilitate the development of low-cost, clean energy resources that are economic but may face barriers to implementation; find cost-effective ways to meet the clean energy objectives of the renewable targets; and support in-state jobs.

APPENDIX A

DETAILED TABLES

Figure 1
Summary of Key Parameters in Connecticut

Future	Resource Scenario	Year	Average Henry Hub Gas Price ($/MMBtu)	CT Load LMP ($/MWh)	Capacity Price ($/kW-mo)	REC/ACP Price (ACP Italicized) ($/MWh)	CT LSEs' ICR (does not deduct EE) (MW)	Energy Requirement net of EE (MWh)	ISO-NE NICR (MW)	ISO-NE DR (MW)	ISO-NE Retired Capacity (MW)	ISO Generic Builds (MW)
Base Case	**Base**	**2015**	**5.2**	**57**	**3.3**	**22.5**	**8,719**	**32,634,377**	**33,618**	**1,502**	**2,801**	**0**
Tight Supply	Base	2015	5.2	60	3.3	19.7	8,917	35,157,377	34,499	1,382	2,669	**0**
Abundant Supply	Base	2015	5.2	54	3.3	25.7	8,519	30,106,376	32,737	1,460	2,724	**0**
High Gas	Base	2015	8.3	75	3.3	7.0	8,307	29,372,396	32,018	1,426	2,801	**0**
Low Gas	Base	2015	3.1	47	3.3	33.5	8,994	34,809,031	34,683	1,552	2,812	**0**
Base Case	**Base**	**2017**	**5.4**	**59**	**1.3**	**23.0**	**8,925**	**33,234,377**	**34,483**	**591**	**3,236**	**0**
Tight Supply	Base	2017	5.4	64	1.1	*50.0*	9,168	36,248,376	35,558	1,382	2,671	**0**
Abundant Supply	Base	2017	5.4	56	1.1	26.7	8,675	30,225,377	33,414	532	4,251	**0**
High Gas	Base	2017	8.6	77	1.0	7.0	8,501	29,893,747	32,842	391	4,354	**0**
Low Gas	Base	2017	3.2	49	2.9	*50.0*	9,208	35,462,115	35,578	1,257	2,812	**0**
Base Case	**Base**	**2022**	**5.9**	**65**	**7.1**	*45.4*	**9,346**	**34,584,361**	**36,424**	**1,988**	**3,236**	**0**
Tight Supply	Base	2022	5.9	65	6.9	*45.4*	9,697	38,252,730	37,912	1,382	2,669	**2,100**
Abundant Supply	Base	2022	5.9	61	5.7	*45.4*	9,015	30,904,830	34,979	1,633	4,251	**0**
High Gas	Base	2022	9.5	84	4.9	*45.4*	8,876	31,072,357	34,607	1,413	4,354	**0**
Low Gas	Base	2022	3.6	52	5.2	*45.4*	9,626	36,925,968	37,506	1,688	2,812	**800**
Base Case	Expanded EE	2015	5.2	57	3.3	22.8	8,719	30,998,698	33,618	1,502	2,801	**0**
Base Case	Expanded EE	2017	5.4	58	1.1	24.0	8,925	30,746,835	34,483	554	3,783	**0**
Tight Supply	Expanded EE	2017	5.4	62	0.6	*50.0*	9,168	33,760,835	35,558	1,382	3,374	**0**
Abundant Supply	Expanded EE	2017	5.4	55	1.0	27.2	8,675	27,737,835	33,414	426	4,725	**0**
High Gas	Expanded EE	2017	8.6	76	1.0	7.6	8,501	27,406,206	32,842	391	5,132	**0**
Low Gas	Expanded EE	2017	3.2	48	2.1	34.4	9,208	32,974,573	35,578	1,061	3,195	**0**
Base Case	Expanded EE	2022	5.9	62	4.7	*45.4*	9,346	29,898,132	36,424	1,492	3,783	**0**
Tight Supply	Expanded EE	2022	5.9	65	6.6	*45.4*	9,697	33,566,502	37,912	1,382	2,671	**1,000**
Abundant Supply	Expanded EE	2022	5.9	59	2.7	22.8	9,015	26,218,601	34,979	937	4,725	**0**
High Gas	Expanded EE	2022	9.5	82	2.9	1.3	8,876	26,386,128	34,607	972	5,132	**0**
Low Gas	Expanded EE	2022	3.6	51	5.5	*45.4*	9,626	32,239,739	37,506	1,757	3,195	**300**
Base Case	Exp. EE & Class I Flex.	2017	5.4	58	1.1	24.0	8,925	30,746,835	34,483	554	3,783	**0**
Tight Supply	Exp. EE & Class I Flex.	2017	5.4	62	0.6	20.7	9,168	33,760,835	35,558	1,382	3,374	**0**
Abundant Supply	Exp. EE & Class I Flex.	2017	5.4	55	1.0	27.2	8,675	27,737,835	33,414	426	4,725	**0**
High Gas	Exp. EE & Class I Flex.	2017	8.6	76	1.0	7.6	8,501	27,406,206	32,842	391	5,132	**0**
Low Gas	Exp. EE & Class I Flex.	2017	3.2	48	2.1	34.4	9,208	32,974,573	35,578	1,061	3,195	**0**
Base Case	Exp. EE & Class I Flex.	2022	5.9	62	4.7	17.9	9,346	29,898,132	36,424	1,492	3,783	**0**
Tight Supply	Exp. EE & Class I Flex.	2022	5.9	65	6.6	*45.4*	9,697	33,566,502	37,912	1,382	2,671	**1,000**
Abundant Supply	Exp. EE & Class I Flex.	2022	5.9	59	2.7	22.8	9,015	26,218,601	34,979	937	4,725	**0**
High Gas	Exp. EE & Class I Flex.	2022	9.5	82	2.9	1.3	8,876	26,386,128	34,607	972	5,132	**0**
Low Gas	Exp. EE & Class I Flex.	2022	3.6	51	5.5	*45.4*	9,626	32,239,739	37,506	1,757	3,195	**300**
Base Case	Full RPS Class I	2022	5.9	64	6.4	17.5	9,346	34,584,361	36,424	1,911	3,236	**0**
Tight Supply	Full RPS Class I	2022	5.9	65	7.0	19.2	9,697	38,252,730	37,912	1,382	2,669	**1,800**
Abundant Supply	Full RPS Class I	2022	5.9	61	5.2	20.7	9,015	30,904,830	34,979	1,565	4,251	**0**
High Gas	Full RPS Class I	2022	9.5	84	4.4	0.0	8,876	31,072,357	34,607	1,299	4,354	**0**
Low Gas	Full RPS Class I	2022	3.6	51	5.7	33.1	9,626	36,925,968	37,506	1,815	2,812	**800**
Base Case	Low RPS Class I	2022	5.9	66	6.4	*45.4*	9,346	34,584,361	36,424	1,918	2,801	**0**
Tight Supply	Low RPS Class I	2022	5.9	66	6.7	*45.4*	9,697	38,252,730	37,912	1,382	2,669	**2,400**
Abundant Supply	Low RPS Class I	2022	5.9	61	4.8	*45.4*	9,015	30,904,830	34,979	1,429	3,706	**0**
High Gas	Low RPS Class I	2022	9.5	85	3.3	*45.4*	8,876	31,072,357	34,607	1,062	3,783	**0**
Low Gas	Low RPS Class I	2022	3.6	53	4.7	*45.4*	9,626	36,925,968	37,506	1,538	2,405	**1,000**
Base Case	New COS Gen, Hi MOP	2017	5.4	58	1.2	24.0	8,925	33,234,377	34,483	532	3,236	**650**
Tight Supply	New COS Gen, Hi MOP	2017	5.4	62	1.1	*50.0*	9,168	36,248,376	35,558	1,382	2,671	**650**
Abundant Supply	New COS Gen, Hi MOP	2017	5.4	54	1.1	27.4	8,675	30,225,377	33,414	515	4,251	**650**
High Gas	New COS Gen, Hi MOP	2017	8.6	76	1.0	7.7	8,501	29,893,747	32,842	391	4,354	**650**
Low Gas	New COS Gen, Hi MOP	2017	3.2	47	2.9	*50.0*	9,208	35,462,115	35,578	1,253	2,788	**650**
Base Case	New COS Gen, Hi MOP	2022	5.9	63	7.1	*45.4*	9,346	34,584,361	36,424	2,058	3,236	**650**
Tight Supply	New COS Gen, Hi MOP	2022	5.9	64	7.3	*45.4*	9,697	38,252,730	37,912	1,382	2,669	**2,150**
Abundant Supply	New COS Gen, Hi MOP	2022	5.9	59	5.7	*45.4*	9,015	30,904,830	34,979	1,633	4,251	**650**
High Gas	New COS Gen, Hi MOP	2022	9.5	82	4.9	*45.4*	8,876	31,072,357	34,607	1,413	4,354	**650**
Low Gas	New COS Gen, Hi MOP	2022	3.6	51	5.4	*45.4*	9,626	36,925,968	37,506	1,688	2,788	**1,150**
Base Case	New COS Gen, Lo MOP	2017	5.4	58	0.9	24.2	8,925	33,234,377	34,483	483	3,783	**650**
Tight Supply	New COS Gen, Lo MOP	2017	5.4	62	0.6	*50.0*	9,168	36,248,376	35,558	1,382	3,374	**650**
Abundant Supply	New COS Gen, Lo MOP	2017	5.4	54	0.9	27.6	8,675	30,225,377	33,414	399	4,725	**650**
High Gas	New COS Gen, Lo MOP	2017	8.6	76	0.7	7.9	8,501	29,893,747	32,842	0	4,802	**650**
Low Gas	New COS Gen, Lo MOP	2017	3.2	47	1.3	*50.0*	9,208	35,462,115	35,578	583	2,788	**650**
Base Case	New COS Gen, Lo MOP	2022	5.9	63	6.6	*45.4*	9,346	34,584,361	36,424	1,968	3,783	**650**
Tight Supply	New COS Gen, Lo MOP	2022	5.9	64	7.3	*45.4*	9,697	38,252,730	37,912	1,382	2,669	**2,150**
Abundant Supply	New COS Gen, Lo MOP	2022	5.9	59	4.8	*45.4*	9,015	30,904,830	34,979	1,443	4,725	**650**
High Gas	New COS Gen, Lo MOP	2022	9.5	82	3.7	*45.4*	8,876	31,072,357	34,607	1,149	4,802	**650**
Low Gas	New COS Gen, Lo MOP	2022	3.6	51	5.5	*45.4*	9,626	36,925,968	37,506	1,688	2,788	**950**

Figure 2
Summary of Key Parameters in Connecticut, Differences Relative to Base Case

Scenario	Strategy	Year	Average Henry Hub Gas Price ($/MMBtu)	CT Load LMP ($/MWh)	Capacity Price ($/kW-mo)	REC/ACP Price (ACP Italicized) ($/MWh)	CT LSEs' ICR (does not deduct EE) (MW)	Energy Requirement net of EE (MWh)	ISO-NE NICR (MW)	ISO-NE DR (MW)	ISO-NE Retired Capacity (MW)	ISO Generic Builds (MW)	ISO Generic Builds (Absolute) (MW)
(DIFFERENCES IN OTHER RESOURCE SCENARIOS COMPARED TO BASE SCENARIO)													
Base Case	Expanded EE	2015	0	(0.6)	0.0	0	(0)	(1,635,679)	0	0	0	0	*0*
Base Case	Expanded EE	2017	0	(1.4)	(0.2)	1	(0)	(2,487,542)	0	(37)	547	0	*0*
Tight Supply	Expanded EE	2017	0	(1.8)	(0.5)	0	(0)	(2,487,541)	0	0	703	0	*0*
Abundant Supply	Expanded EE	2017	0	(0.9)	(0.1)	0	(0)	(2,487,542)	0	(106)	474	0	*0*
High Gas	Expanded EE	2017	0	(0.7)	0.0	1	(0)	(2,487,542)	0	0	778	0	*0*
Low Gas	Expanded EE	2017	0	(1.3)	(0.8)	(16)	(0)	(2,487,542)	0	(196)	383	0	*0*
Base Case	Expanded EE	2022	0	(2.9)	(2.4)	0	0	(4,686,229)	0	(496)	547	0	*0*
Tight Supply	Expanded EE	2022	0	0.4	(0.4)	0	0	(4,686,228)	0	0	2	(1,100)	*1,000*
Abundant Supply	Expanded EE	2022	0	(2.2)	(2.9)	(23)	0	(4,686,229)	0	(696)	474	0	*0*
High Gas	Expanded EE	2022	0	(2.5)	(2.0)	(44)	(0)	(4,686,229)	0	(441)	778	0	*0*
Low Gas	Expanded EE	2022	0	(0.9)	0.3	0	0	(4,686,229)	0	69	383	(500)	*300*
Base Case	Exp. EE & Class I Flex.	2017	0	(1.4)	(0.2)	1	(0)	(2,487,542)	0	(37)	547	0	*0*
Tight Supply	Exp. EE & Class I Flex.	2017	0	(1.8)	(0.5)	(29)	(0)	(2,487,541)	0	0	703	0	*0*
Abundant Supply	Exp. EE & Class I Flex.	2017	0	(0.9)	(0.1)	0	(0)	(2,487,542)	0	(106)	474	0	*0*
High Gas	Exp. EE & Class I Flex.	2017	0	(0.7)	0.0	1	(0)	(2,487,542)	0	0	778	0	*0*
Low Gas	Exp. EE & Class I Flex.	2017	0	(1.3)	(0.8)	(16)	(0)	(2,487,542)	0	(196)	383	0	*0*
Base Case	Exp. EE & Class I Flex.	2022	0	(2.9)	(2.4)	(27)	0	(4,686,229)	0	(496)	547	0	*0*
Tight Supply	Exp. EE & Class I Flex.	2022	0	0.4	(0.4)	0	0	(4,686,228)	0	0	2	(1,100)	*1,000*
Abundant Supply	Exp. EE & Class I Flex.	2022	0	(2.2)	(2.9)	(23)	0	(4,686,229)	0	(696)	474	0	*0*
High Gas	Exp. EE & Class I Flex.	2022	0	(2.5)	(2.0)	(44)	(0)	(4,686,229)	0	(441)	778	0	*0*
Low Gas	Exp. EE & Class I Flex.	2022	0	(0.9)	0.3	0	0	(4,686,229)	0	69	383	(500)	*300*
Base Case	Full RPS Class I	2022	0	(0.9)	(0.6)	(28)	0	0	0	(77)	0	0	*0*
Tight Supply	Full RPS Class I	2022	0	(0.2)	0.1	(26)	0	0	0	0	0	(300)	*1,800*
Abundant Supply	Full RPS Class I	2022	0	(0.2)	(0.4)	(25)	0	0	0	(68)	0	0	*0*
High Gas	Full RPS Class I	2022	0	(0.4)	(0.6)	(45)	0	0	0	(115)	0	0	*0*
Low Gas	Full RPS Class I	2022	0	(1.1)	0.5	(12)	0	0	0	127	0	0	*800*
Base Case	Low RPS Class I	2022	0	1.2	(0.6)	0	0	0	0	(70)	(435)	0	*0*
Tight Supply	Low RPS Class I	2022	0	0.5	(0.3)	0	0	0	0	0	0	300	*2,400*
Abundant Supply	Low RPS Class I	2022	0	0.7	(0.8)	0	0	0	0	(203)	(545)	0	*0*
High Gas	Low RPS Class I	2022	0	1.1	(1.6)	0	0	0	0	(352)	(571)	0	*0*
Low Gas	Low RPS Class I	2022	0	1.1	(0.5)	0	0	0	0	(150)	(407)	200	*1,000*
Base Case	New COS Gen, Hi MOP	2017	0	(1.6)	(0.1)	1	0	0	0	(59)	0	650	*650*
Tight Supply	New COS Gen, Hi MOP	2017	0	(2.5)	0.0	0	0	0	0	0	0	650	*650*
Abundant Supply	New COS Gen, Hi MOP	2017	0	(1.3)	0.0	1	0	0	0	(17)	0	650	*650*
High Gas	New COS Gen, Hi MOP	2017	0	(1.1)	0.0	1	0	0	0	0	0	650	*650*
Low Gas	New COS Gen, Hi MOP	2017	0	(2.7)	(0.0)	0	0	0	0	(4)	(24)	650	*650*
Base Case	New COS Gen, Hi MOP	2022	0	(2.1)	0.0	0	0	0	0	69	0	650	*650*
Tight Supply	New COS Gen, Hi MOP	2022	0	(0.7)	0.3	0	0	0	0	0	0	50	*2,150*
Abundant Supply	New COS Gen, Hi MOP	2022	0	(1.6)	0.0	0	0	0	0	0	0	650	*650*
High Gas	New COS Gen, Hi MOP	2022	0	(1.7)	0.0	0	0	0	0	0	0	650	*650*
Low Gas	New COS Gen, Hi MOP	2022	0	(0.5)	0.2	0	0	0	0	0	(24)	350	*1,150*
Base Case	New COS Gen, Lo MOP	2017	0	(1.6)	(0.3)	1	0	0	0	(108)	547	650	*650*
Tight Supply	New COS Gen, Lo MOP	2017	0	(2.5)	(0.5)	0	0	0	0	0	703	650	*650*
Abundant Supply	New COS Gen, Lo MOP	2017	0	(1.3)	(0.2)	1	0	0	0	(133)	474	650	*650*
High Gas	New COS Gen, Lo MOP	2017	0	(1.1)	(0.3)	1	0	0	0	(391)	448	650	*650*
Low Gas	New COS Gen, Lo MOP	2017	0	(2.7)	(1.6)	0	0	0	0	(674)	(24)	650	*650*
Base Case	New COS Gen, Lo MOP	2022	0	(1.9)	(0.4)	0	0	0	0	(20)	547	650	*650*
Tight Supply	New COS Gen, Lo MOP	2022	0	(0.7)	0.3	0	0	0	0	0	0	50	*2,150*
Abundant Supply	New COS Gen, Lo MOP	2022	0	(1.5)	(0.8)	0	0	0	0	(189)	474	650	*650*
High Gas	New COS Gen, Lo MOP	2022	0	(1.6)	(1.3)	0	0	0	0	(265)	448	650	*650*
Low Gas	New COS Gen, Lo MOP	2022	0	(0.5)	0.2	0	0	0	0	0	(24)	150	*950*

Figure 3
Connecticut Power Supply-Related Costs

Future	Resource Scenario	Year	Energy Cost ($Mil)	Capacity Cost ($Mil)	Class I ACP Cost ($Mil)	Class I REC Cost ($Mil)	Class III ($Mil)	**TOTAL GENERATION SVC COST** ($Mil)	**AVERAGE GENERATION SVC COST** (¢/kWh)	EE FCM Credit ($Mil)	C&LM Charges for Efficiency Programs ($Mil)	Tx Cost for RPS ($Mil)	Renew. Prog. Net of Mrkt. Revs. ($Mil)	Net Cost of New COS Generation ($Mil)	**AVG COST** (¢/kWh)	**Retail Load** (MWh)	**TOTAL COST** ($Mil)
Base Case	Base	2015	1,999	340	0	87	12	**2,439**	**8.04**	-5	86	0	47	0	**8.48**	30,347,606	**2,572**
Tight Supply	Base	2015	2,282	348	0	82	13	**2,725**	**8.33**	-5	86	0	48	0	**8.74**	32,716,590	**2,860**
Abundant Supply	Base	2015	1,746	332	0	92	11	**2,182**	**7.80**	-5	86	0	46	0	**8.27**	27,986,799	**2,314**
High Gas	Base	2015	2,363	324	0	24	11	**2,723**	**9.96**	-5	86	0	53	0	**10.47**	27,333,568	**2,862**
Low Gas	Base	2015	1,758	351	0	138	13	**2,261**	**6.98**	-5	86	0	43	0	**7.38**	32,382,589	**2,390**
Base Case	Base	2017	2,113	136	0	113	12	**2,375**	**7.68**	-3	89	23	77	0	**8.29**	30,914,203	**2,564**
Tight Supply	Base	2017	2,493	121	62	205	13	**2,894**	**8.58**	-2	89	23	55	0	**9.07**	33,743,698	**3,061**
Abundant Supply	Base	2017	1,807	112	0	119	11	**2,050**	**7.29**	-2	89	23	74	0	**7.96**	28,099,330	**2,236**
High Gas	Base	2017	2,476	97	0	31	11	**2,615**	**9.40**	-2	89	23	90	0	**10.13**	27,824,189	**2,817**
Low Gas	Base	2017	1,880	325	41	220	13	**2,480**	**7.52**	-7	85	23	55	0	**8.01**	32,995,974	**2,643**
Base Case	Base	2022	2,423	793	130	168	11	**3,526**	**10.96**	-28	64	81	67	0	**11.62**	32,166,853	**3,737**
Tight Supply	Base	2022	2,668	809	240	90	13	**3,819**	**10.73**	-28	64	81	67	0	**11.32**	35,607,162	**4,031**
Abundant Supply	Base	2022	2,018	611	38	228	10	**2,906**	**10.12**	-23	70	81	67	0	**10.87**	28,725,104	**3,123**
High Gas	Base	2022	2,819	526	37	231	10	**3,624**	**12.53**	-20	72	81	67	0	**13.29**	28,918,559	**3,843**
Low Gas	Base	2022	2,057	602	192	126	12	**2,990**	**8.70**	-21	71	81	67	0	**9.34**	34,358,715	**3,209**
Base Case	Expanded EE	2015	1,881	340	0	84	12	**2,317**	**8.04**	-21	177	0	47	0	**8.81**	28,833,089	**2,541**
Base Case	Expanded EE	2017	1,912	113	0	108	11	**2,144**	**7.50**	-10	188	23	76	0	**8.50**	28,610,924	**2,431**
Tight Supply	Expanded EE	2017	2,257	66	44	205	12	**2,585**	**8.22**	-6	192	23	55	0	**9.08**	31,440,418	**2,855**
Abundant Supply	Expanded EE	2017	1,634	100	0	111	10	**1,856**	**7.19**	-9	188	23	73	0	**8.30**	25,796,051	**2,141**
High Gas	Expanded EE	2017	2,249	97	0	31	10	**2,387**	**9.35**	-9	189	23	89	0	**10.54**	25,520,910	**2,689**
Low Gas	Expanded EE	2017	1,702	233	0	167	12	**2,115**	**6.89**	-21	177	23	67	0	**7.76**	30,692,695	**2,383**
Base Case	Expanded EE	2022	2,007	529	90	168	10	**2,804**	**10.08**	-84	114	81	67	0	**11.01**	27,827,752	**3,065**
Tight Supply	Expanded EE	2022	2,359	766	199	90	11	**3,426**	**10.96**	-118	80	81	67	0	**11.68**	31,268,062	**3,653**
Abundant Supply	Expanded EE	2022	1,655	292	0	114	9	**2,071**	**8.49**	-48	150	81	87	0	**9.79**	24,386,004	**2,388**
High Gas	Expanded EE	2022	2,330	314	0	7	9	**2,660**	**10.82**	-53	145	81	107	0	**12.18**	24,579,459	**2,993**
Low Gas	Expanded EE	2022	1,771	632	152	126	11	**2,693**	**8.97**	-98	100	81	67	0	**9.79**	30,019,615	**2,940**
Base Case	Exp. EE & Class I Flex.	2017	1,912	113	0	84	50	**2,159**	**7.55**	-10	158	23	76	0	**8.44**	28,610,924	**2,416**
Tight Supply	Exp. EE & Class I Flex.	2017	2,257	66	0	80	51	**2,455**	**7.81**	-6	162	23	79	0	**8.65**	31,440,418	**2,719**
Abundant Supply	Exp. EE & Class I Flex.	2017	1,634	100	0	86	49	**1,870**	**7.25**	-9	159	23	73	0	**8.24**	25,796,051	**2,125**
High Gas	Exp. EE & Class I Flex.	2017	2,249	97	0	24	49	**2,420**	**9.48**	-9	159	23	89	0	**10.54**	25,520,910	**2,691**
Low Gas	Exp. EE & Class I Flex.	2017	1,702	233	0	129	51	**2,116**	**6.90**	-21	147	23	67	0	**7.67**	30,692,695	**2,355**
Base Case	Exp. EE & Class I Flex.	2022	2,007	529	0	76	69	**2,681**	**9.64**	-84	59	81	91	0	**10.47**	27,827,752	**2,913**
Tight Supply	Exp. EE & Class I Flex.	2022	2,359	766	127	90	70	**3,412**	**10.91**	-118	26	81	67	0	**11.47**	31,268,062	**3,585**
Abundant Supply	Exp. EE & Class I Flex.	2022	1,655	292	0	85	68	**2,101**	**8.62**	-48	95	81	87	0	**9.69**	24,386,004	**2,364**
High Gas	Exp. EE & Class I Flex.	2022	2,330	314	0	5	68	**2,717**	**11.06**	-53	91	81	107	0	**12.19**	24,579,459	**2,995**
Low Gas	Exp. EE & Class I Flex.	2022	1,771	632	83	126	70	**2,682**	**8.93**	-98	45	81	67	0	**9.58**	30,019,615	**2,875**
Base Case	Full RPS Class I	2022	2,392	723	0	115	11	**3,242**	**10.08**	-26	66	179	92	0	**11.12**	32,177,167	**3,579**
Tight Supply	Full RPS Class I	2022	2,659	818	0	140	13	**3,630**	**10.20**	-28	64	261	90	0	**11.36**	35,608,558	**4,046**
Abundant Supply	Full RPS Class I	2022	2,013	564	0	121	10	**2,709**	**9.43**	-21	71	110	89	0	**10.36**	28,736,603	**2,979**
High Gas	Full RPS Class I	2022	2,807	466	0	0	10	**3,284**	**11.36**	-18	75	108	108	0	**12.36**	28,918,782	**3,575**
Low Gas	Full RPS Class I	2022	2,014	661	0	232	12	**2,919**	**8.50**	-23	69	226	78	0	**9.58**	34,359,009	**3,292**
Base Case	Low RPS Class I	2022	2,468	723	257	57	11	**3,517**	**10.93**	-26	66	0	51	0	**11.29**	32,183,993	**3,635**
Tight Supply	Low RPS Class I	2022	2,689	774	288	57	13	**3,822**	**10.73**	-27	66	0	51	0	**11.06**	35,612,354	**3,938**
Abundant Supply	Low RPS Class I	2022	2,042	520	217	50	10	**2,839**	**9.88**	-19	73	0	67	0	**10.36**	28,740,456	**2,979**
High Gas	Low RPS Class I	2022	2,854	351	215	53	10	**3,484**	**12.04**	-13	79	0	67	0	**12.55**	28,921,544	**3,629**
Low Gas	Low RPS Class I	2022	2,101	548	277	57	12	**2,996**	**8.72**	-19	73	0	51	0	**9.08**	34,364,519	**3,120**
Base Case	New COS Gen, Hi MOP	2017	2,064	128	0	117	12	**2,322**	**7.50**	-3	89	23	76	63	**8.31**	30,968,382	**2,573**
Tight Supply	New COS Gen, Hi MOP	2017	2,404	121	62	205	13	**2,805**	**8.30**	-2	89	23	55	46	**8.93**	33,789,321	**3,019**
Abundant Supply	New COS Gen, Hi MOP	2017	1,773	112	0	122	11	**2,018**	**7.17**	-2	89	23	73	77	**8.10**	28,154,369	**2,281**
High Gas	New COS Gen, Hi MOP	2017	2,450	97	0	34	11	**2,592**	**9.30**	-2	89	23	89	80	**10.31**	27,864,174	**2,874**
Low Gas	New COS Gen, Hi MOP	2017	1,785	320	41	220	13	**2,379**	**7.20**	-7	85	23	55	45	**7.83**	33,040,299	**2,587**
Base Case	New COS Gen, Hi MOP	2022	2,357	797	130	168	11	**3,464**	**10.75**	-28	64	81	67	35	**11.51**	32,222,776	**3,710**
Tight Supply	New COS Gen, Hi MOP	2022	2,649	849	240	90	13	**3,840**	**10.77**	-29	63	81	67	-27	**11.28**	35,656,590	**4,023**
Abundant Supply	New COS Gen, Hi MOP	2022	1,975	611	38	228	10	**2,863**	**9.95**	-23	70	81	67	53	**10.88**	28,782,089	**3,133**
High Gas	New COS Gen, Hi MOP	2022	2,773	526	37	231	10	**3,578**	**12.36**	-20	72	81	67	55	**13.31**	28,959,004	**3,853**
Low Gas	New COS Gen, Hi MOP	2022	2,046	629	192	126	12	**3,006**	**8.74**	-22	70	81	67	-28	**9.29**	34,403,541	**3,196**
Base Case	New COS Gen, Lo MOP	2017	2,064	101	0	118	12	**2,295**	**7.41**	-2	89	23	76	56	**8.20**	30,968,382	**2,540**
Tight Supply	New COS Gen, Lo MOP	2017	2,404	67	62	205	13	**2,752**	**8.14**	-1	90	23	55	41	**8.76**	33,789,300	**2,961**
Abundant Supply	New COS Gen, Lo MOP	2017	1,773	91	0	123	11	**1,998**	**7.10**	-2	89	23	73	70	**8.01**	28,154,369	**2,254**
High Gas	New COS Gen, Lo MOP	2017	2,450	70	0	35	11	**2,566**	**9.21**	-2	90	23	89	75	**10.20**	27,864,174	**2,843**
Low Gas	New COS Gen, Lo MOP	2017	1,785	146	41	220	13	**2,205**	**6.67**	-3	88	23	55	34	**7.28**	33,040,299	**2,406**
Base Case	New COS Gen, Lo MOP	2022	2,362	745	130	168	11	**3,417**	**10.60**	-27	66	81	67	-17	**11.21**	32,222,599	**3,612**
Tight Supply	New COS Gen, Lo MOP	2022	2,649	849	240	90	13	**3,840**	**10.77**	-29	63	81	67	-27	**11.28**	35,656,590	**4,023**
Abundant Supply	New COS Gen, Lo MOP	2022	1,978	520	38	228	10	**2,774**	**9.64**	-19	73	81	67	15	**10.46**	28,782,193	**3,010**
High Gas	New COS Gen, Lo MOP	2022	2,776	390	37	231	10	**3,445**	**11.90**	-15	78	81	67	27	**12.76**	28,959,094	**3,697**
Low Gas	New COS Gen, Lo MOP	2022	2,046	630	192	126	12	**3,006**	**8.74**	-22	70	81	67	-28	**9.29**	34,403,541	**3,196**

Figure 4
Connecticut Power Supply-Related Costs, Differences Relative to Base Case

Future	Resource Scenario	Year	Energy Cost ($Mil)	Capacity Cost ($Mil)	Class I ACP Cost ($Mil)	Class I REC Cost ($Mil)	Class III ($Mil)	**TOTAL GENERATION SVC COST** ($Mil)	**AVERAGE GENERATION SVC COST** (¢/kWh)	EE FCM Credit ($Mil)	C&LM Charges for Efficiency Programs ($Mil)	Tx Cost for RPS ($Mil)	Renew. Prog. Net of Mrkt. Revs. ($Mil)	Net Cost of New COS Generation ($Mil)	**AVG COST** (¢/kWh)	**Retail Load** (MWh)	**TOTAL COST** ($Mil)
(DIFFERENCES IN OTHER RESOURCE SCENARIOS COMPARED TO BASE SCENARIO)																	
Base Case	Expanded EE	2015	(118)	(0)	0	(3)	(1)	**(122)**	**(0.00)**	(16)	91	0	(0)	0	**0.34**	(1,514,517)	**(31)**
Base Case	Expanded EE	2017	(202)	(24)	0	(4)	(1)	**(231)**	**(0.19)**	(7)	99	0	(1)	0	**0.21**	(2,303,279)	**(132)**
Tight Supply	Expanded EE	2017	(235)	(54)	(18)	0	(1)	**(309)**	**(0.35)**	(3)	103	0	0	0	**0.01**	(2,303,279)	**(206)**
Abundant Supply	Expanded EE	2017	(173)	(12)	0	(8)	(1)	**(194)**	**(0.10)**	(7)	100	0	(0)	0	**0.34**	(2,303,279)	**(95)**
High Gas	Expanded EE	2017	(226)	(0)	0	(0)	(1)	**(227)**	**(0.04)**	(7)	99	0	(0)	0	**0.41**	(2,303,279)	**(129)**
Low Gas	Expanded EE	2017	(178)	(92)	(41)	(53)	(1)	**(365)**	**(0.62)**	(14)	92	0	13	0	**(0.24)**	(2,303,279)	**(260)**
Base Case	Expanded EE	2022	(416)	(264)	(40)	0	(2)	**(722)**	**(0.89)**	(56)	50	0	0	0	**(0.60)**	(4,339,100)	**(672)**
Tight Supply	Expanded EE	2022	(309)	(43)	(40)	0	(2)	**(393)**	**0.23**	(90)	16	0	0	0	**0.36**	(4,339,100)	**(378)**
Abundant Supply	Expanded EE	2022	(362)	(319)	(38)	(114)	(2)	**(836)**	**(1.63)**	(26)	80	0	20	0	**(1.08)**	(4,339,100)	**(735)**
High Gas	Expanded EE	2022	(488)	(212)	(37)	(225)	(2)	**(963)**	**(1.71)**	(33)	73	0	40	0	**(1.11)**	(4,339,100)	**(851)**
Low Gas	Expanded EE	2022	(286)	30	(40)	0	(2)	**(297)**	**0.27**	(77)	29	0	0	0	**0.45**	(4,339,100)	**(269)**
Base Case	Exp. EE & Class I Flex.	2017	(202)	(24)	0	(29)	38	**(216)**	**(0.14)**	(7)	69	0	(1)	0	**0.15**	(2,303,279)	**(147)**
Tight Supply	Exp. EE & Class I Flex.	2017	(235)	(54)	(62)	(125)	38	**(439)**	**(0.77)**	(3)	73	0	24	0	**(0.42)**	(2,303,279)	**(342)**
Abundant Supply	Exp. EE & Class I Flex.	2017	(173)	(12)	0	(33)	38	**(180)**	**(0.05)**	(7)	70	0	(0)	0	**0.28**	(2,303,279)	**(111)**
High Gas	Exp. EE & Class I Flex.	2017	(226)	(0)	0	(7)	38	**(195)**	**0.08**	(7)	70	0	(0)	0	**0.42**	(2,303,279)	**(126)**
Low Gas	Exp. EE & Class I Flex.	2017	(178)	(92)	(41)	(91)	38	**(364)**	**(0.62)**	(14)	63	0	13	0	**(0.34)**	(2,303,279)	**(288)**
Base Case	Exp. EE & Class I Flex.	2022	(416)	(264)	(130)	(92)	57	**(844)**	**(1.33)**	(56)	(5)	0	25	0	**(1.15)**	(4,339,100)	**(824)**
Tight Supply	Exp. EE & Class I Flex.	2022	(309)	(43)	(113)	0	57	**(407)**	**0.19**	(90)	(39)	0	0	0	**0.15**	(4,339,100)	**(446)**
Abundant Supply	Exp. EE & Class I Flex.	2022	(362)	(319)	(38)	(143)	57	**(805)**	**(1.50)**	(26)	25	0	20	0	**(1.18)**	(4,339,100)	**(759)**
High Gas	Exp. EE & Class I Flex.	2022	(488)	(212)	(37)	(226)	57	**(906)**	**(1.47)**	(33)	18	0	40	0	**(1.10)**	(4,339,100)	**(848)**
Low Gas	Exp. EE & Class I Flex.	2022	(286)	30	(110)	0	57	**(308)**	**0.23**	(77)	(26)	0	0	0	**0.24**	(4,339,100)	**(334)**
Base Case	Full RPS Class I	2022	(31)	(70)	(130)	(53)	0	**(284)**	**(0.89)**	2	2	98	25	0	**(0.49)**	10,314	**(158)**
Tight Supply	Full RPS Class I	2022	(8)	10	(240)	50	0	**(189)**	**(0.53)**	(0)	(0)	181	24	0	**0.04**	1,395	**16**
Abundant Supply	Full RPS Class I	2022	(5)	(48)	(38)	(106)	0	**(198)**	**(0.69)**	2	2	29	22	0	**(0.51)**	11,498	**(144)**
High Gas	Full RPS Class I	2022	(11)	(61)	(37)	(231)	0	**(340)**	**(1.18)**	2	2	28	41	0	**(0.93)**	223	**(269)**
Low Gas	Full RPS Class I	2022	(44)	59	(192)	106	0	**(71)**	**(0.21)**	(2)	(2)	145	11	0	**0.24**	294	**83**
Base Case	Low RPS Class I	2022	46	(70)	127	(111)	0	**(8)**	**(0.03)**	2	2	(81)	(16)	0	**(0.32)**	17,140	**(103)**
Tight Supply	Low RPS Class I	2022	22	(34)	49	(33)	0	**3**	**0.01**	1	1	(81)	(16)	0	**(0.26)**	5,192	**(92)**
Abundant Supply	Low RPS Class I	2022	25	(92)	178	(178)	0	**(67)**	**(0.24)**	3	3	(81)	0	0	**(0.51)**	15,351	**(144)**
High Gas	Low RPS Class I	2022	35	(175)	178	(178)	0	**(140)**	**(0.49)**	7	7	(81)	0	0	**(0.74)**	2,985	**(214)**
Low Gas	Low RPS Class I	2022	44	(54)	85	(69)	0	**6**	**0.02**	2	2	(81)	(16)	0	**(0.26)**	5,804	**(89)**
Base Case	New COS Gen, Hi MOP	2017	(49)	(8)	0	5	0	**(53)**	**(0.19)**	0	0	0	(1)	63	**0.02**	54,180	**9**
Tight Supply	New COS Gen, Hi MOP	2017	(89)	0	0	0	0	**(89)**	**(0.27)**	(0)	(0)	0	0	46	**(0.14)**	45,624	**(42)**
Abundant Supply	New COS Gen, Hi MOP	2017	(34)	0	0	3	0	**(31)**	**(0.13)**	0	0	0	(1)	77	**0.15**	55,039	**45**
High Gas	New COS Gen, Hi MOP	2017	(26)	0	0	3	0	**(23)**	**(0.10)**	0	0	0	(1)	80	**0.19**	39,985	**57**
Low Gas	New COS Gen, Hi MOP	2017	(96)	(5)	0	0	0	**(100)**	**(0.31)**	0	0	0	0	45	**(0.18)**	44,325	**(56)**
Base Case	New COS Gen, Hi MOP	2022	(66)	4	0	0	0	**(62)**	**(0.21)**	(0)	(0)	0	0	35	**(0.11)**	55,923	**(28)**
Tight Supply	New COS Gen, Hi MOP	2022	(19)	40	0	0	0	**21**	**0.04**	(1)	(1)	0	0	(27)	**(0.04)**	49,428	**(8)**
Abundant Supply	New COS Gen, Hi MOP	2022	(43)	0	0	0	0	**(43)**	**(0.17)**	0	0	0	0	53	**0.01**	56,985	**10**
High Gas	New COS Gen, Hi MOP	2022	(46)	0	0	0	0	**(46)**	**(0.17)**	0	0	0	0	55	**0.02**	40,445	**10**
Low Gas	New COS Gen, Hi MOP	2022	(11)	27	0	0	0	**16**	**0.03**	(1)	(1)	0	0	(28)	**(0.05)**	44,826	**(13)**
Base Case	New COS Gen, Lo MOP	2017	(49)	(36)	0	5	0	**(80)**	**(0.27)**	1	1	0	(1)	56	**(0.09)**	54,180	**(24)**
Tight Supply	New COS Gen, Lo MOP	2017	(89)	(53)	0	0	0	**(142)**	**(0.43)**	1	1	0	0	41	**(0.31)**	45,602	**(100)**
Abundant Supply	New COS Gen, Lo MOP	2017	(34)	(21)	0	4	0	**(51)**	**(0.20)**	0	0	0	(1)	70	**0.05**	55,039	**19**
High Gas	New COS Gen, Lo MOP	2017	(26)	(27)	0	4	0	**(49)**	**(0.19)**	1	1	0	(1)	75	**0.08**	39,985	**26**
Low Gas	New COS Gen, Lo MOP	2017	(96)	(179)	0	0	0	**(275)**	**(0.84)**	4	4	0	0	34	**(0.73)**	44,325	**(237)**
Base Case	New COS Gen, Lo MOP	2022	(61)	(48)	0	0	0	**(109)**	**(0.36)**	2	2	0	0	(17)	**(0.41)**	55,746	**(125)**
Tight Supply	New COS Gen, Lo MOP	2022	(19)	40	0	0	0	**21**	**0.04**	(1)	(1)	0	0	(27)	**(0.04)**	49,428	**(8)**
Abundant Supply	New COS Gen, Lo MOP	2022	(40)	(92)	0	0	0	**(132)**	**(0.48)**	3	3	0	0	15	**(0.42)**	57,089	**(113)**
High Gas	New COS Gen, Lo MOP	2022	(42)	(136)	0	0	0	**(178)**	**(0.63)**	5	5	0	0	27	**(0.52)**	40,535	**(147)**
Low Gas	New COS Gen, Lo MOP	2022	(11)	28	0	0	0	**16**	**0.04**	(1)	(1)	0	0	(28)	**(0.05)**	44,826	**(13)**

Figure 5
Electric Sector Emissions

Future	Resource Scenario	Year	**ISO-Wide** CO2 Emissions *(Tons)*	**ISO-Wide** SOx Emissions *(Tons)*	**ISO-Wide** NOx Emissions *(Tons)*	**Connecticut** CO2 Emissions *(Tons)*	**Connecticut** SOx Emissions *(Tons)*	**Connecticut** NOx Emissions *(Tons)*	**Connecticut** Ozone Season NOx Emissions *(Tons)*	**Connecticut** HEDD (10-Day) NOx Emissions *(Tons/Day)*
Base Case	Base	2015	36,318,798	12,401	12,901	7,763,306	1,113	1,815	767	15
Tight Supply	Base	2015	41,494,473	14,728	14,949	8,661,246	1,335	2,062	896	17
Abundant Supply	Base	2015	29,069,515	8,792	10,442	6,363,727	655	1,407	590	9
High Gas	Base	2015	33,005,898	17,987	16,009	8,108,171	2,808	2,817	1,334	12
Low Gas	Base	2015	38,516,412	8,669	11,243	8,350,082	482	1,528	819	18
Base Case	Base	2017	37,465,514	13,276	14,187	7,950,743	1,347	2,019	861	16
Tight Supply	Base	2017	44,067,378	16,986	16,968	9,230,197	1,808	2,438	1,119	20
Abundant Supply	Base	2017	28,875,774	8,386	10,917	5,773,611	275	1,129	530	8
High Gas	Base	2017	33,268,000	17,456	16,248	8,212,913	2,949	2,973	1,404	12
Low Gas	Base	2017	39,409,282	10,316	12,335	8,369,751	487	1,591	857	18
Base Case	Base	2022	40,249,892	16,211	16,509	8,535,874	1,831	2,373	1,134	21
Tight Supply	Base	2022	47,517,745	17,099	18,009	8,814,360	1,908	2,454	1,173	21
Abundant Supply	Base	2022	30,268,778	10,055	12,671	5,805,455	357	1,198	613	13
High Gas	Base	2022	34,423,989	17,988	16,760	8,469,110	3,023	3,027	1,435	17
Low Gas	Base	2022	41,074,606	9,931	12,836	8,306,472	663	1,691	964	22
Base Case	Expanded EE	2015	35,473,238	11,945	12,480	7,670,833	1,027	1,685	677	12
Base Case	Expanded EE	2017	36,238,433	12,781	13,714	7,721,260	1,255	1,911	771	13
Tight Supply	Expanded EE	2017	42,701,669	15,892	16,249	9,011,352	1,649	2,320	1,031	18
Abundant Supply	Expanded EE	2017	27,793,955	8,217	10,643	5,672,540	267	1,100	505	6
High Gas	Expanded EE	2017	32,182,831	17,252	16,028	7,997,137	2,933	2,934	1,377	11
Low Gas	Expanded EE	2017	37,990,248	9,177	11,517	8,051,810	295	1,433	726	13
Base Case	Expanded EE	2022	37,925,883	15,033	15,543	8,101,462	1,597	2,155	956	17
Tight Supply	Expanded EE	2022	45,826,265	17,799	17,979	9,217,346	2,031	2,562	1,224	21
Abundant Supply	Expanded EE	2022	28,239,769	9,614	12,150	5,448,331	271	1,091	527	8
High Gas	Expanded EE	2022	32,467,617	17,597	16,370	8,092,710	2,904	2,925	1,354	12
Low Gas	Expanded EE	2022	38,867,394	9,278	12,164	8,049,646	360	1,483	798	16
Base Case	Exp. EE & Class I Flex.	2017	36,238,433	12,781	13,714	7,721,260	1,255	1,911	771	13
Tight Supply	Exp. EE & Class I Flex.	2017	42,701,669	15,892	16,249	9,011,352	1,649	2,320	1,031	18
Abundant Supply	Exp. EE & Class I Flex.	2017	27,793,955	8,217	10,643	5,672,540	267	1,100	505	6
High Gas	Exp. EE & Class I Flex.	2017	32,182,831	17,252	16,028	7,997,137	2,933	2,934	1,377	11
Low Gas	Exp. EE & Class I Flex.	2017	37,990,248	9,177	11,517	8,051,810	295	1,433	726	13
Base Case	Exp. EE & Class I Flex.	2022	37,925,883	15,033	15,543	8,101,462	1,597	2,155	956	17
Tight Supply	Exp. EE & Class I Flex.	2022	45,826,265	17,799	17,979	9,217,346	2,031	2,562	1,224	21
Abundant Supply	Exp. EE & Class I Flex.	2022	28,239,769	9,614	12,150	5,448,331	271	1,091	527	8
High Gas	Exp. EE & Class I Flex.	2022	32,467,617	17,597	16,370	8,092,710	2,904	2,925	1,354	12
Low Gas	Exp. EE & Class I Flex.	2022	38,867,394	9,278	12,164	8,049,646	360	1,483	798	16
Base Case	Full RPS Class I	2022	38,823,505	15,661	16,027	8,243,812	1,666	2,243	1,059	21
Tight Supply	Full RPS Class I	2022	45,247,476	16,936	17,594	8,740,684	1,909	2,451	1,172	20
Abundant Supply	Full RPS Class I	2022	29,958,625	10,031	12,684	5,800,957	358	1,196	614	13
High Gas	Full RPS Class I	2022	34,081,538	17,965	16,701	8,402,194	3,014	3,010	1,424	16
Low Gas	Full RPS Class I	2022	39,015,272	8,905	12,097	8,072,205	609	1,628	917	21
Base Case	Low RPS Class I	2022	42,362,632	17,691	17,344	8,967,398	1,939	2,486	1,177	22
Tight Supply	Low RPS Class I	2022	49,444,871	17,536	18,461	9,044,095	2,011	2,529	1,180	21
Abundant Supply	Low RPS Class I	2022	32,236,874	10,710	13,297	6,153,040	355	1,227	625	13
High Gas	Low RPS Class I	2022	36,235,765	18,391	17,126	8,881,319	3,080	3,087	1,456	17
Low Gas	Low RPS Class I	2022	43,155,062	10,741	13,580	8,555,519	719	1,747	979	23
Base Case	New COS Gen, Hi MOP	2017	37,070,708	12,388	13,649	9,365,794	1,178	2,159	876	14
Tight Supply	New COS Gen, Hi MOP	2017	43,546,429	15,308	16,133	10,785,458	1,606	2,597	1,160	19
Abundant Supply	New COS Gen, Hi MOP	2017	28,701,395	7,979	10,687	7,282,780	281	1,392	639	7
High Gas	New COS Gen, Hi MOP	2017	33,230,714	17,219	16,250	9,608,063	2,949	3,228	1,516	12
Low Gas	New COS Gen, Hi MOP	2017	38,918,512	8,548	11,374	10,019,502	429	1,839	943	18
Base Case	New COS Gen, Hi MOP	2022	39,848,461	15,230	15,931	9,950,616	1,645	2,508	1,162	21
Tight Supply	New COS Gen, Hi MOP	2022	47,272,057	16,749	17,722	10,538,495	1,852	2,697	1,251	22
Abundant Supply	New COS Gen, Hi MOP	2022	30,224,192	9,797	12,565	7,267,982	337	1,418	688	11
High Gas	New COS Gen, Hi MOP	2022	34,420,962	17,826	16,790	9,839,580	3,002	3,270	1,533	16
Low Gas	New COS Gen, Hi MOP	2022	40,921,131	9,493	12,610	10,301,850	641	2,001	1,076	24
Base Case	New COS Gen, Lo MOP	2017	37,070,708	12,388	13,649	9,365,794	1,178	2,159	876	14
Tight Supply	New COS Gen, Lo MOP	2017	43,543,871	15,304	16,130	10,783,532	1,602	2,594	1,158	19
Abundant Supply	New COS Gen, Lo MOP	2017	28,701,395	7,979	10,687	7,282,780	281	1,392	639	7
High Gas	New COS Gen, Lo MOP	2017	33,230,714	17,219	16,250	9,608,063	2,949	3,228	1,516	12
Low Gas	New COS Gen, Lo MOP	2017	38,918,512	8,548	11,374	10,019,502	429	1,839	943	18
Base Case	New COS Gen, Lo MOP	2022	39,839,987	15,189	15,935	9,954,941	1,655	2,514	1,168	22
Tight Supply	New COS Gen, Lo MOP	2022	47,272,057	16,749	17,722	10,538,495	1,852	2,697	1,251	22
Abundant Supply	New COS Gen, Lo MOP	2022	30,222,994	9,785	12,566	7,264,671	308	1,417	687	11
High Gas	New COS Gen, Lo MOP	2022	34,417,593	17,791	16,789	9,835,783	2,966	3,265	1,528	16
Low Gas	New COS Gen, Lo MOP	2022	40,921,131	9,493	12,610	10,301,850	641	2,001	1,076	24

Figure 6
Electric Sector Emissions, Differences Relative to Base Case

Future	Resource Scenario	Year	**ISO-Wide** CO2 Emissions *(Tons)* *[1]*	**ISO-Wide** SOx Emissions *(Tons)* *[2]*	**ISO-Wide** NOx Emissions *(Tons)* *[3]*	**Connecticut** CO2 Emissions *(Tons)* *[4]*	**Connecticut** SOx Emissions *(Tons)* *[5]*	**Connecticut** NOx Emissions *(Tons)* *[6]*	**Connecticut** Ozone Season NOx Emissions *(Tons)* *[7]*	**Connecticut** HEDD (10-Day) NOx Emissions *(Tons/Day)* *[8]*
(DIFFERENCES IN OTHER RESOURCE SCENARIOS COMPARED TO BASE SCENARIO)										
Base Case	Expanded EE	2015	(845,560)	(456)	(421)	(92,473)	(87)	(130)	(90)	(2)
Base Case	Expanded EE	2017	(1,227,081)	(495)	(473)	(229,483)	(92)	(108)	(91)	(3)
Tight Supply	Expanded EE	2017	(1,365,709)	(1,094)	(720)	(218,846)	(160)	(117)	(88)	(2)
Abundant Supply	Expanded EE	2017	(1,081,819)	(169)	(274)	(101,072)	(8)	(29)	(26)	(2)
High Gas	Expanded EE	2017	(1,085,169)	(204)	(221)	(215,776)	(16)	(40)	(26)	(1)
Low Gas	Expanded EE	2017	(1,419,033)	(1,139)	(818)	(317,941)	(192)	(157)	(131)	(6)
Base Case	Expanded EE	2022	(2,324,009)	(1,178)	(966)	(434,412)	(234)	(218)	(178)	(5)
Tight Supply	Expanded EE	2022	(1,691,481)	700	(29)	402,986	123	108	52	(0)
Abundant Supply	Expanded EE	2022	(2,029,009)	(441)	(521)	(357,124)	(86)	(107)	(86)	(5)
High Gas	Expanded EE	2022	(1,956,372)	(392)	(389)	(376,400)	(119)	(102)	(81)	(5)
Low Gas	Expanded EE	2022	(2,207,212)	(652)	(672)	(256,826)	(302)	(208)	(166)	(6)
Base Case	Exp. EE & Class I Flex.	2017	(1,227,081)	(495)	(473)	(229,483)	(92)	(108)	(91)	(3)
Tight Supply	Exp. EE & Class I Flex.	2017	(1,365,709)	(1,094)	(720)	(218,846)	(160)	(117)	(88)	(2)
Abundant Supply	Exp. EE & Class I Flex.	2017	(1,081,819)	(169)	(274)	(101,072)	(8)	(29)	(26)	(2)
High Gas	Exp. EE & Class I Flex.	2017	(1,085,169)	(204)	(221)	(215,776)	(16)	(40)	(26)	(1)
Low Gas	Exp. EE & Class I Flex.	2017	(1,419,033)	(1,139)	(818)	(317,941)	(192)	(157)	(131)	(6)
Base Case	Exp. EE & Class I Flex.	2022	(2,324,009)	(1,178)	(966)	(434,412)	(234)	(218)	(178)	(5)
Tight Supply	Exp. EE & Class I Flex.	2022	(1,691,481)	700	(29)	402,986	123	108	52	(0)
Abundant Supply	Exp. EE & Class I Flex.	2022	(2,029,009)	(441)	(521)	(357,124)	(86)	(107)	(86)	(5)
High Gas	Exp. EE & Class I Flex.	2022	(1,956,372)	(392)	(389)	(376,400)	(119)	(102)	(81)	(5)
Low Gas	Exp. EE & Class I Flex.	2022	(2,207,212)	(652)	(672)	(256,826)	(302)	(208)	(166)	(6)
Base Case	Full RPS Class I	2022	(1,426,386)	(550)	(482)	(292,062)	(165)	(130)	(74)	(0)
Tight Supply	Full RPS Class I	2022	(2,270,269)	(163)	(415)	(73,676)	1	(3)	(1)	(1)
Abundant Supply	Full RPS Class I	2022	(310,154)	(24)	13	(4,498)	1	(2)	1	0
High Gas	Full RPS Class I	2022	(342,452)	(23)	(58)	(66,916)	(9)	(17)	(11)	(1)
Low Gas	Full RPS Class I	2022	(2,059,334)	(1,026)	(739)	(234,268)	(53)	(63)	(47)	(1)
Base Case	Low RPS Class I	2022	2,112,740	1,480	835	431,524	109	113	43	0
Tight Supply	Low RPS Class I	2022	1,927,125	436	453	229,735	104	75	8	(0)
Abundant Supply	Low RPS Class I	2022	1,968,096	655	626	347,586	(2)	30	12	0
High Gas	Low RPS Class I	2022	1,811,775	403	366	412,209	57	60	21	(0)
Low Gas	Low RPS Class I	2022	2,080,456	811	745	249,047	57	56	15	1
Base Case	New COS Gen, Hi MOP	2017	(394,806)	(888)	(538)	1,415,051	(169)	141	15	(2)
Tight Supply	New COS Gen, Hi MOP	2017	(520,950)	(1,678)	(835)	1,555,260	(203)	159	42	(1)
Abundant Supply	New COS Gen, Hi MOP	2017	(174,379)	(406)	(230)	1,509,169	6	264	109	(1)
High Gas	New COS Gen, Hi MOP	2017	(37,286)	(237)	2	1,395,150	0	254	112	(0)
Low Gas	New COS Gen, Hi MOP	2017	(490,770)	(1,768)	(960)	1,649,751	(57)	248	86	(1)
Base Case	New COS Gen, Hi MOP	2022	(401,431)	(981)	(578)	1,414,741	(186)	135	29	(1)
Tight Supply	New COS Gen, Hi MOP	2022	(245,688)	(350)	(286)	1,724,135	(56)	243	79	1
Abundant Supply	New COS Gen, Hi MOP	2022	(44,586)	(258)	(106)	1,462,527	(20)	220	75	(2)
High Gas	New COS Gen, Hi MOP	2022	(3,027)	(162)	31	1,370,470	(21)	243	97	(1)
Low Gas	New COS Gen, Hi MOP	2022	(153,475)	(438)	(226)	1,995,377	(21)	310	112	1
Base Case	New COS Gen, Lo MOP	2017	(394,806)	(888)	(538)	1,415,051	(169)	141	15	(2)
Tight Supply	New COS Gen, Lo MOP	2017	(523,507)	(1,682)	(838)	1,553,334	(207)	156	39	(1)
Abundant Supply	New COS Gen, Lo MOP	2017	(174,379)	(406)	(230)	1,509,169	6	264	109	(1)
High Gas	New COS Gen, Lo MOP	2017	(37,286)	(237)	2	1,395,150	0	254	112	(0)
Low Gas	New COS Gen, Lo MOP	2017	(490,770)	(1,768)	(960)	1,649,751	(57)	248	86	(1)
Base Case	New COS Gen, Lo MOP	2022	(409,905)	(1,022)	(574)	1,419,066	(175)	141	35	0
Tight Supply	New COS Gen, Lo MOP	2022	(245,688)	(350)	(286)	1,724,135	(56)	243	79	1
Abundant Supply	New COS Gen, Lo MOP	2022	(45,784)	(270)	(105)	1,459,216	(49)	220	74	(2)
High Gas	New COS Gen, Lo MOP	2022	(6,396)	(197)	29	1,366,673	(57)	238	93	(1)
Low Gas	New COS Gen, Lo MOP	2022	(153,475)	(438)	(226)	1,995,377	(21)	310	112	1

APPENDIX B

RESOURCE ADEQUACY

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INTRODUCTION

ISO New England (ISO-NE) defines four separate resource adequacy requirements affecting Connecticut: the ISO-NE-wide Installed Capacity Requirement (ICR); two Connecticut requirements under the Transmission Security Analysis (CT TSA) and the Connecticut Local Resource Adequacy (CT LRA) requirement, where the more stringent of the two governs; and the Connecticut requirement in the Locational Forward Reserve Market (LFRM).

This appendix describes the load forecasts that largely drive the first three requirements, then estimates the magnitude of each requirement over the next ten years. Next, the supply of resources is projected in the context of ISO-NE's forward capacity market. This is the most involved part of the analysis because, although there is rich publicly-available data on existing and planned resources, future entry and exit decisions depend primarily on private market participants' decisions that can only be estimated.

Finally, resource adequacy is assessed by comparing the projected supply to the requirements. This assessment is performed for a Base Case and for alternative Futures reflecting different market conditions.

THE LOAD FORECAST

ISO New England's Forecast

All reliability requirements in the ISO are driven by projections of peak demand. Connecticut and ISO-wide reliability requirements are based on ISO's 2011-2020 Forecast Report of Capacity, Energy, Loads, and Transmission (2011 CELT), particularly the load forecast reflecting normal weather ("50/50") and base economic growth conditions for the years 2011 through 2020.[1,2] To forecast peak loads over the entire study period through 2022, we extrapolated the ISO's forecast using the 2019-2020 load growth rates.

The ISO publishes several different forecasts to simulate the uncertainty surrounding 10-year forecasts for load. Our Base Case uses the ISO's weather-normalized 50/50 demand forecasts that reflect normal weather and base economic growth.[3] This is a "most likely" forecast because it implies that there is a 50% chance the actual load will exceed the forecast and a 50% chance the actual load will be lower than the forecast. We also test sensitivities using ISO forecasts that reflect more extreme weather, and forecasts that reflect both faster and slower economic growth. Figure 1 presents the ISO's 2011 50/50 gross peak load forecasts for the Connecticut sub-area and the ISO, respectively. The gross peak load does not reflect the impact of certain energy

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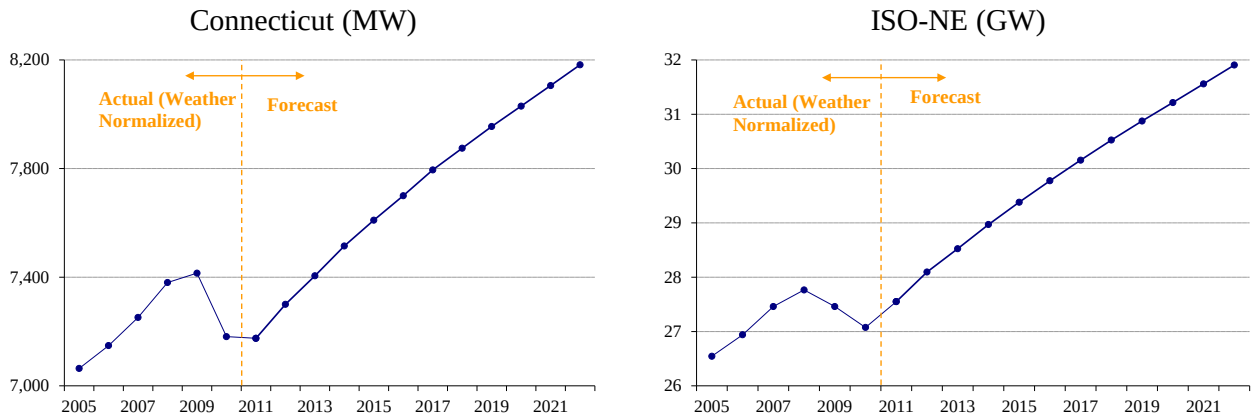
1 "2011-2020 Forecast Report of Capacity, Energy, Loads, and Transmission," ISO New England, May 2011. Available at http://www.iso-ne.com/trans/celt/index.html

2 All Connecticut peak load figures discussed in this section refer to the Connecticut sub-area (ISO zones Norwalk, SW Connecticut, and rest of Connecticut). This excludes a small amount (approximately one percent) of state demand physically in Connecticut but electrically in Western Massachusetts.

3 The ISO's forecast is a "busbar" forecast, meaning that it reflects the amount needed to be produced at generation sources to serve all load plus losses. These losses are estimated at roughly eight percent, a factor that the ISO uses to gross up metered (customer) load to account for transmission and distribution losses.

efficiency measures that were implemented or are planned for any year after 2006, because those are counted on the supply-side for meeting peak demand resource adequacy, as discussed in the next sub-section.

Figure 1
ISO-NE CELT Gross Peak Load Forecast[4]



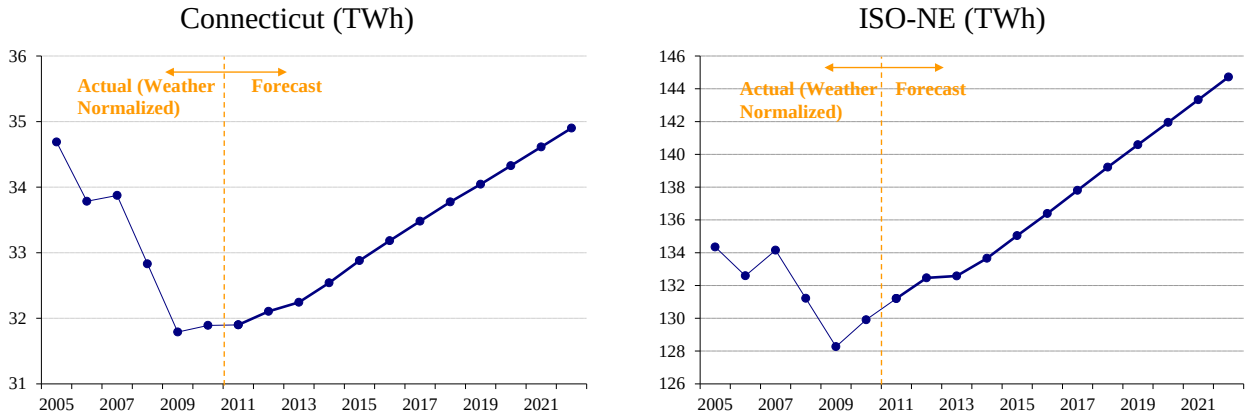
While the total amount of resources must be sufficient to meet demand reliably during peak hours, only the resources with the lowest variable costs are used to provide energy in the rest of the hours. The energy forecast is therefore a critical input to the DAYZER model that this IRP relied on to simulate the production of energy.

ISO-NE's 2011 CELT report projects a recovery in energy usage from 2009 levels, with a long-term energy growth of 0.9-1.0% per year. For the system as a whole, the ISO projects that energy needs will exceed pre-recession 2007 levels by 2015. Connecticut's recovery is projected to be slower, reaching pre-recession 2007 energy levels by 2019. Figure 2 presents the ISO's 2011 CELT 50/50 *net energy forecasts* for Connecticut and the ISO, respectively.[5] The net forecasts account for energy efficiency, as discussed in the next section.

4 CT 2010 peak value is a Brattle estimate based on ISO-NE data.

5 CT 2009 and 2010 energy values are Brattle estimates based on ISO-NE data.

Figure 2
ISO-NE Net Energy Forecast



ISO New England's CELT Forecasting Methodology and Energy Efficiency

ISO New England employs historical data from the 1991-2010 period to estimate a regression model that explains the relationship between the net energy for load (NEL) and various independent variables. The independent variables include electricity prices, economic variables (real personal income or real gross state product in each state), and weather conditions (cooling and heating degree days).[6] Once ISO-NE estimates the regression coefficients, it enters projected values for each independent variable into the regression equations to produce the model forecasts. ISO-NE's forecasts also adjust for the impact of Federal Electric Appliance Standards (effective 2013 forward) that would not be captured by the econometric models.[7]

The ISO New England's peak load model explains the historic daily peak load data in the 2001-2010 period using energy consumption, weather variables, and other dummy variables to account for weekends, holidays, and other relevant factors. A separate model is estimated for each New England State for each month. The peak model accounts for both weather-sensitive load and non-weather sensitive load. Similar to the NEL model, the resulting forecasts from the peak model are adjusted to include the impacts of Federal Electric Appliance Standards starting in 2013 and going forward.

It is important to understand how energy efficiency activities are incorporated in the ISO's load forecasting methodology. We present the following discussion for the NEL model, but it applies similarly to the peak demand model.

The NEL variable is *net* of energy efficiency in the period from 1991 to 2006. This implies that the impacts of the energy efficiency programs are already embedded in the data in the 1991-2006

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6 The ISO's forecast is a "busbar forecast," meaning that it reflects the amount needed to be produced at generation sources to serve all load plus losses. These losses are estimated at roughly eight percent, a factor that the ISO uses to gross up metered (customer) load to account for transmission and distribution losses.

7 CELT model structures available at: http://www.iso-ne.com/trans/celt/fsct_detail/2011/model_structures_2011.pdf.

period, and projections based on the observed growth rates imply continued energy efficiency improvements at their historic levels. ISO-NE treats the historic data for 2007 through 2010 differently. For that period, ISO grosses up the NEL for energy efficiency and other demand resources participating in the transition to FCM.[8] The load is reconstituted by adding the energy efficiency savings back to the metered load.[9] Thus, the NEL values used in the energy regression do not include the impacts of energy efficiency on historic electricity growth rates for 2006 through 2010, although they do for 1991 through 2006.

After the regression model is estimated and model parameters are obtained, the forecasts are generated for the 2011-2020 period. This process yields a future growth rate that assumes continued energy efficiency improvement at the level embedded in the hybrid regression data, with the first 16 years of regression data being net of EE and the next four being grossed up for EE. Because more of the data points are net, the forecast may be closer to a net than a gross, depending on how the effects on energy efficiency varied over time. To illustrate this point, consider the two examples below. The first example focuses only on the use of net historical data; the second accounts for some of the historical data being gross.

Example 1: If the economic growth rate was 2% per year, and continuous energy efficiency improvement reduced the amount of energy consumed per dollar of economic output by 1% per year, the net load growth rate would have been only 1%. A regression-based load forecast would then extrapolate this 1% load growth rate forward, if future economic growth rates are expected to continue at 2%. Yet the only way to maintain a 1% load growth rate in the face of 2% economic growth would be to continue the rate of efficiency improvement at the same historical rate of 1%. Thus, the load forecast would implicitly count on new energy efficiency measures and generally new efficient technology replacing old just like in the past.

Example 2: Again assume that the load has been growing at a constant rate of 1% net of EE, due to 2% economic growth and 1% annual reduction in energy consumed per dollar of economic output. The annualized growth rate of 1% for the 15 year window in the 1991-2006 period would be 1%. However, if the load is grossed up for the new EE program impacts in the 2007-2010 period, the load growth for this period is 2%. Thus the weighted average growth rate throughout the combined period would be (15*0.01+3*0.02)/18 = 1.2%. This implies that ISO-NE's approach would forecast the future load with a growth rate of 1.2% and then would adjust for the cumulative energy efficiency impacts (relative to 2006) in the forecast period. If a 1% future efficiency improvement is then subtracted from this hybrid rate, it would appear that net load would increase at only 0.2%, which would be artificially low.

In spite of the hybrid nature of the regression data, ISO-NE treats the model's forecast as if it were a pure "gross" forecast. ISO-NE subtracts the impacts of energy efficiency cleared in all

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8 Energy efficiency and other demand resources including load management and distributed generation projects received capacity credit during the capacity market transition period, 2007 through 2010. After 2010, energy efficiency was part of passive demand resources (PDR) that bid into the forward capacity market.

9 Energy efficiency impacts in the 2007-2010 period represents the cumulative EE impacts relative to 2006. Since NEL is grossed up for all cumulative efficiency relative to 2006 in the 2007-2010 period, at that point the gross NEL only includes the impacts of EE programs through 2006.

forward capacity auctions (with all impacts defined cumulative relative to 2006) to obtain its "net" forecast. This approach partially overstates the effects of new EE since the "gross load" is not a true gross.

Implications for the IRP Base Case

ISO-NE's "gross" forecast already partially accounts for the effects of future EE on the load growth rate. Deducting *all* future EE would partially double-count the effects of EE and thus understate future net load. One way to estimate the net load would be to *partially* deduct future EE from the load forecast. However, determining the appropriate deduction would require knowing the extent to which future EE is already embedded in the "gross" forecast due to the extrapolation of historical data. That was not possible given the lack of available data on the effects of past EE on metered loads between 1991 and 2006.

Hence, we decided to fully count energy efficiency cleared through FCA5 in the IRP modeling system, without further counting any Base Case energy efficiency planned for the 2015 to 2022 period. This approach likely achieves approximately the right effect of the Base Case level of EE in the long-run, with no known bias any errors are probably within the larger errors inherent in load forecasting during these economically uncertain times. This approach also has the advantage that it is consistent with ISO-NE's 10-year "net" forecast.

When evaluating the Expanded EE resource scenario, we count all savings that are incremental to the Base Case amount of EE. The net load in that scenario becomes the Base Case load minus the incremental savings. This approach presumes that the Base Case load forecast accurately reflects the Base Case amount of EE.

CONNECTICUT AND ISO-WIDE RELIABILITY REQUIREMENTS

The ISO-NE has developed several requirements to ensure the procurement of sufficient capacity to reliably meet expected load. For Connecticut, the ISO imposes a local sourcing requirement (LSR) to ensure it procures enough capacity within its zone. The LSR is set by the greater (i.e. more stringent) of the probabilistically-calculated Local Resource Adequacy (LRA), or the deterministically-calculated Transmission Security Analysis (TSA). For the ISO, the Installed Capacity Requirement (ICR) is an ISO-wide requirement to meet a one day in ten years loss-of-load expectation (LOLE). In addition, Connecticut must also ensure it has enough quick-start capacity to recover from on outage of one of the generation units at Millstone (the single largest "second contingency" event in the TSA analysis).[10]

Connecticut TSA and LRA

All load serving entities (LSEs) in Connecticut must procure sufficient capacity to meet their peak load share of the ICR which helps the region as a whole meet the ICR. However, the ISO also imposes an additional LSR to ensure that sufficient capacity is *physically located* in a sub-area to maintain local reliability when transmission limitations might prevent outside generation from serving local loads.

[10] The largest first contingency is the import limit.

The greater of ISO's two local requirement calculations (TSA and LRA) is explicitly enforced in the capacity market as Connecticut's LSR. The ISO calculates Connecticut's LRA using a probabilistic analysis of expected Connecticut system conditions. Because the LRA is historically relatively less stringent and particularly nuanced and difficult to re-calculate given different load, transmission, and resource assumptions, we base our analysis of Connecticut's resource adequacy solely on the historically stricter CT TSA to define Connecticut's local needs.

The ISO has relied on the TSA to determine the reliability impact of existing resources "de-listing" from the FCAs and not committing themselves as capacity resources. The ISO has several methodologies for determining the TSA requirement, but primarily uses its deterministic operable capacity analysis when evaluating local reliability in the capacity market. This, in part, results in a local requirement which is essentially the ISO's 90/10 peak load forecast plus the loss of the single largest generation contingency with one transmission line already out of service.[11] In Connecticut, that contingency is generally an unplanned outage of Millstone 3, or 1,225 MW. Based on the ISO's methodology requirements, resources, and resource adequacy under the CT TSA is expressed in terms of unforced, or derated, capacity.[12]

Figure 3 shows the estimated TSA reliability requirements for the Connecticut area in the Base Case. In estimating the TSA requirement, we assume several transmission upgrades in the Connecticut sub-area that increase the import limit during the study period. The New England East-West Solution (NEEWS), is a series of projects designed to improve system reliability and increase power flows from east to west in New England, which include thermal, voltage, and transfer import capabilities.[13] The Connecticut NEEWS-related upgrades include:

- The Greater Springfield Reliability Project, which increases Connecticut import limit by 100 MW in 2014
- The Interstate Reliability Project, which increases Connecticut import limit by 800 MW in 2016.
- The Central Connecticut Reliability Project, which increases Connecticut import limit by 200 MW in 2017.In addition, the Interstate Reliability Project will connect the combined cycle generators at Lake Road into the Connecticut electric grid. These upgrades are planned to be fully online by January 2016.

Two of the components of NEEWS — the Rhode Island Reliability Project and the Greater Springfield Reliability Project — are currently under construction. However, the remaining two components — the Interstate Reliability Project and the Central Connecticut Reliability Project

[11] For more detail please see: http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2011/jan132011/fca5_tsa_reqt_011811_rc.pdf.

[12] Unforced or derated capacity reflects the impact of random outages, and is always smaller than installed capacity measures.

[13] Other Transmission upgrades assumed include: second Deerfield autotransformer (2012), long-term Southeastern Massachusetts upgrades (2013), Rhode Island Reliability Project (2013), Central/Western Massachusetts upgrades (2012), Maine Power Reliability Program (2015), and the Greater Rhode Island Transmission Reinforcements (2015).

— are not yet under construction. They were included in the IRP Base Case because they received the required ISO-NE technical approvals. However, the state siting boards have yet to review the siting impacts and the reliability need for these projects. State siting reviews will be informed by ISO-NE's forthcoming reliability assessment, which will be updated to account for currently-projected system conditions. State siting hearings for the Interstate Project are underway in Connecticut and will be filed soon in Massachusetts and Rhode Island. State siting permit applications for the Central Connecticut project have not yet been filed.

If the Interstate and Central Connecticut projects are not approved, the Connecticut import capability would be 1,000 MW less than assumed for years 2016 through 2022 in the IRP Base Case, and the 745 MW Lake Road generating facility would not be incorporated electrically into Connecticut. Local resource adequacy would still be maintained, but with a smaller surplus of only approximately 200 MW between 2016 and 2022 (compared to 1,900-2,000 MW in the Base Case).

Figure 3
Base Case Estimated Local Reliability Requirements in Connecticut based on TSA

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Connecticut Requirement under Transmission Security Analysis	***(MW)***	**7,379**	**7,389**	**7,509**	**6,687**	**6,568**	**6,693**	**6,788**	**6,887**	**6,984**	**7,084**
Connecticut Sub-Area 90/10 Peak Load	*(MW)*	8,035	8,145	8,250	8,360	8,445	8,550	8,630	8,710	8,791	8,872
Additional Required Reserves (Millstone Unit 3)	*(MW)*	1,225	1,225	1,225	1,225	1,225	1,225	1,225	1,225	1,225	1,225
Additional Requirement for Installed Capacity Derate	*(MW)*	746	747	694	653	668	690	705	727	742	762
Reduction per Connecticut Import Limit	*(MW)*	2,500	2,600	2,600	3,400	3,600	3,600	3,600	3,600	3,600	3,600

Note: This is the TSA requirement expressed in ICAP terms for easier comparison. By doing this, all requirements, resources, and resource surpluses or gaps under the ICR, LRA, and CT TSA are consistently expressed in terms of installed capacity, or ICAP.

In addition to Connecticut, the ISO also calculates local reliability requirements for the Boston area. Although we do not address local resource adequacy outside of Connecticut, this Boston requirement is important for modeling and will be addressed later in the capacity market analysis section.

In the ISO's capacity market, if there is insufficient capacity physically located in a sub-area, the local requirement could "bind" in the Forward Capacity Market, and the local clearing price would rise above the ISO-wide clearing price. This would result in the sub-area's consumers paying the higher local price on a portion of their ICR equal to the greater of the LRA, or the TSA.

ISO-NE Capacity Requirement

The Installed Capacity Requirement (ICR) is an ISO-wide requirement to meet a one-day-in-ten-years loss-of-load expectation, which the ISO calculates using a probabilistic analysis of load uncertainty, resource availability, and tie benefits from neighboring regions. The resulting reserve margins vary from 14.1 percent to 14.6 percent for the years 2011 through 2020.[14] An ICR for any given year is continuously updated by the ISO as it receives new information about

[14] Resources to meet the ICR are procured through the ISO's Forward Capacity Market (FCM), through auctions starting three years prior to the capacity delivery year. 2021 and 2022 ICR values are extrapolated applying the 2020 pool reserve margin to the load forecast.

expected load and system conditions. In this report, we use the most updated information available, although ICR values will likely be adjusted by the ISO in the near future. Figure 4 shows the ISO-wide ICR.

Figure 4
ISO-NE Actual and Representative Installed Capacity Requirements

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ISO-NE 50/50 Peak Load	***(MW)***	**28,525**	**28,970**	**29,380**	**29,775**	**30,155**	**30,525**	**30,875**	**31,215**	**31,559**	**31,906**
Net Installed Capacity Requirement	***(MW)***	**32,547**	**33,200**	**33,618**	**34,059**	**34,483**	**34,887**	**35,267**	**35,635**	**36,027**	**36,424**
Installed Capacity Requirement (adds back HQICC)	*(MW)*	33,463	34,154	34,572	35,013	35,437	35,841	36,221	36,589	36,981	37,378
HQICC	*(MW)*	916	954	954	954	954	954	954	954	954	954
Other Tie-Line Benefits (NY & NB)	*(MW)*	778	729	729	729	729	729	729	729	729	729
Pool reserve	*(%)*	14.1%	14.6%	14.4%	14.4%	14.4%	14.3%	14.2%	14.2%	14.2%	14.2%

Since the 2010 IRP, the calculation methodology for the net ICR has changed. This is apparent by comparing the net ICRs reported in the ISO's 2010 and 2011 Regional System Plans for the 2014/15 delivery year. In the 2010 ISO-NE Regional System Plan (RSP) the peak load forecast was estimated at 29,025 and the corresponding net ICR value was 32,672.[15] However, in the 2011 RSP, the peak load forecast decreased to 28,970 while the net ICR value increased to 33,200.[16]

ISO-NE changed the ICRs in March 2011, when it revised its procedures for calculating tie-benefits. Tie benefits are estimates of available resources in neighboring control areas that may be drawn upon during emergency conditions. The ISO's methodology to calculate tie benefits was revised to include: (1) the modeling of transmission constraints internal to New England and its neighboring Control Areas that impact the ability of neighboring Control Areas to provide emergency assistance to New England and the ability of New England to make use of that emergency assistance, (2) changes to the manner in which capacity imports are accounted for in the tie benefits calculation, and (3) the calculation of tie benefits for individual interconnections, in addition to the calculation of tie benefits at the system-wide level and for each of the directly interconnected neighboring Control Areas of New Brunswick, New York, and Quebec.[17,18,19] Another significant change in the calculation was the application of load skewness in its loss of load expectation model in times of surplus. These changes resulted in an increase in the net ICR relative to peak load, and a resulting increase in reserve margins from about 11-12% to about 14-15% above peak loads.

[15] 2010 RSP available at http://www.iso-ne.com/trans/rsp/2010/rsp10_final.docx, page 35.

[16] 2011 RSP available at http://www.iso-ne.com/trans/rsp/2011/rsp11_final_102111.doc, page 42.

[17] ISO-NE methodology modification for calculating tie benefits available at http://www.iso-ne.com/regulatory/ferc/filings/2010/dec/er11-2580-000_12-30-10_tie_benefits.pdf.

[18] FERC approval of tie line benefits change available at http://www.iso-ne.com/regulatory/ferc/orders/2011/feb/er11-2580-000_2-28-11_order_tie_benefits.pdf.

[19] ISO-NE proposed ICR values available at http://www.iso-ne.com/regulatory/ferc/filings/2011/mar/er11-3048-000_03-08-11_icr_2014-2015.pdf.

Connecticut LFRM Requirement

To meet the fourth reliability requirement considered in this IRP — Connecticut's LFRM requirement — both Southwest Connecticut and Greater Connecticut must provide local second contingency coverage in the form of non-spinning 30-minute reserves. The ISO's 2011 RSP indicates that through 2015, Southwest Connecticut will have no LFRM requirement while Greater Connecticut may have a need of 400 to 1,000 MW.

Projected supply is more than adequate, with 949 MW in Southwest Connecticut, and 1,501 MW available to meet Greater Connecticut needs. The 506 MW of peaker generation contracts DPUC recently sponsored have contributed to this supply. Figure 5 shows the resources available to meet each area's requirement under LFRM. Resources in Southwest Connecticut can meet both Southwest Connecticut's requirement and the greater Connecticut requirement.

With more than adequate supply projected, LFRM prices are estimated to be zero or near-zero.

Figure 5
Resources Available to Meet SWCT and Greater Connecticut LFRM Requirements

Unit Name	Unit Status	RSP Area	Winter Claimed Capability *(MW)*	Summer Claimed Capability *(MW)*	Unit Type	In-Service Date	Notes
BRIDGEPORT HARBOR 4	Existing	SWCT	20	17	GT	1-Oct-67	
BRANFORD 10	Existing	SWCT	21	16	GT	1-Jan-69	
COS COB 10	Existing	NOR	23	19	GT	1-Sep-69	
COS COB 11	Existing	NOR	23	19	GT	1-Jan-69	
COS COB 12	Existing	NOR	23	19	GT	1-Jan-69	
DEVON 10	Existing	SWCT	19	14	GT	1-Apr-88	
DEVON 11	Existing	SWCT	39	29	GT	1-Oct-96	
DEVON 12	Existing	SWCT	38	29	GT	1-Oct-96	
DEVON 13	Existing	SWCT	39	30	GT	1-Oct-96	
DEVON 14	Existing	SWCT	40	30	GT	1-Oct-96	
NORWALK HARBOR 10 (3)	Existing	NOR	17	12	GT	1-Oct-96	
PPL WALLINGFORD UNIT 1	Existing	SWCT	48	42	GT	31-Dec-01	
PPL WALLINGFORD UNIT 2	Existing	SWCT	49	41	GT	7-Feb-02	
PPL WALLINGFORD UNIT 3	Existing	SWCT	48	42	GT	31-Dec-01	
PPL WALLINGFORD UNIT 4	Existing	SWCT	47	42	GT	23-Jan-02	
PPL WALLINGFORD UNIT 5	Existing	SWCT	49	41	GT	7-Feb-02	
WATERSIDE POWER	Existing	NOR	73	72	GT	1-May-04	
PIERCE STATION	Existing	SWCT	97	76	GT	1-Oct-07	
COS COB 13	Existing	NOR	23	19	GT	29-May-08	
COS COB 14	Existing	NOR	23	20	GT	29-May-08	
ROCKY RIVER	Existing	SWCT	29	29	PS	1-Jan-28	
JOHN STREET #3	Existing	SWCT	2	2	IC	26-Sep-07	
JOHN STREET #4	Existing	SWCT	2	2	IC	26-Sep-07	
JOHN STREET 5	Existing	SWCT	2	2	IC	1-Nov-07	
WATERBURY GENERATION FACILITY	Existing	SWCT	100	98	GT	21-May-09	
DEVON 15	Existing	SWCT	49	47	GT	12-Jul-10	
DEVON 16	Existing	SWCT	49	47	GT	28-Jun-10	
DEVON 17	Existing	SWCT	49	47	GT	15-Jun-10	
DEVON 18	Existing	SWCT	49	47	GT	9-Jun-10	
SW Connecticut (including Norwalk) Subtotal:			**1,092**	**949**			
FRANKLIN DRIVE 10	Existing	CT	21	15	GT	1-Nov-68	
MIDDLETOWN 10	Existing	CT	22	17	GT	1-Jan-66	
NORWICH JET	Existing	CT	19	15	GT	1-Sep-72	
SO. MEADOW 11	Existing	CT	47	36	GT	1-Aug-70	
SO. MEADOW 12	Existing	CT	48	38	GT	1-Aug-70	
SO. MEADOW 13	Existing	CT	48	38	GT	1-Aug-70	
SO. MEADOW 14	Existing	CT	46	37	GT	1-Aug-70	
TORRINGTON TERMINAL 10	Existing	CT	21	16	GT	1-Aug-67	
TUNNEL 10	Existing	CT	22	17	GT	1-Jan-69	
MONTVILLE 10 and 11	Existing	CT	5	5	IC	1-Jan-67	
MIDDLETOWN 12 - 15	Existing	CT	188	188	GT	1-Jun-11	
PSEG NEW HAVEN	Planned	CT	146	130	GT	1-Jun-12	[1]
Rest-of-Connecticut Subtotal:			**632**	**552**			
Available for SW Connecticut LFRM:			**1,092**	**949**			
Available for Greater Connecticut LFRM:			**1,724**	**1,501**			

Sources and Notes:
Source: 2011 CELT; excludes a small amount of new capacity (16 MW) with no resource name.
[1]: Peaking generation RFP winner; values based on executed contracts filed at CT DPUC.
Unit Types Include: Gas Turbine (GT), Internal Combustion (IC), and Pumped Storage (PS) units
RSP Areas included are Southwest Connecticut (SWCT), Norwalk (NOR) and Rest of Connecticut (CT)

EXISTING, PLANNED, AND ASSUMED FUTURE RESOURCES

To meet the ICR and CT TSA reliability requirements we first consider "known" generating and demand-side resources, which are either existing or planned based on currently available information. These resources may already be committed in the capacity market (through FCA5), contracted or permitted (such as state-contracted resources or renewable projects in the early stage of development), proposed but quantified with some decrement to reflect less than 100 percent expected development rates (such as proposed renewables to meet RPS), or otherwise extrapolated to reflect expected continuation of current levels (such as EE). We also consider assumed future resources such as projected renewables based on our "business as usual" trend.

Generation

Existing generation online as of June 1, 2011 is documented in the ISO's 2011 CELT. The amount of additional planned new generation is estimated using information from several sources, including results from the ISO's FCAs, projects listed in the ISO generation interconnection queue, state docket and RFP information, publicly-available information on generation development and contracting, and other third-party data. Only projects cleared in FCM, under construction, or contracted have been counted in this IRP for meeting future reliability needs, with the exception of additional assumed new renewable generation to meet RPS requirements. Currently there are 8,150 MW available generation resources in the Connecticut sub-area and 32,027 MW available ISO wide to meet reliability requirements.

The non-RPS planned additions include the New Haven Harbor gas turbine plant in the Connecticut area to come online 6/1/2012 at 130 MW. There is also a planned 22 MW upgrade to all 4 Northfield Mountain units for a total of 88 MW by 2015.

Figure 6 shows the current projects we assume are developed from Project 150 contracts as well as additional renewable projects that are currently planned or in development. A total of 69 MW (capacity value) are assumed to come online between now and 2017.

Figure 6
Planned RPS Projects
(Capacity Value MW)

	2013 *(MW)*	2014 *(MW)*	2015 *(MW)*	2016 *(MW)*	2017 *(MW)*	2018 *(MW)*	2019 *(MW)*	2020 *(MW)*	2021 *(MW)*	2022 *(MW)*
Connecticut Planned Renewables										
Project 150										
Plainfield Renewable Energy (Biomass)	0	0	0	0	30	30	30	30	30	30
DFC-ERG Milford (Fuel Cells)	0	0	9	9	9	9	9	9	9	9
Hospital Energy Development - Waterbury Hospital (Fuel Cells)	0	0	2	2	2	2	2	2	2	2
Hospital Energy Development - Stamford Hospital (Fuel Cells)	0	0	5	5	5	5	5	5	5	5
ISO Planned Renewables										
Onshore Wind	23	23	23	23	23	23	23	23	23	23
Total Connecticut Planned Renewables	0	0	16	16	46	46	46	46	46	46
Total ISO Planned Renewables	23	23	39	39	69	69	69	69	69	69

Sources and Notes:
Onshore wind has been derated to a capacity value of 19% and solar to 40%.

As discussed in detail in the Renewables Section it is projected that ISO-NE will develop an additional 766 MW in capacity credit-eligible renewables to meet the region's Renewable Portfolio Standards. This is in addition to the 69 MW (also in capacity value) of new planned renewables ISO-wide previously mentioned as "known" resources. Figure 7 shows a summary of the nameplate MW and the corresponding capacity value MW of the additional projected renewables. Together, planned and projected new renewables for RPS are projected to be eligible for 835 MW in capacity credit by 2022.

Figure 7
Projected New Renewables for RPS in Base Case
(Nameplate and Capacity Value MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
New England (NE)										
Biomass/Biofuels	106	106	111	111	111	111	111	111	111	111
Fuel Cells	6	11	17	22	26	26	26	26	26	26
Small Hydro	1	2	2	2	2	2	2	2	2	2
Landfill Gas	3	3	4	4	4	4	4	4	4	4
Onshore Wind	202	249	327	445	563	682	797	913	1,028	1,143
Offshore Wind	0	0	486	486	486	486	486	486	486	486
Solar PV	109	186	255	354	458	567	627	688	695	697
Total NE Projected (Nameplate MW) [a]	427	556	1,201	1,424	1,651	1,878	2,054	2,230	2,353	2,470
Additional Planned [b]	124	124	140	140	170	170	170	170	170	170
Total NE Projected @ Capacity Value [c]	**0**	**0**	**424**	**491**	**560**	**626**	**672**	**718**	**743**	**766**
Additional Planned [b]	0	0	39	39	69	69	69	69	69	69
Connecticut (CT)										
Biomass/Biofuels	0	0	0	0	0	0	0	0	0	0
Fuel Cells	6	11	17	22	26	26	26	26	26	26
Small Hydro	0	0	0	0	0	0	0	0	0	0
Landfill Gas	3	3	3	3	3	3	3	3	3	3
Onshore Wind	4	6	9	12	16	20	21	21	22	22
Offshore Wind	0	0	0	0	0	0	0	0	0	0
Solar PV	42	81	123	169	218	273	279	285	291	291
Total CT Projected (Nameplate MW) [a]	56	102	153	206	264	323	329	336	342	343
Additional Planned [b]	0	0	16	16	46	46	46	46	46	46
Total CT Projected @ Capacity Value [c]	**0**	**0**	**71**	**95**	**120**	**143**	**145**	**148**	**150**	**150**
Additional Planned [b]	**0**	**0**	**16**	**16**	**46**	**46**	**46**	**46**	**46**	**46**

Sources and Notes:
[a]: Projected includes additional resources assumed developed to meet RPS.
[b]: Planned includes resources contracted under Project 150, and resources currently under construction.
[c]: Capacity value for 2013 and 2014 is assumed zero since these resources are not currently committed under FCA4 and FCA5. Onshore wind is derated to a capacity value of 19%, offshore wind to 26%, and solar to 40%. All other resources are assumed to receive full capacity value.

We also assume several units will retire in ISO-NE based on publicly-available information. Salem Harbor has stated that it will retire, and ISO has accepted delist bids and non-price retirement requests for units 1 and 2. Salem Harbor units 3 and 4 had their non-price retirement

request rejected, but Dominion announced they would retire by 6/1/2014 due to the uncertainty and financial risks associated with future operations.

Figure 8
Units Planned to Retire

Unit Name	Unit Type	Reason	Capacity *(MW)*	Note
Salem Harbor 1	Coal	Non-Price Retirement	80	[1]
Salem Harbor 2	Coal	Non-Price Retirement	78	[1]
Salem Harbor 3	Coal	Non-Price Retirement	150	[2]
Salem Harbor 4	Oil	Non-Price Retirement	437	[2]
Vermont Yankee	Nuclear	Expired Operating License	604	[3]
AES Thames	Coal	Not Currently Operating	183	
Holyoke 8/Cabot 8	Oil	Non-Price Retirement Request	9	[4]
Holyoke 6/Cabot 6	Oil	Non-Price Retirement Request	9	[4]
Total			**1,549**	

Sources and Notes:
[1] http://www.iso-ne.com/genrtion_resrcs /reports/non_prc_retremnt_lttrs/2011/551_npr_determination.pdf
[2] http://www.iso- ne.com/genrtion_resrcs /reports/non_prc_retremnt_lttrs/2011/salem_retirement_election.pdf
[3] Legislation has not extended license to operate
[4] http://www.iso- ne.com/genrtion_resrcs /reports/sts_non_retrmnt_rqst/npr_tracking_external_10312011.pdf

Demand-Side Resources

Demand-side resources include Active Demand Resources (Active DR), and Passive Demand Resources (Passive DR), which are primarily composed of energy efficiency. Figure 9 summarizes the Base Case demand-side resources that are counted as supply toward the resource adequacy requirement. The Load Forecasting section of this Appendix explains why we are counting the full amount of Passive DR that has cleared in the forward capacity auctions but no additional energy efficiency beyond that amount.

Figure 9
Base Case Known Demand Resources

Demand Resource (DR) Type		ISO-Wide [1]		Connecticut Subarea [2]	
		2013/14 FCA4	2014/15 FCA5	2013/14 FCA4	2014/15 FCA5
Real Time Demand Response (RT DR)	[a]	1,363	1,382	312	307
Real Time Emergency Generation (RT EG)	[b]	688	722	239	257
On Peak	[c]	970	1,134	110	102
Seasonal Peak	[d]	328	352	299	317
Total DR Cleared in FCA4 & FCA5	[e]	3,349	3,590	961	983
RT EG, at 600 MW cap	[f]	600	600	208	214
RT EG proration to cap	[g]	87%	83%	87%	83%
Total Active DR (with RT EG at cap)	[h]	1,963	1,982	520	521
Total Passive DR	[i]	1,298	1,486	410	419
Total Known DR for Resource Adequacy	**[j]**	**3,261**	**3,468**	**930**	**940**

Sources and Notes:
FCA4 and FCA5 auction results from ISO-NE. See www. iso-ne.com.
[2]: Includes resources cleared for the three RSP Connecticut subareas.
[e]: Sum of [a] through [d].

Assumed additional Energy Efficiency in Boston

The Boston area is projected to need additional resources under its LSR by 2016, driven by the planned retirement of Salem Harbor and projected load growth. By 2022 it is projected that Boston will need 533 MW of additional capacity to meet its LSR. To meet these needs, it is assumed that Massachusetts energy efficiency programs will develop enough peak load reduction to meet the Boston LSR gap through 2022, although other resources could have been assumed instead; or a transmission solution could have been assumed, with different implications for the supply-demand balance in the rest of the region, and that possibility is examined as part of the Tight Supply future.[20,21]

[20] The amount of additional EE development assumed in Boston is consistent with (less than) the amount of incremental energy efficiency that would be achieved if Massachusetts meets the goals articulated in the Massachusetts Green Communities Act. However, this IRP does not otherwise assume completion of Massachusetts' ambitious EE goals. Doing so would require stronger assumptions on the amount of EE already included in the CELT load forecast and stronger assumptions about funding Massachusetts will commit for EE in the future.

[21] In the Tight Supply future, the Boston Import interface has a limit 1000 MW higher than in the base case. The 1000 MW increase represents an assumption that ISO-NE and Massachusetts would not allow this to occur, and would use transmission upgrades to prevent the situation.

Net Imports from Outside New England

Known imports include external generating resources cleared in the capacity auctions for years 2013 and 2014. In FCA4 1,993 MW imports cleared for the 2013/14 delivery year, and in FCA5 2,011 MW cleared for the 2014/15 delivery year. Imports are assumed constant at 2,011 MW for years 2015 through 2022. One generating unit within the ISO, Cockwell 1, has de-listed 100 MW in the capacity market as a firm export. This export reflects the unit's long-term contract with Long Island Power Authority to deliver power on the Cross Sound Cable line. We assume this firm export from the ISO system for each year 2013 through 2022.

PROJECTED ECONOMIC RETIREMENT, ENTRY, AND ACTIVE DR

Most of the existing and potential capacity supply in New England is controlled by market participants. Their exit and entry decisions can only be projected by modeling their financial decisions, which are presumably based on their expected costs and market-based revenues. This section describes how the IRP simulates such decisions, including how costs are estimated, and how energy and capacity revenues are projected.

Capacity Market Modeling

The Brattle Group's capacity market model simulates ISO-NE capacity market auctions and economic entry/exit decisions simultaneously, since the capacity prices both influence individual economic decisions *and* reflect the combined results of those decisions. In the model, the demand for capacity is given by ISO-NE NICR projections. Supply includes most existing/planned generation bidding as price-takers, offering capacity at zero price and accepting whatever price results. Retirement candidates, Active DR[22] resources, and potential new entrants submit bids that reflect their net avoidable going-forward costs.

The model solves for a capacity price trajectory for the years 2015-2030. Prices are set by the bid price of the marginal unit (a retirement or mothball candidate, Active DR, or new entrant), or the administrative price floor. At the "optimum," each generating unit is making profit-maximizing short-term decisions (operate versus mothball) and long-term decisions (invest in assumed environmental controls versus retire). DR is similarly making annual profit-maximizing decisions, as described below.

The capacity model is also linked to the DAYZER energy market model: supplier entry and exit decisions and their capacity market bids depend on their expected energy margins. Likewise, the energy market analysis relies on retirement and new generic build results from the capacity market analysis. To achieve internal consistency, the two models are run iteratively until they are consistent with each other.

[22] "Active DR" refers to end-use customers (or aggregations thereof) that receive credit as capacity supply for committing to reduce their load by a specified amount when called by ISO-NE. ISO-NE will call Active DR resources only in the event of a system emergency, when all committed generation is already operating at maximum output. Active DR is distinguished from "Passive DR," which includes energy efficiency.

Economic Analysis of Existing Generating Units Retrofit vs. Retire Decisions

Decision Framework

In determining whether a generation unit would continue to operate or retire, we consider the net present value (NPV) of its going-forward revenues and costs. Revenues include capacity market revenues from the capacity model, and energy margins estimated using the DAYZER model. Going-forward costs include annual fixed operating and maintenance (FOM) costs, and the capital costs of any required retrofits needed to comply with environmental regulations.

The NPV analysis follows the standard all-equity, after-tax, discounted cash flow methodology: calculate all-equity cash flows for each year, then discount them at the after-tax weighted average cost of capital (ATWACC). Because the ATWACC accounts for the cost of equity, and the cost of debt including the debt tax shield, the annual cash flows need not account for interest payments or their effect on taxes, hence the name "all-equity cash flows."[23] Figure 10 shows the financing assumptions used in the capacity model. The discount rate assumed in the capacity model is an ATWAAC of 8.5%, consistent with a merchant generation project that is balance-sheet financed by a larger corporate entity.[24] Tax rates are a combination of federal and state income taxes that differ for each state in ISO New England.[25] The final tax rate accounts for a federal income tax rate of 35% and an average state tax rate of 8.2% (simple average state tax rate across all modeled units).[26]

Figure 10
Merchant Generation Financing Assumptions

Cost of Equity	12.5%
Cost of Debt	7.5%
Debt-to-Equity Ratio	50/50
Income Tax Rate	40.3%
ATWACC	8.5%

Each unit faces a two-part decision: (1) in each year would it be better to operate and incur any required capital costs or mothball, and (2) given the long-term outlook would it be better to permanently retire?

- **Mothball versus operate:** Prior to making a decision on permanent retirement, some units may find it more economic to mothball in a given year in order to either delay incurring major capital costs or to avoid losses in years with extremely low capacity prices. The retirement analysis includes as an initial step a year-by-year assessment of unit decisions to either mothball or operate. The

[23] For example, see p. 473 of Brealey, R., S. Myers, and F. Allen. (2010) *Principles of Corporate Finance.* McGraw-Hill.

[24] Nominal ATWAAC = 12.5% · 50% + 7.5% · 50% · (1 - 40.3%) = 8.5%.

[25] Federal income tax rate is 35%. State income tax rates are 7.5% for CT, 9.0% for RI, 8.5% for NH, 8.5% for VT, 8.93% for ME, and 8.25% for MA. See http://www.taxfoundation.org/taxdata/show/230.html

[26] The total income tax is 8.2% + (1 - 8.2%) · 35% = 40.3%.

annual cost to mothball a unit is assumed to be one-half of the ordinary fixed operating and maintenance (FOM) cost the unit incurs on an ongoing basis

- **Permanent retirement:** Using the results of the annual mothball versus operate decision, we calculate each unit's annual net revenue including only the cost to mothball in a mothball year, and during operations the capital cost of assumed emissions control installation if required, plus net operating costs.

Assumptions on Environmental Retrofit Costs

Appendix E (Environment) documents all assumptions on retrofits needed to comply with environmental regulations primarily focused on the new Mercury and Air Toxics Standards (MATS) rule. That appendix provides unit-specific information based on the following assumptions: oil-fired steam units need an electrostatic precipitator (ESP) as well as fuel monitoring to control mercury. Coal Units need activated carbon injection (ACI) as well as either a fabric filter (FF) or a cold ESP for mercury controls. Wet flue gas desulfurization (FGD), dry FGD, or dry sorbent injection (DSI) is needed to control acid gases.

Capital costs needed for MATS compliance are incurred in 2015, and upgrade costs cannot be delayed or avoided. Similar to already-announced controls, these controls incrementally increase FOM and VOM while decreasing emission rates. Costs vary depending plant size and heat rate (for ACI and DSI).[27] ESP costs range from $72/kW to $226/kW, DSI costs range from $52/kW to $154/kW and ACI costs from $23/kW to $34/kW. Assumed unit-specific costs and upgrades are documented in Appendix E.

Some units have publicly announced their controls and MATS compliance strategies. For these units we do not model any additional capital costs to continue operating (equivalent to assuming that the costs are sunk and the investment decision to stay online has already been made). These and other recently-installed controls were identified and emissions rates for these units have been updated compared to the 2010 IRP.

Assumptions on FOM Costs

FOM costs include property taxes, plant insurance, facility fees for operating labor and minor maintenance, and asset management costs. Plant-specific FOM costs are assumed to be accurately represented by data provided by Ventyx, as summarized in Figure 11.[28]

[27] For ESP costs see: http://www.epa.gov/ttn/atw/utility/cost_impacts_012304.pdf, page 7-8. For coal unit costs see http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html and http://www.epa.gov/airmarkets/progsregs/epa-ipm/toxics.html .

[28] Ventyx, The Velocity Suite.

Figure 11
Plant-Specific FOM Costs

Name	State	Capacity *MW*	FOM *$/kW-Yr*
AES THAMES	CT	183	29
BRIDGEPORT HARBOR 2&3	CT	514	26
MIDDLETOWN 2-4	CT	753	13
MONTVILLE 5&6	CT	488	13
NEW HAVEN HARBOR	CT	448	15
NORWALK HARBOR 1&2	CT	330	14
BRAYTON PT 1-4	MA	1,534	29
MT TOM	MA	143	47
SALEM HARBOR 1-4	MA	744	20
CANAL 1&2	MA	1,092	18
CLEARY 8	MA	26	15
HOLYOKE/CABOT 6&8	MA	18	12
KENDALL STEAM 1 2 3	MA	53	14
MYSTIC 7	MA	578	14
WEST SPRINGFIELD 3	MA	94	13
MEAD	ME	2	30
YARMOUTH 1-4	ME	820	11
MERRIMACK 1&2	NH	451	64
SCHILLER 4&6	NH	95	68
NEWINGTON 1	NH	400	21

Source: Ventyx, The Velocity Suite

New Entry Analysis

New generation is assumed to be built when market revenues are sufficient to cover the levelized Cost of New Entry (CONE). CONE was estimated using PJM's most recent CONE estimates for combustion turbines and combined cycle plants, conducted by The Brattle Group.[29] The report estimates costs of building a power plant in five different areas of PJM. Costs considered include capital costs (*e.g.*, equipment, engineering, procurement and construction costs, land, *etc.*) and fixed operation and maintenance costs (*e.g.*, property tax, insurance, *etc.*). Financing assumptions were estimated for a merchant generation project that is balance-sheet financed by a larger corporate entity.

The resulting costs were adapted to a New England context by escalating gas CC and CT costs 4.7% and 2.4% respectively, to account for higher labor costs.[30] A summary of costs are shown in Figure 12. Figure 13 shows the corresponding plant characteristics.

[29] PJM Interconnection, L.L.C., Docket No. ER12-513-000, filed Dec. 1, 2011, Attachment D, Exhibit 2: The Brattle Group, *Cost of New Entry Estimates for Combustion Turbine and Combined-Cycle Plants in PJM*, dated Aug. 24, 2011.

[30] See http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf escalation rates for gas CC and CT plants.

Figure 12
New Gas CC and CT Costs

		Gas CC	Gas CT
Total Plant Capital Cost	*($M)*	$609	$302
Net Summer ICAP	*(MW)*	656	390
Overnight Cost	*($/kW)*	$929	$759
FixedO&M	*($/kW-y)*	$17	$16
After-Tax WACC	*(%)*	8.5%	8.5%
Levelized Gross CONE			
Level Real	*($/kW-y)*	$138	$107
Level Nominal	*($/kW-y)*	$165	$129

Figure 13
Characteristics of New Generation Plants

Plant Characteristic	Simple Cycle	Combined Cycle
Turbine Model	GE 7FA.05	GE 7FA.05
Configuration	2 x 0	2 x 1
Net Plant Power Rating	Baseload: 418 MW at 59 °F 390 MW at 92 °F	Maximum Load (w/ Duct Firing): 701 MW at 59 °F 656 MW at 92 °F
Cooling System	n/a	Cooling Tower
Power Augmentation	Evaporative Cooling	Evaporative Cooling
Net Heat Rate (HHV)	Baseload: 10,094 btu/kWh at 59 °F 10,320 btu/kWh at 92 °F	Baseload (w/o Duct Firing): 6,722 btu/kWh 59 °F 6,883 btu/kWh 92 °F
NO_X Controls	Dry Low NO_X Burners Selective Catalytic Reduction Water Injection for DFO	Dry Low NO_X Burners Selective Catalytic Reduction Water Injection for DFO
Dual Fuel Capability	Distillate Fuel Oil	Distillate Fuel Oil
Blackstart Capability	None	None
On-Site Gas Compression	None	None

The location and technology type to install are dependent on the economics of the market. We assume that merchant generator companies will seek out sites and develop technologies corresponding to the area with the lowest net CONE (*i.e.*, where its net energy and ancillary revenues are the highest).

Entry and Exit of Active Demand Response

DR entry and exit were modeled based on the underlying concept that DR penetration levels should increase when capacity prices rise and decrease when capacity prices fall. DR penetration levels are therefore modeled based on a DR supply curve, which is based on estimated DR costs.

DR costs include the interruption costs for each call and fixed costs. Interruption costs are based on an expected interruption frequency and a reservation value of $5,000/MWh. The expected interruption frequency is a function of the load duration curve and the amount of other resources available to meet load. DR is interrupted when other resources are insufficient to meet load. DR fixed costs are assumed to increase linearly for each additional MW of DR. The DR supply curve is calibrated to match actual FCA5 results by adjusting the fixed cost parameter.

Capacity Market Analysis Results

Figure 14 shows the results of the capacity market analysis in the Base Case. Capacity Prices are expected to drop when the price floor is discontinued in 2016/17. In 2022/23 prices clear at net CONE at $7.1/kW-mo. The corresponding projections of retirements, active DR entry and exit, and new generation entry are shown in Figure 15. As Figure 15 shows, 1,700 MW of fossil steam generation retires, primarily the units assumed to need retrofits to comply with the Air Toxics rule in 2015. The unit-level details are show in

Figure 16. Meanwhile, demand response participation in the capacity market varies by -1,000/+600 MW relative to the amount cleared in FCA5, helping to keep the total supply in balance with demand. New generation entry is not needed or economic until 2022.

Figure 14
Projected Base Case Capacity Prices (2012$/kW-mo)

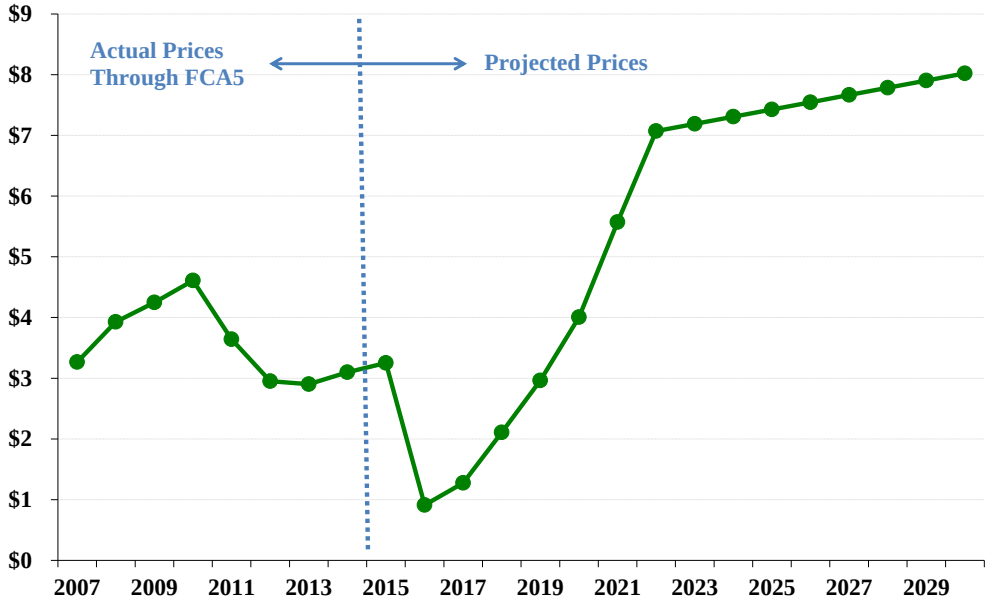

Figure 15
Summary of Resources Projected Based on Economics (Base Case)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Connecticut										
Additional projected economic retirements of existing generation capacity	(130)	(130)	(938)	(938)	(938)	(938)	(938)	(938)	(938)	(938)
Projected change in demand response in response to capacity prices	0	0	32	(258)	(209)	(126)	(66)	20	80	160
ISO-Wide										
Additional projected economic retirements of existing generation capacity	(132)	(132)	(1,252)	(1,687)	(1,687)	(1,687)	(1,687)	(1,687)	(1,687)	(1,687)
Projected change in demand response in response to capacity prices	0	0	119	(976)	(791)	(479)	(251)	76	303	606
Additional projected generic new generation assumed to meet ICR	0	0	0	0	0	0	0	0	0	62

Figure 16
Unit-Level Results

Unit Name	Summer Capacity (MW)	State	Retirement Projection	Notes
BRIDGEPORT HARBOR 2	130	CT	**Retire in 2013**	Estimated net revenues not high enough to continue to operate
MIDDLETOWN 2	117	CT	Operate	Has existing controls, estimated net revenues high enough to continue to operate
MIDDLETOWN 3	236	CT	Operate	Has existing controls, estimated net revenues high enough to continue to operate
MIDDLETOWN 4	400	CT	**Retire in 2015**	Must install an ESP. Estimated net revenues in later years are not enough to offset capital investment of ESP
MONTVILLE 5	81	CT	Operate	Has existing controls, estimated net revenues high enough to continue to operate
MONTVILLE 6	407	CT	**Retire in 2015**	No existing emission controls, assumed installation of an ESP
NEW HAVEN HARBOR	448	CT	Operate	Has existing controls, estimated net revenues high enough to continue to operate
NORWALK HARBOR 1	162	CT	Operate	Has existing controls, estimated net revenues high enough to continue to operate
NORWALK HARBOR 2	168	CT	Operate	Has existing controls, estimated net revenues high enough to continue to operate
BRAYTON PT 4	435	MA	**Retire in 2016**	Estimated net revenues not high enough to continue to operate
CANAL 1	573	MA	Operate	Has existing controls, estimated net revenues high enough to continue to operate
CANAL 2	545	MA	Operate	Has existing controls, estimated net revenues high enough to continue to operate
CLEARY 8	26	MA	Operate	Estimated net revenues high enough to continue to operate, no upgrades necessary
HOLYOKE 6/CABOT 6	10	MA	**Retire in 2015**	Non-price retirement request
HOLYOKE 8/CABOT 8	10	MA	**Retire in 2015**	Non-price retirement request
KENDALL STEAM	53	MA	Operate	Estimated net revenues high enough to continue to operate, no upgrades necessary
MYSTIC 7	578	MA	Operate	Has existing controls, estimated net revenues high enough to continue to operate
SALEM HARBOR 1	80	MA	**Retire in 2014**	Non-price retirement
SALEM HARBOR 2	78	MA	**Retire in 2014**	Non-price retirement
SALEM HARBOR 3	150	MA	**Retire in 2014**	Non-price retirement
SALEM HARBOR 4	437	MA	**Retire in 2014**	Non-price retirement
WEST SPRINGFIELD 3	94	MA	Operate	Has existing controls, estimated net revenues high enough to continue to operate
YARMOUTH 1	52	ME	**Retire in 2015**	Must install an ESP. Estimated net revenues in later years are not enough to offset capital investment
YARMOUTH 2	51	ME	**Retire in 2015**	Must install an ESP. Estimated net revenues in later years are not enough to offset capital investment
YARMOUTH 3	116	ME	**Retire in 2015**	Must install an ESP. Estimated net revenues in later years are not enough to offset capital investment
YARMOUTH 4	603	ME	Operate	Has existing controls, estimated net revenues high enough to continue to operate
NEWINGTON 1	400	NH	Operate	Has existing controls, estimated net revenues high enough to continue to operate
AES THAMES	183	CT	**Retire in 2013**	Not currently operating
MERRIMACK 1	113	NH	Operate	Has announced wet FGD upgrade, estimated net revenues high enough to continue to operate
MERRIMACK 2	338	NH	Operate	Has announced wet FGD upgrade, estimated net revenues high enough to continue to operate
BRIDGEPORT HARBOR 3	383	CT	Operate	Must install DSI for acid gas controls. Estimated net revenues high enough to continue operating
BRAYTON PT 1	244	MA	Operate	Has existing controls, estimated net revenues high enough to continue to operate
BRAYTON PT 2	244	MA	Operate	Has existing controls, estimated net revenues high enough to continue to operate
BRAYTON PT 3	612	MA	Operate	Has existing controls, estimated net revenues high enough to continue to operate
MT TOM	143	MA	Operate	Must install DSI for acid gas controls. Estimated net revenues high enough to continue operating
SCHILLER 4	48	NH	**Retire in 2015**	Must install ACI and DSI. Estimated net revenues in later years are not enough to offset capital investment
SCHILLER 6	48	NH	**Retire in 2015**	Must install ACI and DSI. Estimated net revenues in later years are not enough To offset capital investment
VERMONT YANKEE	604	NH	**Retire in 2013**	Assumed expired operating license

BASE CASE RESOURCE ADEQUACY OUTLOOK

Figure 17 and Figure 18 below show the resulting supply-demand balance for Connecticut and the ISO, respectively. Both are expected to have sufficient resources to meet reliability requirements through 2022.

Figure 17
Base Case Resource Adequacy Outlook under Connecticut TSA Requirement (MW)

Year		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Known and Extrapolated Supply & Demand Factors											
Connecticut Requirement under Transmission Security Analysis	[1]	7,379	7,389	7,509	6,687	6,568	6,693	6,788	6,887	6,984	7,084
CT Sub-Area Internal Installed Capacity	[2]	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150	8,150
Active DR Cleared in FCA4/5, then assumed constant	[3]	520	521	521	521	521	521	521	521	521	521
Passive DR Cleared in FCA4/5, then assumed constant	[4]	410	419	419	419	419	419	419	419	419	419
Existing Purchases & Sales	[5]	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100
Planned Additions	[6]	130	130	146	891	921	921	921	921	921	921
Connecticut Peaking Generation Contracts	[7]	130	130	130	130	130	130	130	130	130	130
Inclusion of Lake Road Units in CT	[8]	0	0	0	745	745	745	745	745	745	745
Planned Renewable Additions (including Project 150)	[9]	0	0	16	16	46	46	46	46	46	46
Planned Retirements *	[10]	(183)	(183)	(183)	(183)	(183)	(183)	(183)	(183)	(183)	(183)
Resources Available to Meet CT TSA Requirement	[11]	8,927	8,937	8,954	9,699	9,729	9,729	9,729	9,729	9,729	9,729
Net Subtotal	**[12]**	**1,548**	**1,548**	**1,445**	**3,012**	**3,160**	**3,035**	**2,940**	**2,841**	**2,745**	**2,645**
Projected Supply Variables											
Projected Renewable Additions for RPS	[13]	0	0	71	95	120	143	145	148	150	150
Projected Active DR Changes in CT as Capacity Prices Change	[14]	0	0	32	-258	-209	-126	-66	20	80	160
Projected Economic Retirements**	[15]	(130)	(130)	(938)	(938)	(938)	(938)	(938)	(938)	(938)	(938)
Resources Available to Meet CT TSA Requirement	[16]	8,796	8,807	8,119	8,598	8,702	8,807	8,870	8,958	9,021	9,101
CT Surplus (Shortfall)	**[17]**	**1,418**	**1,417**	**610**	**1,911**	**2,133**	**2,114**	**2,081**	**2,071**	**2,037**	**2,017**

Sources and Notes:

[1] Calculated based on the methodology listed on page 4 of the ISO-NE Transmission Security Analysis Requirement Values for 2012/13 ARA3 & 2013/14 ARA2.
[2] 2011 CELT Expected Summer Peak SCC, August 1, 2011.
[3] FCA4/5 Auction Results, then assumed constant (Real Time Demand Resources + RTEG pro-rated to NEISO FCM cap of 600MW).
[4] FCA4/5 Auction Results, then assumed constant (On Peak + Seasonal Peak Demand Resources).
[5] FCA5 Auction results, J. Cockwell 1 100MW administrative delist bid.
Reflects the LIPA contract for 100 MW capacity over Cross Sound Cable through 2018. Assumed in place in 2019-2022.
[6] [7]+[8]+[9]
[7] New Haven Harbor 2-4 Upgrade (130 MW)
[8] Assumes NEEWS in 2016, which would bring these Lake Road units electrically into Connecticut.
[9] Capacity Value of planned renewable generation as developed in Appendix D (Renewable Energy), including Project 150.
[10] AES Thames.
[11] [2]+[3]+[4]+[5]+[6]+[10]
[12] [11]-[1]
[13] Capacity Value of projected new renewable generation developed in Appendix D (Renewable Energy).
[14] Assumed economic changes in Active DR, developed in the "Projected Economic Retirement, Entry and Active DR" section of Appendix B (Resource Adequacy).
[15] Assumed economic retirements, developed in the "Projected Economic Retirement, Entry and Active DR" section of Appendix B (Resource Adequacy).
Includes Montville 6, Middletown 4 and Bridgeport Harbor 2.
[16] [11]+[13]+[14]+[15]
[17] [16]-[1]

Figure 18
Base Case Resource Adequacy under ISO-NE Net Installed Capacity Requirement (MW)

Year		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Known and Extrapolated Supply & Demand Factors											
ISO-NE 50/50 Gross Peak Load	[1]	28,525	28,970	29,380	29,775	30,155	30,525	30,875	31,215	31,559	31,906
Pool Reserve	[2]	14.1%	14.6%	14.4%	14.4%	14.4%	14.3%	14.2%	14.2%	14.2%	14.2%
Net ICR	[3]	**32,547**	**33,200**	**33,618**	**34,059**	**34,483**	**34,887**	**35,267**	**35,635**	**36,027**	**36,424**
Internal Installed Generating Capacity as of 5/31/2011	[4]	32,027	32,027	32,027	32,027	32,027	32,027	32,027	32,027	32,027	32,027
Active DR Cleared in FCA4/5, then assumed constant	[5]	1,963	1,982	1,982	1,982	1,982	1,982	1,982	1,982	1,982	1,982
Passive DR Cleared in FCA4/5, then assumed constant	[6]	1,298	1,486	1,486	1,486	1,486	1,486	1,486	1,486	1,486	1,486
Existing Purchases & Sales per ISO-NE in FCA4/5, then assumed constant	[7]	1,893	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911
Planned Additions	[8]	160	160	257	257	287	287	287	287	287	287
Connecticut Peaking Generation Contracts	[9]	130	130	130	130	130	130	130	130	130	130
Upgrades to Existing Capacity	[10]	30	30	88	88	88	88	88	88	88	88
Planned Renewable Additions (including Project 150)	[11]	0	0	39	39	69	69	69	69	69	69
Planned Retirements	[12]	(963)	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)
Total Resources Available to Meet Net ICR	[13]	36,378	36,017	36,114	36,114	36,144	36,144	36,144	36,144	36,144	36,144
Net Subtotal	**[14]**	**3,831**	**2,817**	**2,496**	**2,055**	**1,661**	**1,257**	**877**	**509**	**117**	**(280)**
Projected Supply Variables											
Projected Renewable Additions for RPS	[15]	0	0	424	491	560	626	672	718	743	766
Needed New Resources in Boston to Meet LSR (assume EE)	[16]	0	0	87	175	262	349	435	521	527	533
Projected Active DR Changes as Capacity Prices Change	[17]	0	0	119	-976	-791	-479	-251	76	303	606
Projected Economic Retirements	[18]	(132)	(132)	(1,252)	(1,687)	(1,687)	(1,687)	(1,687)	(1,687)	(1,687)	(1,687)
Projected Economic New Generation	[19]	0	0	0	0	0	0	0	0	0	62
ISO-NE Surplus (shortfall)	**[20]**	**3,699**	**2,685**	**1,875**	**58**	**5**	**66**	**47**	**138**	**3**	**0**

Sources and Notes:

[1] 2011 CELT 50/50 base economic growth peak load forecast through 2020 then extrapolated at the 2019-20 growth rate.
[2] ([3]-[1])/[1]
[3] 2013: 2013/14 2nd Annual Reconfiguation Auction.
2014-2020: 2011 ISO-NE Regional System Plan, table 5-1, page 42.
2021-2022: Extrapolated based on the 2020 Pool Reserve in the 2011 ISO-NE RSP.
[4] 2011 CELT Expected Summer Peak SCC, August 1, 2011, Excluding the Rollins Wind Plant (10 MW).
[5] FCA4/5 Auction Results, then assumed constant (Real Time Demand Resources + RTEG at FCM cap of 600MW).
[6] FCA4/5 Auction Results, then assumed constant (On Peak + Seasonal Peak Demand Resources).
[7] FCA4/5 Auction Results, then assumed constant (Cleared Imports net of J. Cockwell 1 100MW administrative delist bid).
[8] [9]+[10]+[11]
[9] New Haven Harbor 2-4 Upgrade (130 MW)
[10] Northfield Mountain Upgrade (88MW total, 30 MW cleared in FCA4/5).
[11] Capacity Value of planned renewable generation as developed in Appendix D (Renewable Energy), including Project 150.
[12] Vermont Yankee, Salem Harbor, AES Thames, and Holyoke 6 & 8.
[13] [4]+[5]+[6]+[7]+[8]+[12]
[14] [13]-[3]
[15] Capacity Value of projected new renewable generation developed in Appendix D (Renewable Energy).
[16] Assumed additional EE needed to meet Boston LSR, developed in the "Existing, Planned, and Assumed Future Resources" section of Appendix B (Resource Adequacy).
[17] Assumed economic changes in Active DR, developed in the "Projected Economic Retirement, Entry and Active DR" section of Appendix B (Resource Adequacy)
[18] Assumed economic retirements, developed in the "Projected Economic Retirement, Entry and Active DR" section of Appendix B (Resource Adequacy).
Includes 938 MW of ST/O in CT (Middletown 4, Montville 6, Bridgeport Harbor 2), 652 MW of ST/O outside CT (Yarmouth 1-3, Brayton Pt. 4), and 97 MW of ST/C outside CT (Schiller 4 & 6, Mead).
[19] Assumed new generation, developed in the "Projected Economic Retirement, Entry and Active DR" section of Appendix B (Resource Adequacy)
[20] ([13]+[15]+[16]+[17]+[18]+[19])-[3]

However, there are substantial uncertainties in forecasting market participants' retirement and entry decisions. For example, if more units have higher going-forward costs or more environmental retrofit requirements than assumed, more retirements could occur. Active DR could differ from forecast, as could the load itself. These types of possibilities are analyzed in the following section addressing alternative Futures, including one with "Tight Supply" conditions and another with "Abundant Supply" conditions.

As much as 550 MW additional resources could be needed in Connecticut in a very unlikely worst case where: (1) all fossil steam units retire; (2) the Central Connecticut portion of the New England East-West Solution is not constructed, reducing the import limit by 200 MW; (3) ISO-NE's "high economic growth" forecast is realized (about 350 MW higher in CT than the Base forecast by 2022); and (4) all 400 MW of old aero-derivative combustion turbines retired due to potential future NOx regulations. So many retirements are very unlikely for several reasons: first, we have not identified particular environmental requirements that would force these units to pay for costly environmental retrofits in order to continue to operate; second, based on the estimated capacity prices and going-forward costs for these plants, we anticipate that they would make more money by continuing to operate than not; and third, if more capacity retired than anticipated, capacity prices would tend to rise and provide a stronger signal for the remaining capacity to remain. Moreover, if market prices were insufficient to retain adequate capacity, ISO-NE would offer a reliability contract to individual units (and only one or two would be needed in the worst possible case described above). Nevertheless, Connecticut should monitor the situation and ensure measures would be in place to mitigate any shortfalls.

RESOURCE ADEQUACY IN ALTERNATIVE FUTURES AND RESOURCE SCENARIOS

Figures 19–22 show the components of supply and demand across all Futures and Resource Scenarios analyzed. (The assumptions underlying each case are described in the IRP report). In all Futures under the Base resource scenarios, we project that Connecticut will have sufficient capacity to meet its local resource adequacy requirements through 2022, with a surplus of 1,691 to 2,377 MW in 2022. ISO-NE could need new generation starting in 2018, growing to 2,122 MW by 2022 in the Tight Supply future with high economic growth, no increase in DR penetration, and no development of new energy efficiency in the Northeast MA / Boston area to meet local needs there.

Figures 19–22 also show how different amounts of energy efficiency, renewable generation, and/or new cost-of-service (COS) generation affect retirements, Active DR, and generic generation entry in the IRP modeling system. In most cases, the region has just sufficient resources, due to the way the forward capacity market clears. However, in the "New COS Gen High Minimum Offer Price (MOP)" Resource Scenarios, the region experiences a surplus in the Base, Abundant Supply, and High Gas Futures. With "High MOP," it is assumed that the unit's minimum offer price is set at the same level as a merchant combined cycle, so the unit does not clear if merchant entry is not yet economic. In the other Futures, merchant entry is economic, so the COS Gen plant clears and displaces other entrants.

Figure 19
Connecticut Resource Adequacy Parameters in 2022

Future	Resource Scenario	CT TSA *(MW)*	Existing Gen *(MW)*	Existing Purchases and Sales *(MW)*	Renewable Additions *(MW)*	Energy Efficiency *(MW)*	New COS Gen *(MW)*	Retired Capacity *(MW)*	Active DR *(MW)*	Net Surplus (Shortage) *(MW)*
Base Case	Base	7,084	9,025	-100	196	419	0	1,121	681	2,017
Tight Supply	Base	7,381	9,025	-100	196	419	0	990	521	1,691
Abundant Supply	Base	6,756	9,025	-100	196	419	0	1,504	587	1,868
High Gas	Base	6,572	9,025	-100	196	419	0	1,121	530	2,377
Low Gas	Base	7,399	9,025	-100	196	419	0	990	602	1,753
Base Case	Expanded EE	6,996	9,025	-100	196	1,576	0	1,121	550	3,131
Tight Supply	Expanded EE	7,310	9,025	-100	196	1,576	0	990	521	2,919
Abundant Supply	Expanded EE	6,666	9,025	-100	196	1,576	0	1,952	404	2,483
High Gas	Expanded EE	6,499	9,025	-100	196	1,576	0	1,898	413	2,713
Low Gas	Expanded EE	7,332	9,025	-100	196	1,576	0	1,373	620	2,612
Base Case	Exp. EE & RPS Class I Flex.	6,996	9,025	-100	196	1,576	0	1,121	550	3,131
Tight Supply	Exp. EE & RPS Class I Flex.	7,310	9,025	-100	196	1,576	0	990	521	2,919
Abundant Supply	Exp. EE & RPS Class I Flex.	6,666	9,025	-100	196	1,576	0	1,952	404	2,483
High Gas	Exp. EE & RPS Class I Flex.	6,499	9,025	-100	196	1,576	0	1,898	413	2,713
Low Gas	Exp. EE & RPS Class I Flex.	7,332	9,025	-100	196	1,576	0	1,373	620	2,612
Base Case	Full RPS Class I	7,081	9,025	-100	198	419	0	1,121	660	2,001
Tight Supply	Full RPS Class I	7,381	9,025	-100	199	419	0	990	521	1,693
Abundant Supply	Full RPS Class I	6,753	9,025	-100	197	419	0	1,504	569	1,853
High Gas	Full RPS Class I	6,568	9,025	-100	197	419	0	1,121	499	2,351
Low Gas	Full RPS Class I	7,404	9,025	-100	199	419	0	990	635	1,783
Base Case	Low RPS Class I	7,081	9,025	-100	194	419	0	1,121	662	1,998
Tight Supply	Low RPS Class I	7,381	9,025	-100	194	419	0	990	521	1,688
Abundant Supply	Low RPS Class I	6,748	9,025	-100	194	419	0	1,504	534	1,819
High Gas	Low RPS Class I	6,560	9,025	-100	194	419	0	1,121	437	2,294
Low Gas	Low RPS Class I	7,394	9,025	-100	194	419	0	583	562	2,123
Base Case	New COS Gen, Hi MOP	7,064	9,025	-100	196	419	650	1,121	699	2,705
Tight Supply	New COS Gen, Hi MOP	7,360	9,025	-100	196	419	650	990	521	2,362
Abundant Supply	New COS Gen, Hi MOP	6,735	9,025	-100	196	419	650	1,504	587	2,539
High Gas	New COS Gen, Hi MOP	6,553	9,025	-100	196	419	650	1,121	530	3,046
Low Gas	New COS Gen, Hi MOP	7,378	9,025	-100	196	419	650	966	602	2,449
Base Case	New COS Gen, Lo MOP	7,061	9,025	-100	196	419	650	1,121	675	2,684
Tight Supply	New COS Gen, Lo MOP	7,360	9,025	-100	196	419	650	990	521	2,362
Abundant Supply	New COS Gen, Lo MOP	6,729	9,025	-100	196	419	650	1,952	537	2,047
High Gas	New COS Gen, Lo MOP	6,546	9,025	-100	196	419	650	1,568	460	2,536
Low Gas	New COS Gen, Lo MOP	7,378	9,025	-100	196	419	650	966	602	2,449

Figure 20
Connecticut Resource Adequacy Parameters in 2022, Differences Relative to Base Case

Future	Resource Scenario	CT TSA *(MW)*	Existing Gen *(MW)*	Existing Purchases and Sales *(MW)*	Renewable Additions *(MW)*	Energy Efficiency *(MW)*	New COS Gen *(MW)*	Retired Capacity *(MW)*	Active DR *(MW)*	Net Surplus (Shortage) *(MW)*
Base Case	Expanded EE	(88)	0	0	0	1,157	0	0	(130)	1,114
Tight Supply	Expanded EE	(71)	0	0	0	1,157	0	0	0	1,228
Abundant Supply	Expanded EE	(90)	0	0	0	1,157	0	448	(183)	615
High Gas	Expanded EE	(73)	0	0	0	1,157	0	778	(116)	336
Low Gas	Expanded EE	(68)	0	0	0	1,157	0	383	18	859
Base Case	Exp. EE & RPS Class I Flex.	(88)	0	0	0	1,157	0	0	(130)	1,114
Tight Supply	Exp. EE & RPS Class I Flex.	(71)	0	0	0	1,157	0	0	0	1,228
Abundant Supply	Exp. EE & RPS Class I Flex.	(90)	0	0	0	1,157	0	448	(183)	615
High Gas	Exp. EE & RPS Class I Flex.	(73)	0	0	0	1,157	0	778	(116)	336
Low Gas	Exp. EE & RPS Class I Flex.	(68)	0	0	0	1,157	0	383	18	859
Base Case	Full RPS Class I	(3)	0	0	1	0	0	0	(20)	(16)
Tight Supply	Full RPS Class I	(0)	0	0	3	0	0	0	0	3
Abundant Supply	Full RPS Class I	(3)	0	0	0	0	0	0	(18)	(15)
High Gas	Full RPS Class I	(4)	0	0	0	0	0	0	(30)	(26)
Low Gas	Full RPS Class I	5	0	0	2	0	0	0	33	31
Base Case	Low RPS Class I	(3)	0	0	(3)	0	0	0	(19)	(19)
Tight Supply	Low RPS Class I	0	0	0	(3)	0	0	0	0	(3)
Abundant Supply	Low RPS Class I	(8)	0	0	(3)	0	0	0	(53)	(49)
High Gas	Low RPS Class I	(12)	0	0	(3)	0	0	0	(93)	(83)
Low Gas	Low RPS Class I	(5)	0	0	(3)	0	0	(407)	(39)	371
Base Case	New COS Gen, Hi MOP	(19)	0	0	0	0	650	0	18	688
Tight Supply	New COS Gen, Hi MOP	(21)	0	0	0	0	650	0	0	671
Abundant Supply	New COS Gen, Hi MOP	(21)	0	0	0	0	650	0	0	671
High Gas	New COS Gen, Hi MOP	(19)	0	0	0	0	650	0	0	669
Low Gas	New COS Gen, Hi MOP	(22)	0	0	0	0	650	(24)	0	696
Base Case	New COS Gen, Lo MOP	(22)	0	0	0	0	650	0	(5)	667
Tight Supply	New COS Gen, Lo MOP	(21)	0	0	0	0	650	0	0	671
Abundant Supply	New COS Gen, Lo MOP	(27)	0	0	0	0	650	448	(50)	179
High Gas	New COS Gen, Lo MOP	(27)	0	0	0	0	650	448	(70)	159
Low Gas	New COS Gen, Lo MOP	(22)	0	0	0	0	650	(24)	0	696

Figure 21
ISO Resource Adequacy Parameters in 2022

Future	Resource Scenario	Net ICR *(MW)*	Existing Gen *(MW)*	Existing Purchases and Sales *(MW)*	Renewable Additions *(MW)*	Energy Efficiency *(MW)*	New COS Gen *(MW)*	Retired Capacity *(MW)*	Active DR *(MW)*	Generic Builds *(MW)*	Net Surplus (Shortage) *(MW)*
Base Case	Base	36,424	32,245	1,911	835	2,019	0	3,236	2,588	62	0
Tight Supply	Base	37,912	32,245	1,911	835	1,486	0	2,669	1,982	2,122	0
Abundant Supply	Base	34,979	32,245	1,911	835	2,019	0	4,251	2,233	0	13
High Gas	Base	34,607	32,245	1,911	835	2,019	0	4,354	2,013	0	62
Low Gas	Base	37,506	32,245	1,911	835	2,019	0	2,812	2,288	1,020	0
Base Case	Expanded EE	36,424	32,245	1,911	835	3,175	0	3,783	2,092	0	52
Tight Supply	Expanded EE	37,912	32,245	1,911	835	2,642	0	2,671	1,982	967	0
Abundant Supply	Expanded EE	34,979	32,245	1,911	835	3,175	0	4,725	1,537	0	0
High Gas	Expanded EE	34,607	32,245	1,911	835	3,175	0	5,132	1,572	0	0
Low Gas	Expanded EE	37,506	32,245	1,911	835	3,175	0	3,195	2,357	178	0
Base Case	Exp. EE & RPS Class I Flex.	36,424	32,245	1,911	835	3,175	0	3,783	2,092	0	52
Tight Supply	Exp. EE & RPS Class I Flex.	37,912	32,245	1,911	835	2,642	0	2,671	1,982	967	0
Abundant Supply	Exp. EE & RPS Class I Flex.	34,979	32,245	1,911	835	3,175	0	4,725	1,537	0	0
High Gas	Exp. EE & RPS Class I Flex.	34,607	32,245	1,911	835	3,175	0	5,132	1,572	0	0
Low Gas	Exp. EE & RPS Class I Flex.	37,506	32,245	1,911	835	3,175	0	3,195	2,357	178	0
Base Case	Full RPS Class I	36,424	32,245	1,911	1,023	2,019	0	3,236	2,511	0	49
Tight Supply	Full RPS Class I	37,912	32,245	1,911	1,183	1,486	0	2,669	1,982	1,774	0
Abundant Supply	Full RPS Class I	34,979	32,245	1,911	890	2,019	0	4,251	2,165	0	0
High Gas	Full RPS Class I	34,607	32,245	1,911	887	2,019	0	4,354	1,899	0	0
Low Gas	Full RPS Class I	37,506	32,245	1,911	1,114	2,019	0	2,812	2,415	614	0
Base Case	Low RPS Class I	36,424	32,245	1,911	553	2,019	0	2,801	2,518	0	21
Tight Supply	Low RPS Class I	37,912	32,245	1,911	553	1,486	0	2,669	1,982	2,404	0
Abundant Supply	Low RPS Class I	34,979	32,245	1,911	553	2,019	0	3,706	2,029	0	73
High Gas	Low RPS Class I	34,607	32,245	1,911	553	2,019	0	3,783	1,662	0	0
Low Gas	Low RPS Class I	37,506	32,245	1,911	553	2,019	0	2,405	2,138	1,044	0
Base Case	New COS Gen, Hi MOP	36,424	32,245	1,911	835	2,019	650	3,236	2,658	0	657
Tight Supply	New COS Gen, Hi MOP	37,912	32,245	1,911	835	1,486	650	2,669	1,982	1,472	0
Abundant Supply	New COS Gen, Hi MOP	34,979	32,245	1,911	835	2,019	650	4,251	2,233	0	663
High Gas	New COS Gen, Hi MOP	34,607	32,245	1,911	835	2,019	650	4,354	2,013	0	712
Low Gas	New COS Gen, Hi MOP	37,506	32,245	1,911	835	2,019	650	2,788	2,288	346	0
Base Case	New COS Gen, Lo MOP	36,424	32,245	1,911	835	2,019	650	3,783	2,568	0	21
Tight Supply	New COS Gen, Lo MOP	37,912	32,245	1,911	835	1,486	650	2,669	1,982	1,472	0
Abundant Supply	New COS Gen, Lo MOP	34,979	32,245	1,911	835	2,019	650	4,725	2,043	0	0
High Gas	New COS Gen, Lo MOP	34,607	32,245	1,911	835	2,019	650	4,802	1,749	0	0
Low Gas	New COS Gen, Lo MOP	37,506	32,245	1,911	835	2,019	650	2,788	2,288	346	0

Figure 22
ISO Resource Adequacy Parameters in 2022, Differences Relative to Base Case

Future	Resource Scenario	Net ICR (MW)	Existing Gen (MW)	Existing Purchases and Sales (MW)	Renewable Additions (MW)	Energy Efficiency (MW)	New COS Gen (MW)	Retired Capacity (MW)	Active DR (MW)	Generic Builds (MW)	Net Surplus (Shortage) (MW)
Base Case	Expanded EE	0	0	0	0	1,157	0	547	(496)	(62)	52
Tight Supply	Expanded EE	0	0	0	0	1,157	0	2	0	(1,155)	0
Abundant Supply	Expanded EE	0	0	0	0	1,157	0	474	(696)	0	(13)
High Gas	Expanded EE	0	0	0	0	1,157	0	778	(441)	0	(62)
Low Gas	Expanded EE	0	0	0	0	1,157	0	383	69	(842)	0
Base Case	Exp. EE & RPS Class I Flex.	0	0	0	0	1,157	0	547	(496)	(62)	52
Tight Supply	Exp. EE & RPS Class I Flex.	0	0	0	0	1,157	0	2	0	(1,155)	0
Abundant Supply	Exp. EE & RPS Class I Flex.	0	0	0	0	1,157	0	474	(696)	0	(13)
High Gas	Exp. EE & RPS Class I Flex.	0	0	0	0	1,157	0	778	(441)	0	(62)
Low Gas	Exp. EE & RPS Class I Flex.	0	0	0	0	1,157	0	383	69	(842)	0
Base Case	Full RPS Class I	0	0	0	188	0	0	0	(77)	(62)	49
Tight Supply	Full RPS Class I	0	0	0	348	0	0	0	0	(348)	0
Abundant Supply	Full RPS Class I	0	0	0	55	0	0	0	(68)	0	(13)
High Gas	Full RPS Class I	0	0	0	52	0	0	0	(115)	0	(62)
Low Gas	Full RPS Class I	0	0	0	279	0	0	0	127	(406)	0
Base Case	Low RPS Class I	0	0	0	(282)	0	0	(435)	(70)	(62)	21
Tight Supply	Low RPS Class I	0	0	0	(282)	0	0	0	0	282	0
Abundant Supply	Low RPS Class I	0	0	0	(282)	0	0	(545)	(203)	0	60
High Gas	Low RPS Class I	0	0	0	(282)	0	0	(571)	(352)	0	(62)
Low Gas	Low RPS Class I	0	0	0	(282)	0	0	(407)	(150)	24	0
Base Case	New COS Gen, Hi MOP	0	0	0	0	0	650	0	69	(62)	658
Tight Supply	New COS Gen, Hi MOP	0	0	0	0	0	650	0	0	(650)	0
Abundant Supply	New COS Gen, Hi MOP	0	0	0	0	0	650	0	0	0	650
High Gas	New COS Gen, Hi MOP	0	0	0	0	0	650	0	0	0	650
Low Gas	New COS Gen, Hi MOP	0	0	0	0	0	650	(24)	0	(674)	0
Base Case	New COS Gen, Lo MOP	0	0	0	0	0	650	547	(20)	(62)	21
Tight Supply	New COS Gen, Lo MOP	0	0	0	0	0	650	0	0	(650)	0
Abundant Supply	New COS Gen, Lo MOP	0	0	0	0	0	650	474	(189)	0	(13)
High Gas	New COS Gen, Lo MOP	0	0	0	0	0	650	448	(265)	0	(62)
Low Gas	New COS Gen, Lo MOP	0	0	0	0	0	650	(24)	0	(674)	0

RELIABILITY IMPLICATIONS OF RELIANCE ON NATURAL GAS

Another dimension of resource adequacy that does not correspond to any current ISO-NE requirement is preparedness for severe winter cold snaps, when there may be limited natural gas pipeline capacity available on a non-firm basis. Much gas-fired generation lacks firm gas delivery, relying on interruptible capacity instead. Particularly with the likely retirement of a significant amount of non-gas capacity, there are concerns that the system would need to rely to an even greater extent on gas-fired generation without firm fuel supplies, and potential problems with gas deliverability might threaten electric reliability. New England's gas supply infrastructure is used both to provide gas to electric generators, and to supply natural gas directly to the core residential and commercial customers of the gas local distribution companies (LDCs). In colder winter weather, the demand for gas to serve core customers' heating requirements can stress the capabilities of the gas delivery system, complicating the ability of electric generators that rely on as-available interruptible pipeline transportation capacity to have gas delivered to their power plants.[31]

Difficulties such as this have occurred in the past, for example in the extreme cold snap in January 2004, when a significant amount of gas-fired capacity was unavailable to generate power because it had difficulty getting gas delivered (due in part to the lack of coordinated operational timing between the gas transportation and the electric systems, and the limitations of the gas infrastructure). In principle, if enough gas-fired capacity had difficulty with fuel deliverability, and that capacity was needed to serve load, this could pose a threat to overall power system reliability.[32]

The impact of the gas delivery system on electric system reliability has two primary components:

1. Whether fuel availability to some gas-fired generators is constrained, and

2. The extent to which the system needs to rely on these gas-fired generators to meet load.

Only if gas deliverability to some gas-fired generators is constrained, *and* the system needs these gas generators to meet load, will this potential concern translate into a reliability problem. This question becomes relevant only when the system faces extreme conditions, since under most circumstances, there is adequate ability to supply gas to electric generation, and the power system does not typically need all its available generating capacity to serve load. The demand for electricity peaks in summer, and the natural gas system peaks in winter. In practice, during summer peak times when the power system relies on essentially all its available generation to ensure reliability, the gas delivery system is typically unconstrained, so the summer resource

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[31] See discussion on firm and interruptible transportation service in Appendix F (Natural Gas).

[32] The ISO New England currently has a study underway — an Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Power Generation Needs — to address issues regarding the dependence of the New England electric system on natural gas. The study is intended to "assess the total amount of natural gas pipeline transportation capacity available to serve the regional gas-fired power generation sector," from the present through 2020. It was originally scheduled for release in September 2011, but was delayed. Shortly before publication of this document, the ISO released a presentation based on a draft of its report.

adequacy picture is not affected by gas deliverability issues.[33] Because the demand for gas for heating in cold winter weather stresses the gas delivery system, it is the winter season that presents the most likely potential for difficulties in supplying fuel to gas generators. Winter electric conditions are less extreme than summer: the power system has lower overall electric load, higher thermal generating capacities and more generation from wind, and all of these factors help to mitigate any reliability impacts of potential winter gas deliverability problems. But whether winter gas deliverability ultimately may pose a threat to reliability is a question of how these factors balance.

Gas Deliverability Issues for Gas-Fired Generators

Regarding the question of whether gas-fired electric generators may face fuel deliverability problems, generators face several different types of circumstances. A significant share of New England's gas-fired generation, roughly 5,300 MW, has dual fuel capability (typically oil backup), and so in reliability terms, gas deliverability to these generators is not an issue, assuming they have sufficient fuel oil inventory and/or can replenish it adequately. Some of the remaining gas-only generating capacity has firm pipeline transportation capacity. Following the 2004 cold snap, the ISO reported that 5,899 MW of generating capacity had firm gas transportation capacity; according to available information from the pipelines' index of customers, the current amount of capacity supported by firm mainline gas transportation may be closer to 1,650 MW, of which about 500 MW is in Connecticut. The gas pipeline system is designed to be able to serve all its firm transportation customers' needs even under extreme conditions — this is of course what it means to have firm pipeline transportation — so gas capacity backed by firm pipeline transportation should not be limited by fuel deliverability problems either. In addition, the Mystic gas units 8 and 9 (840 MW each) are directly connected to the Everett LNG terminal, which should allow these units to operate even when gas deliverability on the interstate pipeline system is limited.[34] This is a total of about 3,300 MW of gas-fired capacity that currently has firm gas supply, either through firm pipeline transportation contracts or firm LNG supply, for a total of over 8,500 MW with reliable fuel supplies, either dual fuel or firm gas supply.

The remaining gas-fired capacity, about 7,000 MW of gas-only plants without access to firm gas supplies, must rely on non-firm or interruptible gas pipeline transportation. This has been an area of concern for the New England electric system — that in extreme conditions, gas-only generators that have not arranged for firm gas transportation may be unable to obtain fuel, and that their resulting inability to generate might threaten electric system reliability. The discussion in Appendix F (Natural Gas) shows that in fact, in Connecticut and across New England, it is not uncommon for interruptible gas transportation customers to have their gas nominations cut in the winter.

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[33] The ISO determines generating capacity requirements based on summer peak conditions, and so naturally the system needs its full capacity requirement under summer peak conditions. When there is a capacity surplus, as now, there will be some excess generating capacity even at system peak conditions.

[34] In 2000, the owner of the Mystic units signed a 20-year contract for firm gas supplies from the Everett LNG terminal, to begin in 2002 when the Mystic generating station became operational.

It has been the case that even in past stress events like the January 2004 cold snap, some of the generators that lacked firm gas transportation were able to obtain gas and did operate, and the ISO's current operational planning assumes that only about 3,800 MW might be at risk due to gas supply.[35] There are a couple of reasons why even gas units without firm transportation may be able to obtain gas supplies. They may be able to obtain gas using interruptible transportation capacity, which is offered by the pipelines to the extent capacity is unutilized by firm customers. As LDC demand increases in cold weather periods, the amount of available interruptible capacity is diminished. Even in these circumstances, a generator may be able to purchase delivered gas supplies from a pipeline shipper (potentially a marketer, industrial end-user, or even an LDC), if there is one who does not currently need to use their firm transportation capacity. In New England, this may be in the form of LNG that is injected downstream and transported via backhaul.[36]

Generators have direct incentives to maintain their availability as well. They are paid for energy only when they actually generate, and energy prices can be particularly attractive in system stress conditions. Perhaps more importantly, during shortage conditions generators can face penalties up to 5% of their annual capacity revenue for being unavailable, for whatever reason, during a single shortage event of five or less hours. For repeated or extended outages they can potentially lose 100% of their capacity revenues. This gives them direct financial incentives to ensure that they have access to fuel when the power system needs their capacity. A precise determination of how much gas can be delivered to gas plants that lack firm transportation would necessitate detailed gas system modeling, and the result would likely be highly dependent on the particular details of the situation, which may be difficult to predict in advance.

The gas system is designed and operated to provide reliable gas transportation to its firm customers, while interruptible customers are served only on an "as-available" basis. Gas generators who lack firm gas transportation have no reliable claim on the capability of the gas delivery system, and thus may not always be able to count on obtaining gas, particularly in extreme winter conditions when the gas system can be pushed to its limits. A related issue is that gas generators in New England are likely to have less flexibility going forward than they have had in the past with respect to short-term variations in their gas usage. Historically, the generators had some flexibility relative to the amount of gas they scheduled on the pipelines (meaning that burns could diverge from scheduled quantities and the generators could be out of balance). However, pipelines have been tightening their balancing rules, partly in response to operational difficulties that have arisen as generators have taken gas in excess of their scheduled quantities. These rules serve to limit the ability of generators to take gas in excess of their scheduled quantities — *e.g.*, by imposing penalties for exceeding scheduled quantities, or by

[35] Final Report on Electricity Supply Conditions in New England During the January 14 - 16, 2004 "Cold Snap," ISO New England Inc. Market Monitoring Department, October 12, 2004.

[36] For example, LNG supplies received in eastern Canada at the Canaport LNG terminal are transported to New England via the Maritimes & Northeast pipeline, which terminates in Massachusetts at interconnects with Tennessee Gas Pipeline and Algonquin Gas Transmission. Thus, supplies from Maritimes & Northeast can be received into Tennessee and Algonquin and transported on a backhaul basis, although the availability of such supplies depends on both the availability of sufficient quantities of LNG at the terminal, and the availability of backhaul capacity on the relevant pipeline(s).

physically restricting gas flows — and may impact the ability of generators to swing up and down on short notice.

Further analysis of the gas system would be required to fully understand the amount of gas-fired capacity that lacks firm fuel supplies ("non-firm gas capacity") that may be reliably available in extreme circumstances, recognizing explicitly the potential for limited gas availability that may simultaneously affect a significant amount of gas-fired capacity. It may require developing probability distributions for non-firm gas capacity availability as a function of LNG import availability and specific constraints, temperature, load, location, *etc.* But even absent this type of analysis, it is helpful to look also at the other half of the equation — the extent to which the power system needs to rely on gas-fired generation.

Electric System Reliance on Natural Gas in Winter Periods

The second piece of this question regards the extent to which the power system needs to rely on gas-fired generation under the winter conditions that might lead to gas deliverability problems. The electric system's generating capacity is sized to meet summer peak load, and for several reasons this creates some slack generating capacity in the winter. Winter peak loads are substantially lower than summer peak, by about 20%, or 6,300 MW, and the generating capacities of thermal generators are higher, which adds about 8%, or 2,200 MW, to total generating capacity.[37] A smaller factor is the higher production by wind turbines, which generate more energy and thus provide a greater amount of reliable capacity in winter than in summer. These factors mean that unlike in summer when the electric system may need all the capacity it has, under winter conditions it could operate reliably even if significant amounts of capacity were unavailable. To understand whether this slack may be large enough to counterbalance concerns about winter gas availability, a comparison of winter loads and resources is instructive.

Figure 23 illustrates winter system generating capacity and winter loads on this basis. Consistent with this IRP's Base Case projection (and with the ISO-NE CELT report), it reflects lower winter loads and the higher winter capacities of thermal generators, as well as expected retirements and generation additions for 3, 5 and 10-year time horizons (it does not, however, reflect the greater availability of wind resources in winter).[38] To facilitate understanding the extent to which the system relies on gas, Figure 23 distinguishes types of generating capacity, though it is important to recognize that this is *not* an economic dispatch ordering and thus does not approximate how the system is actually operated. Gas-fired capacity is shown near the top of the bar. Some of this gas-fired capacity has dual fuel capability, firm pipeline transportation or firm LNG access, and some has none of these and must rely on access to non-firm gas supplies.

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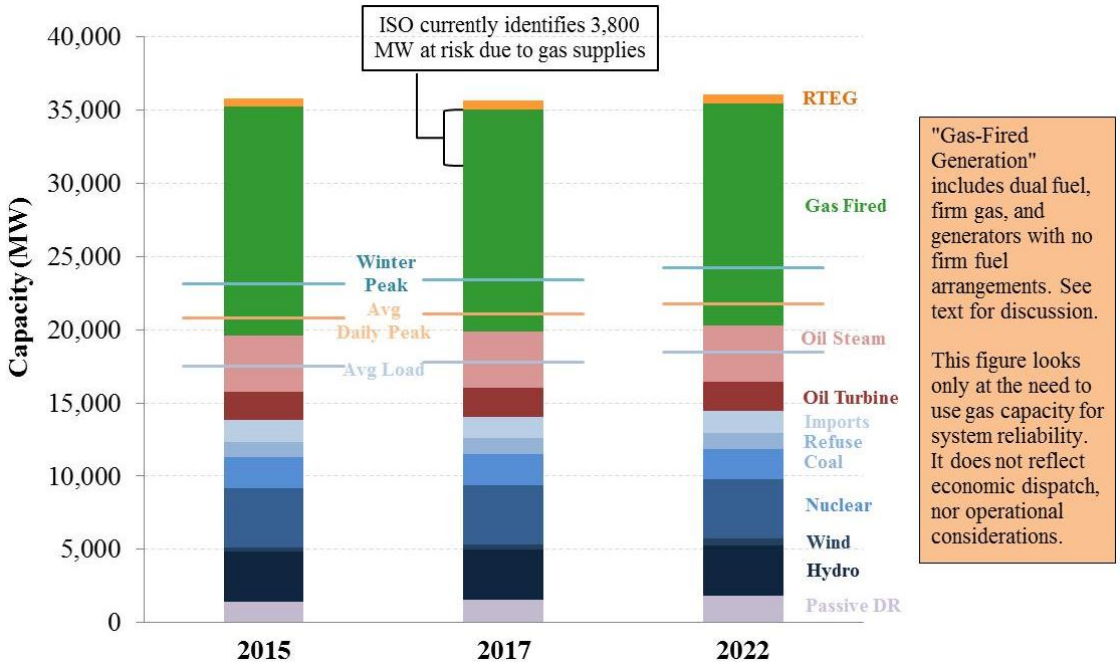
[37] Using projected peak-load and generation capacities for winter of 2015.

[38] Figure 23 conservatively excludes all Active Demand Response resources, since some of the Active DR that clears in the Forward Capacity Market consists of interruptible summer loads that are not available in winter. New England's Forward Capacity Market rules require that Active DR be available in winter as well as summer, so some of these interruptible summer loads pair with the incremental winter capacity of thermal generators. By excluding all Active DR from the winter capacity calculation, any possible double-counting of this capacity is avoided.

Figure 23
Winter Generating Capacity vs. Winter Demand in ISO-NE



Sources: Capacities are from CELT, net of Base Case retirements, and excludes Active DR. Loads are based CELT demand forecasts.

Comparing loads to supply, it is clear that at all three of these time points, there is a need to rely on gas-fired capacity in the winter, particularly to meet daily and seasonal peaks. Furthermore, the actual capacity needed to operate the system reliably is much higher than the peak load shown above, to allow a reserve margin for outages, operating reserves, *etc.* This means that a significant share of the 15,600 MW of total gas-fired capacity will be needed to meet reliability requirements. By 2022, with growing load and allowing for a reserve margin, this could approach roughly half the total gas-fired capacity, in addition to all the non-gas capacity.

Figure 24 shows that currently over 8,500 MW of gas-fired generation appears to have reliable fuel arrangements (*i.e.*, dual fuel capability, firm pipeline supply, or LNG). This, in combination with non-gas capacity, may be enough to satisfy the system's winter capacity requirements.[39] For another perspective on this, the ISO's current operational planning assumes 3,800 MW of generation may be at risk due to gas supplies under extreme load conditions. Unless the total

[39] To further test the extent to which the system actually needs to rely on gas to meet load, we simulated electric system operation in the winter season for each study year under modified Base Case assumptions. Dual fuel units were operated entirely on their alternative (oil) fuel, and gas was made the fuel of last resort (the stress test was particularly stringent since it assumed all gas-fired units, including those currently with firm pipeline capacity or dual-fuel capability, were unable to get gas). These simulations showed that it would be theoretically possible in all but a few hours to meet winter electric loads with little or no reliance on natural gas, if all dual fuel generation could operate fully on its alternate fuel. For just a few extreme hours, the system is at the limit of its ability to operate without gas, and would need to either dispatch a few hundred MW of gas capacity, or begin to reduce its operating reserves.

gas-fired capacity at fuel supply risk is much larger than this amount, this similarly suggests that there may be adequate infrastructure resources in place, given that the overall winter capacity balance has substantial slack relative to summer.

Figure 24
Gas-Fired Generating Capacity — Fuel Supply Reliability
(Winter MW, Base Case)

Type	2015 *(MW)*	2017 *(MW)*	2022 *(MW)*
Dual Fuel	5,283	4,838	4,838
Firm Pipeline Supply	1,619	1,619	1,619
Mystic (LNG)	1,679	1,679	1,679
Non-Firm Gas Only	7,008	7,017	7,079
Total Gas-Fired Capacity	15,590	15,154	15,216

Note: Wallingford/Pierce has both firm pipeline capacity for roughly 35 MW and dual fuel capability. It has been listed under Dual Fuel.

However, the generators that do have dual fuel capability and firm gas arrangements are not required by the ISO to have these capabilities, and there is currently no system in place to qualify these resources or verify that they continue to maintain these capabilities.[40] There are no direct incentives for maintaining these capabilities, or penalties for failing to maintain them (though of course there are the normal incentives through the energy and capacity markets for generators to maintain their availability). There are several factors related to this that could affect electric system reliability, either positively or negatively, including the following:

- Units with dual fuel capability may or may not be able to run at full capacity on their alternate fuel, for as long as necessary. To do so requires that dual fuel units have sufficient backup fuel inventory onsite, and/or be able to replenish it. There may also be operational limits on generators' ability to switch from gas to oil on short notice. If dual-fuel units have operational limits on their ability to rely on their alternate fuel, their contribution to system reliability may be smaller than the total 5,300 MW of dual-fueled capacity shown in Figure 24.
- Gas units that currently have either dual fuel or firm gas capability may or may not continue to maintain that capability in the future, absent requirements or incentives. If some of these units allow their capabilities to lapse, their

[40] Although the ISO does not require dual fuel capability, the Connecticut Siting Council has required it for some Connecticut gas-fired generators as a condition of siting. However, in the past year, the Siting Council has granted requests from three plants to relieve them of this obligation, and it notes that it might receive and grant similar requests from other generators in the future. Furthermore, the situation is more complex than the mere presence or absence of dual fuel capability. A "dual fuel" unit that maintains an inventory of fuel oil onsite and is able to switch in a matter of hours would provide useful protection against a gas supply disruption that occurs with little advance notice. But some "dual fuel" units may not be able to respond so quickly. For example, the ISO-NE CELT report identifies Lake Road Unit 1 as a dual fuel unit, but it operates solely on natural gas and would need up to 15 days to recommission on fuel oil – too slow to respond to a short-notice gas supply disruption.

contribution to system reliability may be smaller than the current amounts reflected in Figure 24.

- Pipelines are tightening restrictions on flexibility to protect system integrity in light of higher gas demands, which may affect generators' gas usage. Reduced flexibility might limit generators' availability.
- Availability of interruptible and secondary gas transportation is declining due to regional demand growth from LDCs and generators.
- Outages or operational limits on using non-gas units may also affect the extent to which the system needs to rely on gas-fired capacity. Generators that run only rarely may have operational difficulties when they are called upon, or operational constraints — such as slow start, ramping limits, and long minimum up and down times — may make it more difficult to utilize some non-gas generation.
- Retirements of non-gas capacity can also affect the need to rely on gas-fired capacity. If retirements of non-gas capacity are significantly higher than in the Base Case, the system would need to rely to a greater extent on gas-fired generation.

The analyses described above consider only the generation infrastructure and whether there may be enough installed capacity relative to peak requirements, considering possible gas system constraints. They do not fully reflect how the electric system operates; actual operation is much more complex, and the electric system does in fact routinely utilize gas-fired generation to meet winter electricity needs, including during times when the gas delivery system is stressed. In fact, gas is used in large quantities, since it is more economic than many other generation sources; gas units are generally dispatched before oil units, and in some cases before coal capacity. This means that gas utilization can create operational challenges that become particularly acute when the gas system is stressed in severe cold weather, even if the system has enough overall non-gas, dual fuel and firm gas capacity to meet its capacity needs. See Appendix F (Natural Gas) for a discussion of some of these operational issues.

The ISO has taken some steps to address the issue of gas reliance, and is now further investigating and acting on this. In response to the January 2004 cold snap, the ISO made changes to improve operational performance and coordination with gas pipelines. The Electric Gas Operations Committee ("EGOC") was formed in the summer of 2004, consisting of participants from the ISO as well as representatives from the natural gas pipelines, LDCs, and LNG terminals serving New England to "increase education, understanding, communication and coordination between the regional gas and electric industries."[41]

In 2005, the ISO also established detailed operating procedures to follow during cold weather conditions. The Cold Weather Event Operations procedures (ISO New England Market Rule 1, Appendix H) instruct the ISO to include several factors that might affect generation resource availability (such as pipeline operating conditions, fuel supply, dual-fuel switching capabilities) as part of its 7-day forecast. The ISO must post warnings of cold weather events several days in advance, and generators are required to communicate changes to their availability (including

[41] Final Minutes, Electric/Gas Operation Committee, Meeting No. 1, July 13, 2004.

ability to procure fuel, physical generating limitations, and dual-fuel switching) to the ISO. The market rule also allows for the ISO to request gas-fired generators with dual-fuel capability to voluntarily switch to their alternative fuel once a cold weather event is in effect, with 2 days advance notice. In a cold weather event, the ISO has the ability to change the day-ahead energy market trading deadline from 12:00 PM to 9:00 AM to better match the natural gas scheduling and nomination cycles and facilitate greater utilization of the gas infrastructure by gas-fired generators.[42] The ISO also removes the $1,000/MWh "Effective Offer Price Cap" during emergencies, to allow generators to recover costs when fuel prices may be unusually high.[43]

The ISO's current Strategic Planning Initiative has identified and is addressing gas system dependency as a key strategic risk that is likely to increase as older non-gas units retire. The ISO has a study currently underway to evaluate the natural gas infrastructure and its ability to serve the needs of electric generation in the region. Shortly before publication of this document, the ISO released a presentation based on a draft of its report.[44] That presentation suggested that regional gas supply capability is inadequate to satisfy regional gas demands on a winter design day over the next decade. However, the study did not explicitly consider electric system reliability and for instance did not consider that a substantial amount of gas-fired capacity has dual-fuel capability and can operate on its alternate fuel if necessary to preserve reliability. The ISO is also considering establishing portfolio standards or requirements related to fuel certainty, such as by creating obligations and/or incentives for generators to ensure their availability, or by increasing the consequences of poor performance under stressed system conditions.

The New England electric system relies on significant amounts of gas-fired capacity to meet winter loads. A substantial amount of this gas-fired capacity currently has dual fuel capability, firm pipeline transportation, or firm LNG supplies. However, there is no requirement for generators to maintain reliable access to fuel, and thus the firmness of these fuel supplies may not be verified or regularly tested. Beyond this, the fact that natural gas is a "just-in-time" fuel delivery system can raise a number of operational challenges for both the electric and gas systems, as noted above and discussed in greater detail in Appendix F (Natural Gas). For the longer term, the issue of gas reliance in winter warrants continued close attention, since a number of uncertain factors influence the degree to which the electric system depends on gas-fired capacity that may lack firm fuel supplies or dual fuel capability. These factors include retirements of non-gas capacity, the extent to which gas units with firm fuel or dual fuel capability maintain that capability, and the extent to which the electric system can rely on gas-fired generators without firm fuel supplies. This is a complex issue that requires further analysis, potentially including modeling of cross-system dependencies between the electricity and gas systems to fully understand their interactions under stress conditions. The ISO is currently investigating this issue through its strategic planning process and may make changes to its rules and operations, potentially modifying the FCM to account for winter gas availability. Connecticut should participate in this process.

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42 Section III, Market Rule 1, Appendix H: Operations During Cold Weather, ISO-NE.

43 117 FERC ¶61,082, p.6.

44 "Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Power Generation Needs," presented by ICF International to ISO-NE Planning Advisory Committee, December 14, 2011.

APPENDIX C

ENERGY EFFICIENCY

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INTRODUCTION

This appendix provides background on the existing energy efficiency activities in Connecticut and includes a description of this IRP's Base Case Energy Efficiency ("Base Case EE") and Expanded Energy Efficiency ("Expanded EE") scenarios. Alternative policy approaches to achieving the savings identified in the Expanded EE scenario are also discussed.

BACKGROUND

Connecticut has a successful history of implementing energy efficiency. In 2007, Public Act 07-242, *An Act Concerning Electricity and Energy*, portrayed energy efficiency as the centerpiece of a statewide energy policy and directed the State to implement "all-cost effective energy efficiency." More recently, Connecticut's landmark energy reform bill, Public Act No. (PA) 11-80, made significant changes to Connecticut's energy conservation policy and structure, representing a fundamentally new approach to achieving energy efficiency. PA 11-80 allows Connecticut to align its energy efficiency goals with national goals and objectives and to work toward positioning Connecticut as a leader in the nation for energy efficiency. Specifically, the Act calls for aggressive efficiency targets for weatherization of residential buildings and state-owned or –leased buildings, and addresses the leveraging of existing funds to provide low-cost energy efficiency financing and the utilization of savings-based and performance-contracting initiatives. Part of the implementation of PA 11-80 will involve the Electric Distribution Companies' (EDCs) continued annual submission of a Conservation and Load Management (C&LM) Plan to DEEP and PURA, in accordance with Connecticut General Statutes §16-245m and §16-32f. This plan is developed with the advice and assistance of the Energy Efficiency Board (EEB) and its consultants. In addition to planning energy efficiency programs for a one-year budget cycle, the 2012 C&LM plan also reports that in 2010, the EDCs delivered average energy efficiency (EE) savings of approximately 50 MW in peak load reduction and 400 GWh of energy per year.

BASE CASE EE SCENARIO

Description of Base Case Programs

The Base Case Energy Efficiency (Base Case EE) scenario for Connecticut reflects "business-as-usual" EE, with continuation of the EDCs' program structures and designs currently deployed in Connecticut within state approved program budgets. Base Case EE represents what is achievable through the existing funding structures:

- 0.3 ¢/kWh charge on customer bills provided for in the CT General Statute §16-245m;
- Revenues received from ISO-NE for EE capacity entered into ISO-NE's Forward Capacity Market;
- Revenues resulting from the sale of Class III Renewable Energy Credits (RECs) provided for under Docket No. 05-07-19RE01 and PA 07-242; and
- Revenues from the Regional Greenhouse Gas Initiative (RGGI).

The Base Case EE plans primarily include continuation and extension of the EDCs' current programs. The Base funding is estimated at approximately $101 million in the EDCs 2012 C&LM plans. The EDCs' 2012 C&LM plans include the following residential programs:[1]

1. *Home Energy Solutions (HES)*: The HES Program began in 2006 as a residential duct sealing pilot. Since that time, it has grown to a multi-million dollar retrofit program with 26 vendors delivering "core services" to customers throughout Connecticut. In 2011, the limited income program (HES Income Eligible, or HES-IE) was merged under the existing HES umbrella, allowing the Electric Distribution Companies to market a single program to all eligible customers. In the HES program, an authorized contractor performs an energy assessment, makes on-the-spot improvements, and depending on the customer's eligibility, provides exclusive money saving rebates on appliances, HVAC (heating, ventilation, and air conditioning) systems and insulation. A fee is collected from the customer at the time of the service for the non-limited income portion of HES.

2. *Retail Product Programs*: This program consists mainly of offering customers discounted compact fluorescent light bulbs (CFL). Although many residential customers are transitioning to the CFLs naturally over time, a 2009 survey administered by the Energy Efficiency Fund revealed that the CFL saturation was only 23% in Connecticut. The Energy Independence and Security Act ("EISA") of 2007 may phase out certain standard-use incandescent bulbs beginning in 2012, but it is not expected that CFLs will replace all traditional incandescent bulbs. Some manufacturers have already produced EISA-compliant halogen products, which are more efficient than incandescent bulbs but are substantially less efficient than CFLs. For that reason, the EDCs will continue CFL programs beyond the EISA deadline. In 2011, the EDCs began to offer upstream incentives for light-emitting diodes (LEDs) for a small number of retailers. In 2012, the EDCs plan to increase the number of LEDs under negotiated cooperative promotions to educate customers on the benefits and availability of LEDs at numerous retailer outlets across the State.

3. *Residential New Construction Program*: This program will phase in new ENERGY STAR version 3.0 requirements. The new requirements include additional thermal enclosure systems, thermal bridging criteria and water management systems, and HVAC design and testing requirements. The CT Zero Energy Initiative will continue and become an integral part of the program through the addition of a new incentive track called "Low Load Homes."

The EDCs' 2012 C&LM plans include the following commercial and industrial (C&I) programs:[2]

1. *Energy Conscious Blueprint/Lost Opportunity Program*: This program serves the new construction and equipment-replacement markets. The term "lost opportunity" refers to

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[1] 2012 C&LM Plan (link below):

http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/2fa1f8d01cfc0cc785257981007276d4/$FILE/2012%20CLM%20Electric%20and%20Gas%20Plan%20FINAL.pdf

[2] *Ibid.*

the situation where energy savings opportunities beyond those implied by the existing codes and standards would be lost without intervention. To address this sub-optimal level of energy efficiency enhancements, the Energy Conscious Blueprint offers comprehensive programs for new construction.

2. *Energy Opportunities Program*: This program is based on implementing a comprehensive initiative that encourages program participants and contractors to look beyond the "low-hanging fruit" to achieve deeper savings in existing commercial, industrial, and municipal facilities. The program offers incentives, financing, and other resources to replace existing, inefficient equipment with energy-saving options. They are mainly focused on higher performance lighting technologies and targeted efforts to eliminate older fluorescent lighting technologies from customer facilities.

3. *Small Business Energy Advantage (SBEA) Program*: This program provides cost-effective, turnkey energy efficiency services for small business customers. These services typically include energy assessments and installation of measures, and are provided by a network of approved contractors. The Electric Distribution Companies pay incentives for relevant energy efficiency measures within cost-effectiveness constraints and offer an interest-free financing option to credit-qualifying customers for the balance. The financed contract amount appears as a line item on the customer's electric bill.

4. *Business and Sustainability Challenge*: This program is designed to capture energy savings through information-based behavioral change and capital investments by customers. It will use various forms of energy use feedback mechanisms such as energy dashboard tools to show the end-user how much energy they have used compared to another point in time. With this knowledge, customers are expected to make more informed decisions on how to maintain equipment and system performance on an ongoing basis.

Base Case Savings and Budgets

The Base Case EE programs are expected to yield roughly 200 GWh of annual savings per year (0.6% of the gross CT load in 2012) in the 2012 and 2022 time frames. As a result of continuous implementation of the Base Case EE programs over the study period, the cumulative annual energy savings (starting in 2012) are expected to reach 2,277 GWh in 2022. These energy efficiency programs are also expected to yield approximately 30 MW of annual capacity savings, with cumulative annual capacity savings reaching 309 MW in 2022. These cumulative annual savings result from adding new measures to the program mix every year. It is estimated that the annual program cost of implementing the Base Case EE programs is approximately $101 million per year. Figure 1 presents the Base Case EE Program savings and budget.

Figure 1

Summary of Base Case EE Program Savings and Costs

		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
New Energy Savings	*(GWh)*	235	224	218	213	209	205	201	195	194	192	190
Cumulative Annual Energy Savings	*(GWh)*	235	459	678	891	1,101	1,305	1,506	1,701	1,895	2,087	2,277
New Capacity Savings	*(MW)*	30	29	29	29	28	28	28	27	27	27	27
Cumulative Annual Capacity Savings	*(MW)*	30	60	89	117	145	173	201	228	255	282	309
Annual Budget	*($Mil)*	101	99	99	99	99	99	99	100	100	100	100

This IRP does not quantify the benefits of the Base Case EE scenario. It only quantifies the incremental costs and benefits of the Expanded EE scenario relative to the Base Case.

Relationship to ISO New England's Load Forecasts

We reviewed how ISO New England's 2011 peak and energy forecast methodology accounts for past and future impacts of EE programs. As a result of our methodology review, we decided to use the ISO's energy and peak forecasts *net of passive demand resources cleared through* the forward capacity auction for the 2014/15 delivery year (FCA5) without additional adjustments for potential future energy efficiency. The details of our methodology review are discussed in Appendix B (Resource Adequacy).

This approach recognizes that ISO's "gross" forecast already partially accounts for the effects of future energy efficiency on the future load growth rate. As explained in Appendix B (Resource Adequacy), the load forecast is based on regression analysis, with much of the historical regression data reflecting metered loads net of energy efficiency. Thus, to the extent that historical efficiency programs tempered historical growth rates, these tempered growth rates are partially projected forward, implicitly assuming similar programs will continue to improve the energy efficiency of the economy. Deducting *all* future energy efficiency would partially double-count the effects of energy efficiency and thus understate future metered load. This IRP therefore does not count all future energy efficiency against ISO-NE's load forecast. Whereas we fully deduct energy efficiency cleared through 2014/15 and beyond, we do not further increase the deduction for additional energy efficiency that might be implemented after 2014/15. This approach is reasonable given the incomplete data on how historical energy efficiency tempered electricity growth rates (and hence the forward-looking rate that is essentially extrapolated from the past) and incomplete data on future energy efficiency throughout New England. This approach would likely achieve approximately the right effect of energy efficiency in the long-run, and any errors are likely to be within the larger errors inherent in load forecasting during these economically uncertain times.

Recognizing the uncertainties in future load levels, this IRP includes an analysis of alternative futures in which, among other factors, the load is higher (in the "Tight Supply" future) or lower (in the "Abundant Supply" future). In addition, even if there were a slight bias in the load forecast, it would not substantially affect the evaluation and benefits of the Expanded EE Resource scenario within each Future. The Expanded EE Scenario is defined precisely relative to the Base Case, such that each incremental unit of program savings beyond the EE Base Case reduces the load forecast by one unit.

EXPANDED EE RESOURCE SCENARIO

The Expanded EE scenario is based on the 2010 *Potential Study* sponsored by the Connecticut Energy Efficiency Board (EEB) and conducted by KEMA Consulting, with input from the EEB members and the Electric Distribution Companies. The *Potential Study* estimates the cumulative annual savings that could be achieved after ten years of implementation, as compared to a baseline in which customers will install only measures with minimum energy efficiency ratings.

The *Potential Study* employs a bottom-up approach in which hundreds of measures from different sectors are evaluated for their energy efficiency savings potential. A full list of the energy efficiency measures and programs and their contributions to the Program Achievable Potential savings, and hence to this IRP's Expanded EE scenario savings, can be found in the *Potential Study* Appendices.

The study starts with developing a *technical potential* based on a detailed bottom-up analysis of hundreds of individual measures in each sector. The technical potential represents the savings that would result if all customers adopted the most efficient measures regardless of their cost. After the technical potential is calculated, the study calculates an *Initial Economic Potential* that includes only those measures with lifetime benefits exceeding costs. Each measure's cost includes not only the incremental cost of equipment, but also the installation cost, except for retrofits that would have similarly occurred in the baseline (but with less efficient equipment). Benefits are based on the "Avoided Cost Study" by Synapse in 2007. Avoided costs include avoided energy and capacity costs, avoided transmission and distribution costs, energy and capacity DRIPE (demand response induced price effect), renewable energy credits (RECs) and avoided environmental externalities.[3]

The Initial Economic Potential is then adjusted upward by 10% to reflect the impact of emerging technologies and cost reductions over the study period, yielding a *Total Economic Potential*. Next, the *Total Achievable Potential* is calculated by reducing the Total Economic Potential by 15% to account for barriers to customer adoption. It is important to note that these four potential measures include energy savings from all sources including the EDC programs, building codes, standards (the light bulb standard), and naturally occurring savings.

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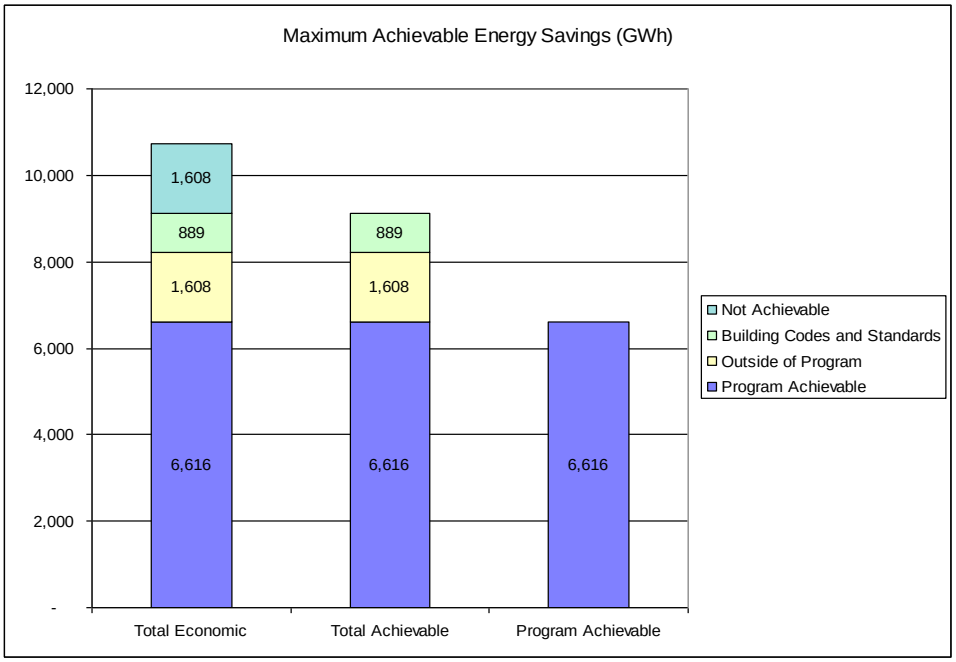
[3] After the first draft of this IRP was submitted, KEMA was asked to perform an analysis on the 2010 *Potential Study* to test the robustness of the cost-effective potential, considering changes in assumed avoided costs. They ran two different sensitivity analyses using different avoided costs to evaluate the cost effectiveness of each technically potential measure. The first sensitivity analysis used updated avoided costs that included avoided energy, capacity, transmission and distribution, renewable energy credits, DRIPE and CO_2 externality costs. The DRIPE and avoided externality costs were taken from Synapse's most recent 2011 Avoided Cost Study; avoided transmission and distribution costs were based on the EDCs' avoided T&D cost studies; and the avoided energy and capacity costs were taken from the 2012 IRP Base Case and Synapse's 2011 Avoided Cost Study. Although the updated avoided energy costs were lower than in the 2007 Avoided Cost Study, the avoided externalities, RECs, and DRIPE were higher, resulting in fairly similar total avoided costs and no significant change to the "Initial Economic Potential" described above. The second sensitivity analysis used the same avoided costs as the first sensitivity except that the DRIPE and CO_2 externality costs were assumed to be half as large. The result of this analysis showed that the updated cost-effective potential was slightly less (8% less energy savings and 17% less capacity savings) than the original potential.

Finally, the *Program Achievable Potential* is calculated by subtracting the savings due to codes and standards, and naturally occurring savings from the Total Achievable Potential, leaving only those savings that can be achieved by the EDC programs. Codes-related savings are estimated as 35% of all cost-effective new construction savings potential occurring on the Total Achievable Potential. Standards-related savings are consistent with the imminent federal lighting standards and account for 50% of economic compact fluorescent light bulb (CFL) savings occurring on the Total Achievable Potential. Finally, the naturally occurring savings refer to those savings that materialize due to market forces and free-rider savings (outside-of-program) and represent 15% of the Total Economic Potential. Figure 2 presents the relationship between the Total Economic, Total Achievable, and Program Achievable Potential.[4]

Figure 2
Relationship between Program Achievable and Total Economic Potential



In this IRP, the Expanded EE resource scenario is based on the full Program Achievable Potential of 6,616 GWh, or 600 GWh/year over 11 years (1.8% of the gross CT load in 2012).

The other alternative considered was to define the Expanded EE Scenario based on the Accelerated Funding Scenario from the Potential Study, which employs expanded program funding to achieve most of the Program Achievable Potential savings (5,910 GWh out of 6,616 GWh). This IRP defines the Expanded EE scenario based on the Program Achievable Potential because that is a fuller measure of the maximum achievable potential that can be achieved over the entire study horizon. It is a fuller measure of the potential compared to the Accelerated Funding Scenario because: (i) it is not constrained by funding availability, and (ii) it is not subject to the limitations of stock turnover and the absence of emerging technologies. Unit costs for achieving the Expanded EE scenario savings are assumed to be equal to those from the

[4] Reproduced from "Connecticut Electric Residential, Commercial, and Industrial Energy Efficiency Potential Study," April (2010), Figure 5-15. "Outside of Program" refers to naturally occurring savings.

Accelerated Funding Scenario, as the *Potential Study* did not quantify these costs for the Program Achievable Potential.

Figure 3 presents the resulting program savings and costs under the Expanded EE Scenario and compares them to the IRP Base Case Scenario savings and costs.

Figure 3
Summary of Expanded EE Program Savings and Costs

		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
SAVINGS FROM EACH YEAR'S NEW MEASURES												
Base Case	*(GWh)*	235	224	218	213	209	205	201	195	194	192	190
Expanded EE	*(GWh)*	601	601	601	601	601	601	601	601	601	601	601
Incremental	*(GWh)*	366	377	383	388	392	397	401	407	408	409	411
Base Case	*(MW)*	30	29	29	29	28	28	28	27	27	27	27
Expanded EE	*(MW)*	125	125	125	125	125	125	125	125	125	125	125
Incremental	*(MW)*	95	96	97	97	97	98	98	98	98	98	99
CUMULATIVE ANNUAL SAVINGS												
Base Case	*(GWh)*	235	459	678	891	1,101	1,305	1,506	1,701	1,895	2,087	2,277
Expanded EE	*(GWh)*	601	1,203	1,804	2,406	3,007	3,609	4,210	4,812	5,413	6,015	6,616
Incremental	***(GWh)***	**366**	**743**	**1,126**	**1,515**	**1,906**	**2,303**	**2,704**	**3,111**	**3,518**	**3,928**	**4,339**
Base Case	*(MW)*	30	60	89	117	145	173	201	228	255	282	309
Expanded EE	*(MW)*	125	251	376	502	627	753	878	1,004	1,129	1,255	1,380
Incremental	***(MW)***	**95**	**191**	**288**	**385**	**482**	**579**	**677**	**776**	**874**	**972**	**1,071**
ANNUAL BUDGET												
Base Case Budget	*($Mil)*	101	99	99	99	99	99	99	100	100	100	100
Expanded EE Budget	*($Mil)*	206	206	206	206	206	206	206	206	206	206	206
Incremental	*($Mil)*	105	107	107	107	106	106	106	106	106	106	106

It is instructive to compare these assumptions to the costs presented in recent C&LM Plans. Figure 4 below compares the resulting costs in the Expanded EE scenario to those in the 2012 CL&M plan's "Increased Savings Scenario," which achieves a similar level of annual savings. (Note: the unit costs are expressed as costs per-one-year-kWh saved to facilitate easier comparison among data sources. These costs appear approximately 12 times larger than the cost per lifetime-kWh saved, corresponding to the average measure life). As the figure shows, the unit costs are similar but slightly higher in the Expanded EE scenario[5] because the more aggressive savings go further up the cost curve. However, the unit cost increase is small because the Expanded EE scenario includes many additional measures in the C&I sector that have a lower monetary cost but considerable non-monetary cost barriers, such as encouraging energy efficient practices.

Figure 4 also compares the Expanded EE Scenario unit costs to those in the 2012 C&LM Plan's "Base Case," which basically represents the business-as-usual. This comparison highlights an important difference between the Expanded EE scenario and the C&LM Plan Base Case and Increased Savings Scenarios as we describe below.

[5] However, the cost per kW saved in the Expanded EE scenario, based on the *Potential Study*, is significantly lower than in the C&LM plan because some of the measures are more peak-focused.

Figure 4
Comparison of *Potential Study* Costs to the 2012 C&LM Plan

	2012 CL&M Plan				2010 Potential Study	
	Base Case		Increased Savings Scenario		Expanded EE	
Annual Savings (GWh)	**235**		**589**		**6,616**	
Costs	*($Mil)*	*($/1yr-kWh)*	*($Mil)*	*($/1yr-kWh)*	*($Mil)*	*($/1yr-kWh)*
Program Cost	$101	**$0.43**	$197	**$0.33**	$2,262	**$0.34**
Participant Cost	$54	**$0.23**	$167	**$0.28**	$2,118	**$0.32**
Total Cost	$155	**$0.66**	$364	**$0.62**	$4,380	**$0.66**

Notes:
1- All costs are expressed in 2012 dollars.
2- The program costs from both the 2010 *Potential Study* and the 2012 C&LM plan include all marketing and administrative costs.

The Expanded EE scenario is an ambitious scenario and a major step forward for an energy efficient future. Similar to all other ambitious initiatives, it will require substantial changes from the *status quo*. First of all, it will require shifting a substantial amount of the cost burden from program budgets to individual participants. While the C&LM Increased Savings case assumes "moderate leverage" to help the participants pay for measure costs with low-cost financing, the Expanded EE costs assumes even greater reliance on financing and other approaches to induce participants to pay a larger share of measure costs. Moreover, as discussed earlier, the Expanded EE scenario includes many additional measures in the C&I sector that have a lower monetary cost but considerable non-monetary cost barriers, such as encouraging energy efficient practices. If these efforts do not materialize and the program costs under Expanded EE remain as high as those in the first year of the Base Case ($0.43 1-yr kWh), the retail rate impacts of the Expanded EE program would be approximately 0.2 cents/kWh higher than currently assumed.

It should also be noted that the 2012 C&LM Base Case unit costs shown in Figure 4 are not representative of the remaining ten years in the IRP Base Case. Although the annual costs remain generally constant, the annual incremental savings gradually decline in the Base Case, as shown in Figure 3. This is mostly because the incremental savings attributable to the CFL-related programs decrease as the penetration of the CFLs increases over time. Thus, the Base Case unit program costs reported in Figure 4 are lower than the average unit program cost of $0.48 per 1-yr kWh saved over the entire 11 years in the IRP Base Case.

If the Expanded EE Scenario costs improvements are not attained and remain as high as in the Base Case 11-year average, at $0.48 per 1-yr kWh saved, the Expanded EE Scenario would require 0.3 cents/kWh more customer rate support than if the assumed cost improvements were attained.

Alternatively, if the full Expanded EE annual program budget ($206 million) were available and the costs per 1-yr kWh saved were the same as the Base Case 11-year average, the savings would be less than in the Expanded EE scenario: 428 GWh annual incremental energy savings (1.3% of the gross CT load in 2012) and 58 MW annual incremental capacity savings, compared to the 601 GWh and 125 MW shown in Figure 3 for the Expanded EE scenario. These annual savings would imply 4,708 GWh and 638 MW cumulative savings in 2022 (compared to 6,616 GWh and 1,380 MW in the Expanded EE scenario). Nevertheless, this lower level of capacity savings would not necessitate replacement capacity over this time period (since there are no local or regional resource adequacy needs even in the Base Case).

As mentioned above, Figure 4 expresses the unit costs from the *Potential Study* in $ per one year kWh saved. Expressing the costs in "$ per one year kWh" rather than "$ per lifetime savings" allows a more direct cost comparison between the *Potential Study* and 2012 C&LM Plan, as the Potential Study did not report the lifetime savings for the Program Achievable Potential. However, we still inferred the lifetime savings from the Potential Study by using the detailed measure data and calculated *Potential Study* costs in "$ per lifetime savings" as $0.028/life-time kWh, $0.026/life-time kWh, and $0.054/life-time kWh respectively for program, participant, and total costs. For C&LP, the Base Case costs in $ per lifetime savings are $0.043, $0.021, and $0.060 and for UI, they are $0.047, $0.027, and $0.060 respectively for program, participant, and total costs.

Future Refinements to Expanded EE Scenarios

This IRP defines the Expanded EE Scenario based on the Program Achievable Potential quantified in the Potential Study. To guide future adjustments to the long-term trajectory of energy efficiency, it would be prudent to conduct an updated potential study. Updates could include: using updated avoided costs; for each measure, gathering and applying Connecticut-specific market data to inform market size, penetration curves, costs, and achievability; identifying specific non-cost barriers and practical ways to overcome those barriers, where applicable.

POLICY APPROACHES TO REALIZING EXPANDED EE SAVINGS

Connecticut's 2007 Public Act 07-242, *An Act Concerning Electricity and Energy*, directed the State to implement "all cost-effective energy efficiency." As discussed in the main report, the analytical results of this IRP strongly support achieving all cost-effective energy efficiency. In addition to reducing total energy costs, greater energy efficiency could help reduce customer rates (especially if new energy efficiency were allowed to help meet a more flexible RPS Class I requirement, as discussed in the IRP main report). Then the question becomes what are the best policy approaches to effectively and efficiently capture the full potential? The most immediate answer is to expand the scope of the EDC programs, which may need to be partly supported by increased customer charges unless the program costs can be funded through new mechanisms such as increasing Class III requirements. In addition, there are other possible innovative approaches that may help achieve the Expanded EE savings, with less reliance on the EDC incentives. These approaches are also aimed at addressing non-monetary barriers through targeted programs, codes, standards, and information provision. Below, we discuss some of these approaches.

Expand Innovative Financing

Customer financing can help to achieve the Expanded EE savings with less reliance on incentives. Connecticut recently established an organization called the Clean Energy Finance and Investment Authority (CEFIA) that functions as a "Green Bank" aimed at providing low-cost financing for clean energy and energy efficiency projects. In this role, CEFIA will leverage public and private funds to drive investment and accelerate clean energy deployment across Connecticut,[6] by granting low interest loans to clean energy projects and energy efficiency projects.

CEFIA's activities build on existing programs. Most recently, the EDCs introduced a new residential loan program that offers subsidized, low interest rate loans to residential customers who make qualified energy efficiency improvements to their homes. This program is also one of the first nationally that offers on-bill repayment provisions. Connecticut's financing programs for the residential, commercial, and industrial sectors include the following:

1. The Energy Conservation Loan (ECL) Program and Multifamily Energy Conservation Loan (MEL) Program after financing at below-market rates to single family and multifamily residential property owners for energy efficiency investments;

2. The HES On-Bill Financing Loan Program offers subsidized, low-interest rate, unsecured loans with on-bill repayment which are provided either through utility or Energy Efficiency Fund;

3. The Small Business Energy Advantage (SBEA) and Municipal Program offers zero percent, on-bill loan repayment to small businesses and municipal customers;

4. The Small Commercial and Industrial Loan Program offers reduced interest loans through a third party financing entity; and

5. The C&I Loan Program offers low-interest subsidized financing for energy efficiency projects costing more than $1,000,000.

Utility and state loan programs are particularly important because commercial banks often show little interest in offering energy efficiency financing to small customers. Typically, commercial banks grant loans only to energy service companies (ESCOs), who manage the projects for large commercial and industrial customers. Unlike commercial banks, credit unions have demonstrated increasing interest in giving loans to small commercial and residential customers for their energy efficiency projects.[7]

With the American Reinvestment and Recovery Act (ARRA) and other stimulus initiatives, such as the Small Business Jobs Act, state and local energy authorities gained new tools to finance energy efficiency efforts. A good example is the "Qualified Energy Conservation Bond" (QECB), which allows state governments to issue bonds to finance energy efficiency projects with the federal government covering a portion of the interest.

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6 http://www.ctcleanenergy.com/CEFIA_2_Page_Brochure.pdf

7 Joel Frehling, "Energy Efficiency Finance 101: Understanding the Marketplace," *ACEEE*, August 2011.

In most states, state housing agencies have emerged as the biggest supporters of energy efficiency projects. Many agencies link low-income housing tax credit incentives to energy efficiency projects and even provide bonus incentives for projects that agree to follow Enterprise Community Partner's Green Communities guidelines.[8] Similarly, state development finance authorities have started to fund energy projects. These agencies can issue bonds and use the proceeds to finance commercial projects. As the bonds include the "moral backing" of the state, the agencies are able to borrow with lower interest rates than the projects are able to do on their own. For example, most recently, the Illinois Finance Authority has been given statutory authority to issue up to $3 billion in "moral obligation" loan guarantees and bonds for the development of energy efficiency and other clean energy project developments in the state.[9]

Accelerate Market Transformation

"Market transformation" refers to the strategic process of intervening in a market to create lasting change in standard practices by removing identified barriers or exploiting opportunities to accelerate the adoption of all cost-effective energy efficiency.[10] Market transformation can be implemented through different channels: (i) interventions that directly address identified market barriers; (ii) competitive market forces, private capital, and information sharing that drive energy efficiency gains; and (iii) collaborations between government, private sector, consumers, and other stakeholders that influence market structure and functioning.[11]

Market transformation is aimed at changing the "business-as-usual" practices to a higher state of energy efficiency. Market transformation can be accelerated through codes and standards and by social marketing strategies. The expectation is that market transformation will result in more market-based implementation of energy efficiency services and products. This is also a clear objective in the Companies' 2012 C&LM plan: "Efforts in 2012 will include an increased emphasis on programs and initiatives that promote sustainable energy management as a core consumer and business value. Ultimately, as the green market grows, programs should move from a primary dependency on public benefit charges to a more self-sustaining industry that can be supplemented, or leveraged, through Energy Efficiency Fund resources."

Induce Behavioral Change through Information

Behavioral change induced by information is one of the ways market transformation operates. As more and more customers become informed about efficient energy practices and their financial and societal benefits, more customers are expected to invest in better measures and practices without relying on incentive mechanisms. However, most customers do not have easy access to detailed information about how to save on energy costs effectively. The most direct way to address this market failure is to find innovative ways to provide information to customers.

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8 *Ibid.*

9 *Ibid.*

10 http://www.aceee.org/topics/market-transformation

11 Sabrina Birner and Eric Martinot, "Market Transformation for Energy Efficiency Products: Lessons from Programs in Developing Countries," *Energy Policy*.

Over the past few years, several private companies started to offer "behavior-based programs," mostly for residential customers. These behavior-based programs have been gaining traction with utilities and commissions recently and are mostly known for their "home energy reports." In these monthly or quarterly reports, customers are provided personalized information on energy usage in their homes; comparison to similar households in the neighborhood; and quick tips that can quickly yield energy savings. Increased awareness of energy usage and knowledge about specific energy saving opportunities enable users to act in their own financial interest. Empirical studies report that participants achieve annual energy savings in the range of one to three percent.[12] More recently, a new study found that these impacts may persist over time; however more evidence is needed to be able to conclusively claim that the impacts persist over time.[13]

Mandating additional energy efficiency information labels on manufactured products is another way of addressing the market failure in information provision. If these labels provide clear, helpful, and standardized information about the efficiency of products, customers can make on-the-spot comparisons and make more informed purchase decisions. As customers start making purchase decisions not only based on price and quality of the products, but also on the energy efficiency rating of the products, the expectation is that the inefficient products will be driven out of the market. The ultimate goal is to make manufacturers compete on the energy efficiency of their products, in addition to other attributes such as quality and price.

Finally, public outreach campaigns, curriculums in elementary, secondary and high schools, collaborations with universities and technical schools, and advertising campaigns involving local celebrities also help address the information problem and incentivize more efficient behavior.

Introduce More Aggressive Codes and Standards

An effective way of accelerating the market transformation is to introduce more aggressive codes and standards. Current codes and standards mostly dictate baseline measures that have sub-optimal levels of energy efficiency. Moreover, most building codes are not necessarily strictly enforced. Some improvement is possible through more rigorous enforcement.

However, existing codes generally address only new construction, which covers a small fraction of the building stock. Potentially much more savings could be achieved if codes were imposed on existing buildings upon change of ownership. Such codes would have to be set carefully in order not to impose prohibitively high costs on sellers of buildings that are difficult to retrofit.

A complementary policy approach would be to mandate old and new building owners to disclose energy usage and efficiency statistics of their buildings. These statistics can be standardized and may include utility bills, building envelope characteristics, and other measures that indicate the energy efficiency level of a building. It is expected that this kind of disclosure will incentivize building owners to make efficiency investments, as buyers develop an interest in higher efficiency residences and office spaces.

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[12] See for more information, *The Brattle Group*, "Measurement and Verification Principles for Behavior-Based Efficiency Programs," May 2011, prepared for OPOWER.

[13] Hunt Allcott, "Social Norms and Energy Conservation," *Journal of Public Economics*, 2011.

Explore Efficiency-Inducing Rate Structures

Rate designs can provide incentives to use energy efficiently. One such rate design, dynamic pricing, is receiving widespread consideration, especially as more and more utilities pursue investments in advanced metering infrastructure (AMI). Although dynamic pricing rates are very effective in reducing peak load, they are not likely to have a sizable impact on overall energy consumption as the higher critical peak rates are only in effect during a small number of hours. There is another type of rate design, inclining block rates, which can be effective in promoting energy efficiency. Under such a rate design, the price of electricity (at least the transmission and distribution components) rises with increasing usage. However, rather than rising uniformly with each kWh of consumption, the rate rises when the consumption exceeds a certain threshold. Under such a rate structure, customers have incentive to use energy more efficiently and realize most of their energy consumption in the first and least expensive block of usage.

Inclining block rates have several advantages in combination with other initiatives. First, it is a low-cost option as it does not require smart meters, incentive or rebate payments, or significant administrative costs. Second, it improves the economics of other energy efficiency measures. It creates a faster payback for higher efficiency equipment installations and increases the value of in-home information display technologies. Finally, it is customer-friendly and can be deployed universally.[14] Faruqui (2008) reports that the amount of load response depends on the price elasticity of energy consumption and estimates short-run load overall energy savings in the range of 0.5 to 5.9% based on Monte Carlo simulations.[15]

However, there are also some challenges involved in implementing inclining block rates. First, inclining block rates do not necessarily directly correspond to the system costs which can lead to economically inefficient behavior. Second, managing customer bill impacts will be important under the inclining block rates structure. Those customers who respond to the lower pricing incentive in the first block would reduce their monthly usage and hence their monthly bills, but customers who do not respond to inclining block rates may end up with higher bills. Before implementing an inclining block rate structure, it is advisable to determine customer segments that can be adversely affected by these rates and potentially look for ways to mitigate those adverse impacts. Finally, there are concerns to the extent that inclining block rates may discourage the adoption of plug-in electric vehicles or efficient heat pumps, but it is possible to design alternative rates such as time-of-use rates or separate metering for such customers.

The steps that must be followed in designing an effective inclining block rate structure usually involve balancing the tradeoffs among conflicting objectives such as encouraging more efficient energy consumption, more accurately representing system marginal costs, promoting social objectives, protecting vulnerable customers, and ensuring bill stability.[16]

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[14] Ahmad Faruqui, "Inclining Toward Efficiency," Public Utilities Fortnightly, August 2008.

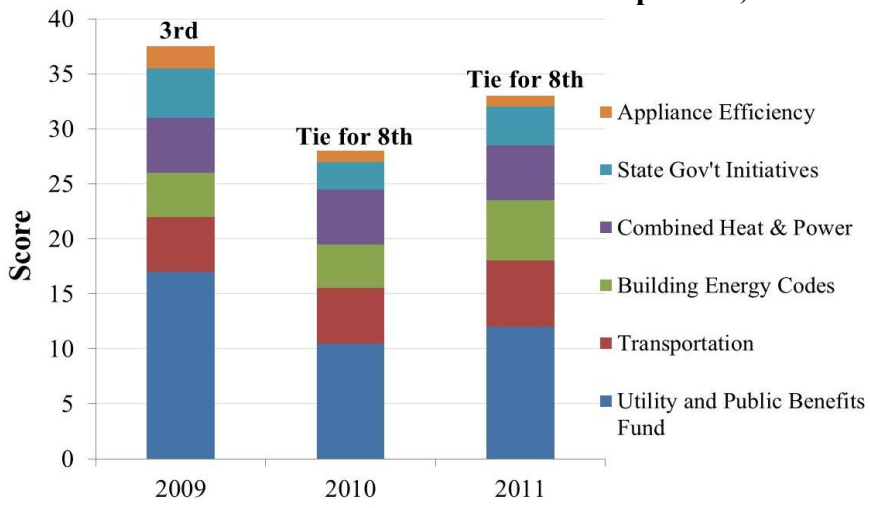
[15] *Ibid.*

[16] These steps are described in detail in Faruqui, *op. cit.*.

CONNECTICUT'S ENERGY EFFICIENCY RANKING

Connecticut's successful record in implementing energy efficiency programs and policies is manifested in the rankings of American Council for an Energy Efficient Economy (ACEEE). ACEEE evaluates each state based on its energy efficiency program spending, energy savings, targets, development of incentives, and removal of barriers. According to ACEEE's 2011 State Energy Efficiency Scorecard, Connecticut remained tied for 8th with Minnesota but improved its total score by 5 points from 2010. From 2009 to 2010, Connecticut dropped 9.5 points in its total score, moving its ranking from 3rd to 8th. Figure 3 demonstrates the composition of Connecticut's total score for 2009-2011.

Figure 3
Connecticut's ACEEE State EE Scorecard Comparison, 2009-2011



The three categories with a net loss in performance from 2009 to 2010 are:

1. Utility and Public Benefits Fund Efficiency Programs and Policy Score (Maximum possible score is 20). It is made up of five sub-categories: (i) electricity program spending; (ii) electricity savings; (iii) gas program spending; (iv) EE targets; and (v) utility incentives/removal of disincentives. Connecticut fell in every sub-category except "gas program spending" in which it increased by 0.5 points. The total score dropped from 17 in 2009 to 10.5 in 2010.

2. State Government Initiatives Score (Maximum possible score is 7). It is made up of three sub-categories: (i) financial and information incentives; (ii) lead by example (an aggregate of building requirements and efficient fleets); (iii) RD&D. Connecticut fell in every sub-category. The total score dropped from 4.5 in 2009 to 2.5 in 2010.

3. Appliance Efficiency Score. The appliance efficiency score methodology changed between 2009 and 2010; however, the point structure remained constant (states could only receive a maximum of three points). Due to a methodology change from 2009-2010, it is difficult to draw a comparative conclusion for the appliance efficiency score.

Connecticut's EE score improved in all three categories from 2010-2011, with the exception of the Appliance Efficiency Score, which remained numerically constant. It is important to recognize that, although the ACEEE score is an important metric for progress in energy efficiency program implementation, it should be interpreted carefully as it is a relative metric. Improvement in a score may be due to other states falling behind, or reduction in a score may be due to other states improving more. Other metrics such as incremental year-over-year program savings, $/kWh cost of achieving energy savings, or whether the target savings are met may be more useful. As long as the state energy efficiency objectives are met, the changes in the ACEEE rankings may carry only secondary importance.

APPENDIX D

RENEWABLE ENERGY

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OVERVIEW

This Appendix focuses on issues relating to Connecticut's and New England's future supply and demand for renewable energy technologies to satisfy the region's renewable portfolio standards (RPS) and further energy diversity and environmental goals.. This Appendix is intended to provide the analytical support to the main IRP report, not to provide a specific policy conclusion. To conduct the analysis, we constructed the following future resource scenarios to analyze the tradeoffs between using different policy tools to achieve similar objectives:

- **"Base Case" Scenario** with projections of renewable resource build-out over the next ten years based on information that is currently available, consistent with recent history
- **"Full Renewables" Scenario** with projection of renewables build-out to meet the region's Class I REC requirements
- **"Low Renewables" Scenario** that shows a very low projection of the regional renewable build out

Several metrics are used to evaluate the effects of each scenario: Connecticut's customer costs, resource costs, emissions, employment and other macroeconomic indicators, as well as regional emissions. Thus, our conclusions and recommendations regarding how Connecticut can best meet its energy and environmental goals through renewable energy strategies are derived from these metrics.

CONNECTICUT'S RENEWABLE ENERGY REGULATIONS, AND THE DEMAND THEY CREATE

Connecticut's existing Renewable Portfolio Standards (RPS) requires electric suppliers to procure increasing shares of their sales from qualifying renewable resources. It has a tiered structure with three classes as summarized below:

- **Class I** resources include energy derived from solar, wind, fuel cell, methane gas from landfills, ocean thermal, wave, tidal, run-of-river hydropower (<5MW, began operation after July 1, 2003), and sustainable biomass (NO_X emission <0.075 lbs/MMBtu of heat input, <500 kW, began operation after July 1, 2003).
- **Class II** resources include biomass (NO_X emission <0.2 lbs/MMBtu of heat input, began operation before July 1, 1998), small run-of-river hydroelectric (<5MW, began operation before July 1, 2003), and trash-to-energy facilities.
- **Class III** resources include customer-sited combined heat and power (with operating efficiency >50%, facilities installed after January 1, 2006), waste heat recovery systems (installed on or after April 1, 2007), electricity savings from conservation, and load management programs (began on or after January 1, 2006).

While the Class I Renewables analysis contained in this report treats New England as a single market, Connecticut's RPS has some unique eligibility characteristics that may create some disparities between Connecticut and other New England states. A subclass of Class I RECs is only eligible in Connecticut.

- Aside from small hydro and small biomass facilities, the definition of Class I "new" renewable resources in Connecticut does not specify a "vintage" requirement, whereas Class I renewables in other New England states must have entered into service after a certain date to be eligible to meet RPS requirements.[1,2] As a result, existing resources that were built before 1998, such as existing landfill gas, wind, and low-emission biomass plants qualify as Class I resources only in Connecticut.
- Natural-gas powered fuel cells qualify as Class I resources in Connecticut, but not in other New England states.
- Connecticut allows the generation of Class I RECs by some natural gas fired generators that import landfill gas from outside of the state via interstate natural gas pipeline.

In addition, the implementation of Connecticut's renewable policies has the following features:

- The RPS requirements for the Electric Distribution Companies, CL&P and UI, are passed on to wholesale suppliers. CL&P and UI receive RECs from the wholesale suppliers of standard service and last resort service and use these RECs to show compliance with the RPS.
- CL&P receives Class I RECs through a legacy long-term contract[3] and in turn sells them in the regional market.
- Both CL&P and UI will purchase Class I RECs through their assigned Project 150 contracts, and other contracts as required by law.
- Class II and III are met by wholesale suppliers. The EDCs sell Class III RECs generated by the Conservation and Load Management (C&LM) programs through competitive request for bids.
- Retail suppliers are responsible for their own RPS compliance
- The Alternative Compliance Payment (ACP) acts as a price ceiling on the REC prices
    - Connecticut's ACP for Class I and II requirements is fixed at $55/MWh, and for Class III at $31.00

[1] Run-of-river hydropower facilities with a capacity of less than 5 MW and sustainable biomass facilities with a capacity of less than 500 kW qualify as Class I resources in Connecticut if they began operation after July 1, 2003. Section 16-1(a)(26) of Connecticut State Statute.

[2] Massachusetts and Rhode Island's vintage requirement is December 31, 1997, Maine's is September 1, 2005, and New Hampshire's is January 1, 2006.

[3] CL&P has a long-term contract instituted under the Public Utility Regulatory Policies Act (PURPA).

- Unlike Connecticut, the rest of the states in New England with a Class I RPS requirement currently have ACPs of $62/MWh, escalating at the consumer price index.

Because Connecticut has very limited wind resources located in the state, its primary resources are fuel cells and solar PV, both of which are currently relatively more expensive than other renewable resource available in the region. Thus, in addition to the above features, Connecticut has "in-state" programs that help promote the development of renewable energy technologies within the state.

- Project 150 is an initiative aimed at increasing renewable supply in Connecticut by at least 150 MW of installed capacity. On September 7, 2011, Public Utilities Regulatory Authority (PURA) reported to the General Assembly regarding the status of Project 150 long-term renewable energy contracts (Docket No. 11-07-06). In that report, PURA stated that of the 14 approved projects totaling 159.8 MWs, only 4 projects totaling approximately 47 MW appear to be financed or moving forward to completion as required by the contracts.
- Public Act 11-80 established the Clean Energy Finance and Investment Authority (CEFIA) to promote investment in clean energy sources; to foster the growth, development, and commercialization of clean energy sources and related enterprises; and to stimulate demand for clean energy sources.
- Other Connecticut-specific programs include:
  - **Residential solar program:** Section 106 of the Public Act 11-80 requires CEFIA to develop a solar incentive program that will support at least 30 MW of new residential solar capacity by December 31, 2022.
  - **"ZREC" program:** Section 107 of the Act requires that utilities enter into 15-year contracts for RECs from "zero-emission" Class I renewable energy resources (with a cumulative payment of approximately $720 million).
  - **"LREC" program:** Section 110 of the Act requires that utilities enter into 15-year contracts for RECs from "low-emission" Class I renewable energy resources (with a cumulative payments of approximately $300 million).
  - **Other Class I projects:** Under Section 127 of the Act, developers and utilities may submit proposals for up to an aggregate of 30 MW of new Class I renewable energy sources. In December 2011, DEEP)announced its selection of two 5 MW solar energy projects (East Lyme Solar Park and Somers Solar Center) for long-term power purchase agreements, representing one-third of the renewable generation procurement mandated by the Act.

Figure 1 summarizes Connecticut's RPS targets based on the percentage of load for each class.

Figure 1
Connecticut RPS Requirements

Year	Class I	Class II or Class I (add'l)	Class III	Total
2011	8.0%	3.0%	4.0%	15.0%
2012	9.0%	3.0%	4.0%	16.0%
2013	10.0%	3.0%	4.0%	17.0%
2014	11.0%	3.0%	4.0%	18.0%
2015	12.5%	3.0%	4.0%	19.5%
2016	14.0%	3.0%	4.0%	21.0%
2017	15.5%	3.0%	4.0%	22.5%
2018	17.0%	3.0%	4.0%	24.0%
2019	19.5%	3.0%	4.0%	26.5%
> 2020	20.0%	3.0%	4.0%	27.0%

Source: Conn. Gen. Stat § 16-245a et seq. and Public Act No. 07-242, § 40-44.

Figure 2 summarizes the current Class I programs in Connecticut, including the estimated renewable capacity additions and cumulative payments.

Figure 2
Summary of Current Class I Programs in Connecticut

	Quantity	Payments (cumulative nominal over life)
Existing Programs		
Project 150	About 47 MWs	About $810 million
PA 11-80 Programs		
Residential Solar PV (Sec. 106)	Minimum of 30 MWs	About $150 million
Zero Emission Class I Projects (Sec. 107)	About 250 MWs	About $720 million
Low Emission Class I Projects (Sec. 110)	About 25 MWs	About $300 million
Other Class I Projects (Sec. 127)	Up to 30 MWs	TBD
Total Existing and PA 11-80	**About 380 MW**	**> $2 Billion**

RENEWABLE PORTFOLIO STANDARDS IN NEW ENGLAND

All six New England states have set explicit renewable energy targets through state legislative and regulatory processes. Wind resources that deliver power to New England (the Class I renewable resource with the most abundant supply potential in the region) can meet all six states' Class I requirements; and the overall regional market dynamics depend on the regional supply and the collective requirements set by the six states. Such a regional market allows RECs to be traded across states. Vermont currently does not have a state mandate for renewable energy purchases and the RECs produced from the renewable resources built to support Vermont's goals can be used to meet other New England states' RPS requirements. Thus, Vermont's renewable energy goals do not create additional demand for new Class I renewable resources in New England, although they can serve as a source of supply.

Figure 3 summarizes the renewable energy technologies designated for RPS in New England states, and Figure 4 plots the magnitude of region-wide demand for Class I-equivalent resources through 2022, which increases from 5.0% of retail load in 2011 to 14.3% by 2022. As seen on Figure 4 (a), Connecticut has the most ambitious Class I RPS target as a percentage of load (20% in 2020), and its total GWh requirement is second only to Massachusetts in New England (Massachusetts' Class I RPS target is 15% in 2020, but its retail load is approximately twice the Connecticut's load).

Figure 3
Summary of Renewable Energy Technologies Designated for RPS in New England States

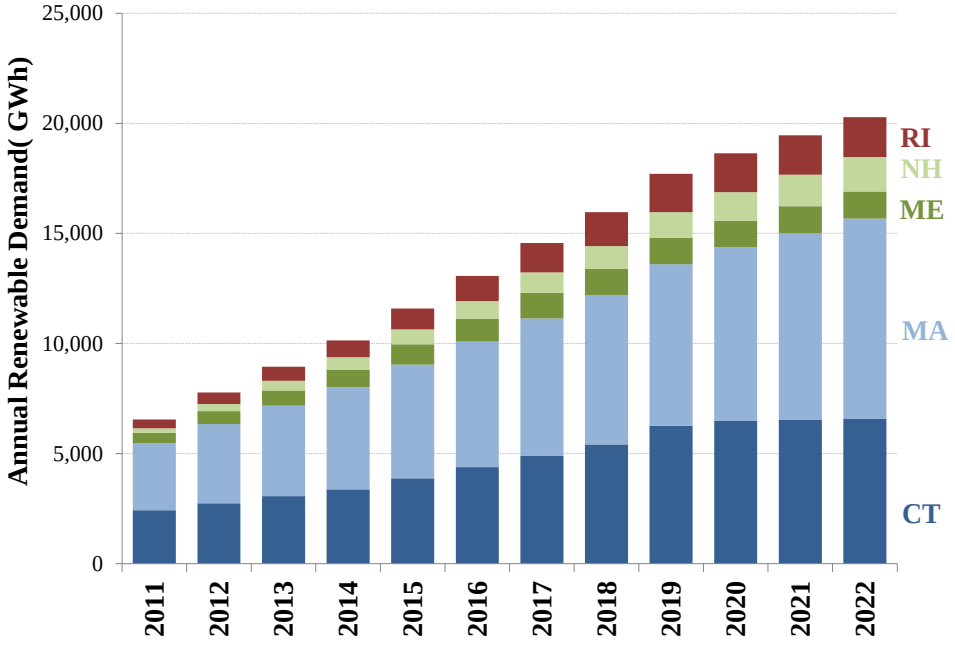
Technology	CT Classes			MA Classes			ME Classes		RI	NH Classes			
	I	II	III	I	IIa	IIb	I	II		I	II	III	IV
Solar thermal	✓			✓	✓		✓		✓	✓	✓		
Photovoltaic (PV)	✓			✓	✓		✓		✓	✓	✓		
Ocean thermal	✓			✓	✓				✓	✓			
Wave	✓			✓	✓				✓	✓			
Tidal	✓			✓	✓		✓		✓	✓			
Marine or hydrokinetic				✓	✓								
Hydro	<5 MW	<5 MW		<25 MW	<5 MW		✓	✓	<30 MW	incremental			<5 MW
Wind	✓			✓	✓		✓		✓	✓			
Biomass, biofuels	Sustainable, advanced conversion low NO_X emissions	✓		Low-emission, advanced technology	✓		✓	✓	✓ Includes cofiring with fossil fuels	Low NO_X, and PM emissions		<25 MW, low NO_X, and PM emissions	
Landfill gas	✓			✓	✓		✓		✓	✓		✓	
Anaerobic digester				✓	✓				✓	✓		✓	
Fuel cells	✓			with renewable fuels	✓		✓		with renewable resources				
Geothermal				✓	✓		✓		✓	✓			
Municipal solid waste		✓				✓		✓with recycling					
Cogeneration, combined heat and power (CHP)			Customer sites, minimum 50% fuel efficiency	✓				✓					
Energy efficiency			✓										

Source: ISO-NE 2011 Regional System Plan, October 21, 2011.

Figure 4
New England Class I-Equivalent RPS Requirements
(a) Percentage of Retail Load

State	Class	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
CT	Class I	8.0%	9.0%	10.0%	11.0%	12.5%	14.0%	15.5%	17.0%	19.5%	20.0%	20.0%	20.0%
MA	Class I	6.0%	7.0%	8.0%	9.0%	10.0%	11.0%	12.0%	13.0%	14.0%	15.0%	16.0%	17.0%
ME	Class I	4.0%	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
NH	Class I+II	2.1%	3.2%	4.2%	5.3%	6.3%	7.3%	8.3%	9.3%	10.3%	11.3%	12.3%	13.3%
RI	All	3.5%	4.5%	5.5%	6.5%	8.0%	9.5%	11.0%	12.5%	14.0%	14.0%	14.0%	14.0%
VT	All	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
TOTAL		**5.0%**	**5.9%**	**6.7%**	**7.6%**	**8.7%**	**9.7%**	**10.7%**	**11.7%**	**12.8%**	**13.4%**	**13.9%**	**14.3%**

(b) Annual GWh



Sources and Notes:

[1] Percent requirements based on state RPS rules and regulations that are currently in place, and do not include renewable goals in Vermont. "Total" reflects the share of New England load that needs to be served by RPS qualified renewable resources.

[2] RPS demand is calculated based on CELT 2011 load forecast, net of Passive Demand Resources and any other incremental energy efficiency assumed in our "Base Case". Share of municipal-owned utilities in Connecticut, Massachusetts, and Rhode Island are excluded, as they are not required to meet the state RPS.

Like Connecticut, several other New England states have unique features of their own. Specifically, Massachusetts has set several tiers of renewable energy goals, including an in-state solar "carve-out" with a target of 400 MW by 2020. Although the resulting solar resources help Massachusetts meet its Class I RPS requirements, they receive payments in the form of solar-RECs in a separate Massachusetts-administered program. Thus, Massachusetts' solar program represents a separate market from New England Class I renewable resources, one that has its own price.

UNCERTAINTIES IN RENEWABLE ENERGY REGULATIONS AND REC MARKET

The development of renewable energy in New England's faces significant future uncertainties. Specifically, these uncertainties involve:

- Potential changes in the magnitude and qualifications for federal tax credits;
- Credit market uncertainties and the relative ease of and cost to finance new projects;
- Potential changes in state RPS policies in the region, including possible changes in the qualifications of various technologies (*e.g.*, biomass in Massachusetts), the magnitude of the state requirements, and the magnitude of supply resulting from state-specific programs throughout the region that support only their respective in-state renewables;
- The magnitude of transmission enhancements and the associated costs necessary to support certain levels of renewable build-out;
- The potential operational effects and therefore resource needs and costs for compensating variable generation such as wind on the grid[4];
- The potential for changes in the economics of renewable resources and other low-emissions technologies; and
- Legislative changes to the class definitions of renewable resources, which can affect the REC prices across the New England states.

RENEWABLE ENERGY SUPPLY IN NEW ENGLAND

While the technical potential in the region remains high, due to the economic downturn, lower load and demand for renewable resources, and sustained low natural gas prices, and project financing for new projects has become more challenging to obtain. In addition, Maine and Connecticut have legislative mandates to re-examine the merits of their existing RPS policies, which create uncertainties in the REC market.[5,6] On the other hand, the implementation of long-term contracts for a portion of Massachusetts Class I requirements has provided more security for a few projects in the queue. Below, we describe the current status of Class I renewables development in New England.

Existing Renewable Capacity in New England

Existing Class I renewable capacity in New England is approximately 1.2 GW (excluding qualified imports from neighboring regions). This is about 400 MW, or roughly 50%, increase from two years ago (shown in the 2010 IRP). Figure 5 presents the current renewable capacity of

[4] GE Energy, Final Report: New England Wind Integration Study, prepared for ISO-NE, December 5, 2010.

[5] "An Act to Reduce Energy Prices for Maine Consumers," 125th Maine Legislature, LD1570-SP0501, PUBLIC Law, Chapter 413, Section 6.

[6] "An Act Concerning the Establishment of the Department of Energy and Environmental Protection and Planning for Connecticut's Energy Future," Conn. Public Act No. 11-80, Section 129 (June 17, 2011)

Class I resources in New England, primarily based on information provided by each of the New England states.

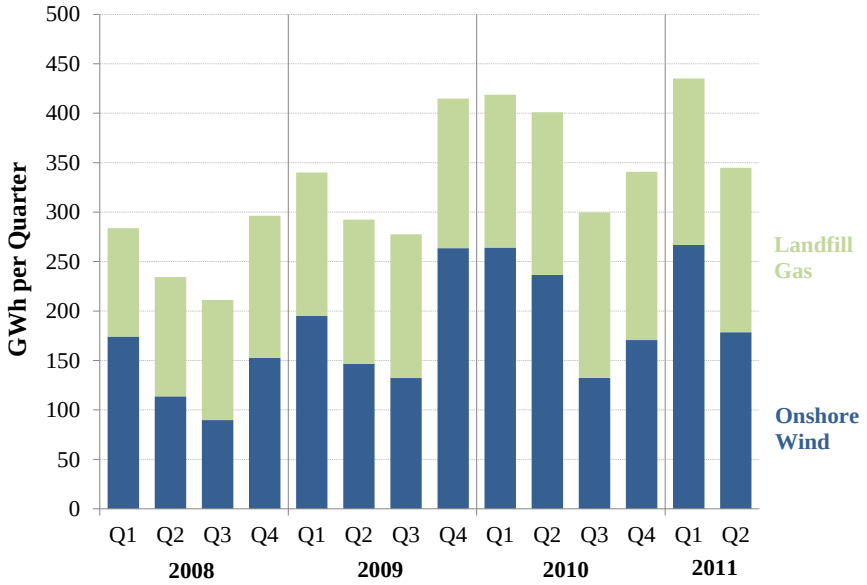
- Biomass makes up nearly half of the total MW capacity (about 570 MW);
- Onshore wind grew from about 140 MW in 2009 to more than 320 MW in 2011 (mostly located in Maine);
- About 100 MW of new solar PV have been added since end of 2009, increasing the regional capacity to about 130 MW (with the majority of new development occurring in Massachusetts);
- Capacity of other sources such as landfill gas, fuel cells, and small hydro has remained low, similar to 2 years ago (shown in the 2010 IRP); and
- Connecticut has only 66 MW renewable capacity (about 5% of total in New England) although it accounts for more than a third of the Class I RPS demand in the region.

Figure 5
Existing Class I Resources by State and Technology
(Nameplate Capacity in MW)

Technology	**Regional Supply by State**						
	CT	*MA*	*ME*	*NH*	*RI*	*VT*	***TOTAL***
Biomass/ Biofuels	0	27	322	158	0	62	**569**
Fuel Cells	5	0	0	0	0	0	**5**
Landfill Gas	13	46	10	27	21	11	**128**
Wind	0	27	270	24	2	0	**323**
Small Hydro	10	9	21	22	2	23	**87**
Solar PV	38	75	0	7	2	7	**129**
TOTAL	**66**	**185**	**623**	**239**	**27**	**103**	**1,242**

An additional source of supply in New England arises from imports. These imports account for renewable power produced outside of and delivered to the ISO-New England's system. Historical data shows that Class I REC imports into New England were about 1,500 GWh in 2010 (~10% increase from 2009). Almost all of the imports are from onshore wind and landfill gas resources in New York and Canada. Figure 6 plots the quarterly imports for renewable energy, based on the data published by NEPOOL Generation Information System (GIS).

Figure 6
Class I REC Imports into New England



Source: Calculated based on data from NEPOOL Generation Information System (GIS).

Renewable Capacity Under Development

According to the 2011 ISO-New England Regional System Plan, approximately 3,900 MW of renewable generating capacity are in the ISO-NE generation interconnection queue, most of which are proposed wind projects. However, historical information shows that many of the projects in the queue are not likely to be built for a variety of reasons. In fact, ISO-New England estimated that about 52% of all the projects, and 40% of the wind projects that have entered the ISO's interconnection queue had been withdrawn (almost 70% of capacity).[7]

To estimate a projection of the renewable energy supply in the region, we have used the most current status on proposed renewable projects provided in Ventyx Energy's Velocity Suite Generating Unit Capacity database. Below we summarize our assumptions and Figure 7 shows the resulting estimates for the renewable supply resources likely to materialize through 2015, which are used in the Base Case Scenario. Our assumptions included:

- Probabilities for each proposed renewable project reaching completion, based on current development status.
- Cape Wind (468 MW) and Deepwater Block Island (18 MW) offshore wind projects will be in-service by 2015.
- 47 MW of the Connecticut's Project 150 projects will be developed.[8]

[7] ISO-NE 2011 Regional System Plan, October 21, 2011, pages 133-134.

[8] Public Utilities Regulatory Authority, Final Decision on the Status of Project 150 Long-Term Renewable Energy Contracts, Docket No. 11-07-06 (September 7, 2011).

- Incremental capacity for solar PV, fuel cells, and small onshore wind projects are based on targets set by state programs (such as Connecticut's ZREC, LREC, and residential solar PV programs, and Massachusetts' solar programs).

Figure 7
Cumulative Existing and Planned Class I Capacity in New England
(Nameplate Capacity in MW)

Technology	Existing Supply	2011	2012	2013	2014	2015
Biomass/ Biofuels	569	636	668	675	675	680
Fuel Cells	5	5	6	11	16	39
Landfill Gas	128	131	132	132	132	132
Onshore Wind	323	460	564	644	692	770
Offshore Wind	0	0	0	0	0	486
Small Hydro	87	87	88	88	89	89
Solar PV	129	129	169	238	314	384
Imports	382	420	459	497	535	573
TOTAL	**1,624**	**1,870**	**2,086**	**2,286**	**2,453**	**3,153**

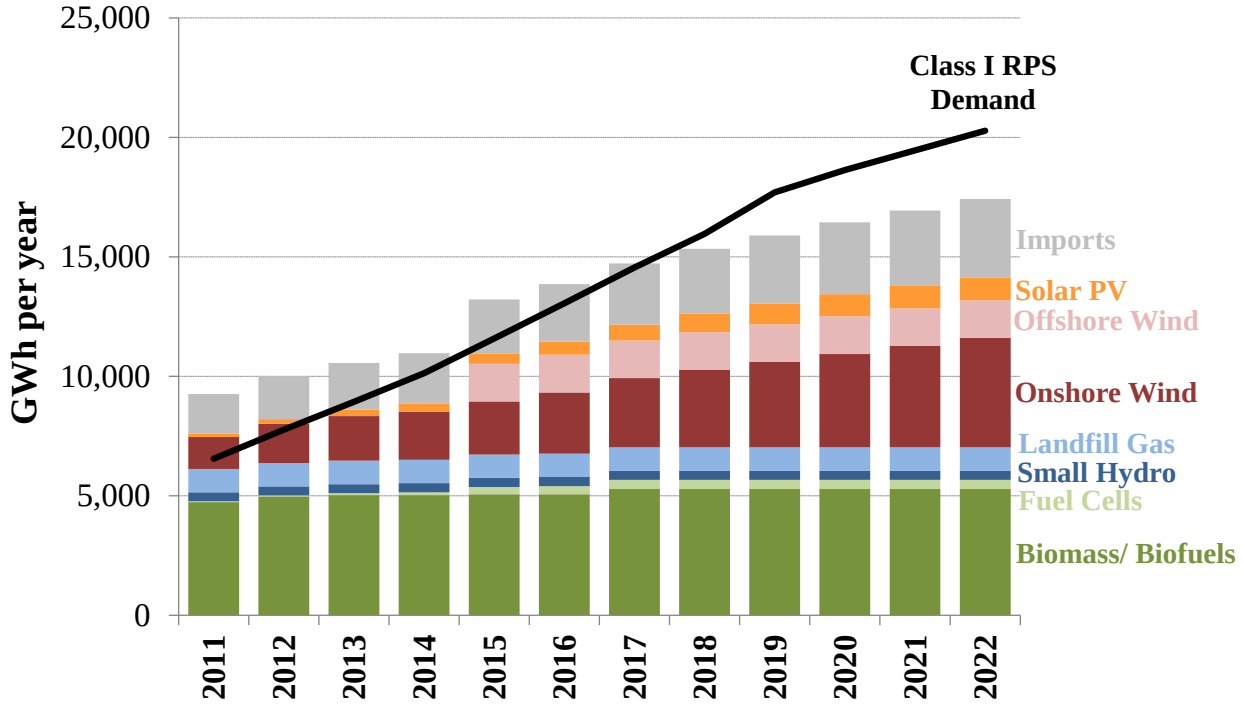
Expected Capacity Additions Beyond 2015 in Base Case Scenario

For years beyond 2015, the Base Case represents the "most likely" trajectory of renewable energy development in New England based on current available information. Accordingly, we assume a renewable expansion path that is consistent with recent historical trends and expected near-term additions.

- Onshore wind capacity expands based on recent historical and near-term forward-looking trend of ~115 MW per year (representing the primary growth of renewable supply in the region).
- Solar capacity growth based on state-specific targets (from Massachusetts and New Hampshire) and planned programs (such as Connecticut's ZREC, residential solar PV programs, and possible utility-developed projects).
- Biomass, fuel cells, offshore wind, and small onshore wind resources would likely require explicit financial support in addition to REC payments and, therefore, are assumed to grow only if specific programs would support them (*e.g.*, projects supported by Connecticut's Project 150, ZREC, and LREC programs).
- No new landfill gas and small hydro resources are developed because very little new capacity was added in recent years, and there are no publicly proposed projects (suggesting that these resources may have already been developed to their economic potential).
- REC imports from New York and Canada are assumed to increase at ~10% per year relative to 2010 actuals, consistent with recent historical growth rates.

The resulting supply and demand balance is presented in Figure 8 below. As shown, we project that renewable development in the Base Case exceeds RPS target levels through 2017, but will begin to fall short of RPS demand beyond 2017 (by ~3,000 GWh in 2022, or about 14% of the demand for RECs). This implies that REC prices would gradually increase across New England, and perhaps reach alternative compliance payment (ACP) levels. Biomass generation, which currently makes up over half of the Class I production in New England, is expected to remain relatively flat and is forecast to account for about 30% of total renewable generation by 2022. In addition, wind resources (onshore and offshore) are expected to grow over the same period and are forecast to contribute about 35% of the total by 2022.

Figure 8
New England Class I Renewable Resource Supply and Demand Balance in the Base Case



Alternative Scenarios Considered

The Base Case assumes that Class I renewable energy resources will develop along a trajectory consistent with recent history. However, to test the potential effects of alternative scenarios, we evaluated the following:

- **Full Renewables:** The region as a whole meets the current aggregate renewable requirements. In this scenario, the gap between the supply and demand for Class I renewable energy resources in the Base Case is met by increasing onshore wind resources located in various New England states, with resulting Class I REC prices set by the estimated payments needed for onshore wind resources.

- **Low Renewables:** In this scenario, the region becomes severely constrained in its renewable energy build-out either because of siting, financing, transmission limitations, or other reasons, with resulting Class I REC prices rise to the Connecticut's or the Regional ACP price, depending on the level of shortage.

Figure 9 and Figure 10 present and compare the amounts of renewable supply and demand assumed in various scenarios as described above.

Figure 9
Summary of New England Class I Renewable Energy Generation

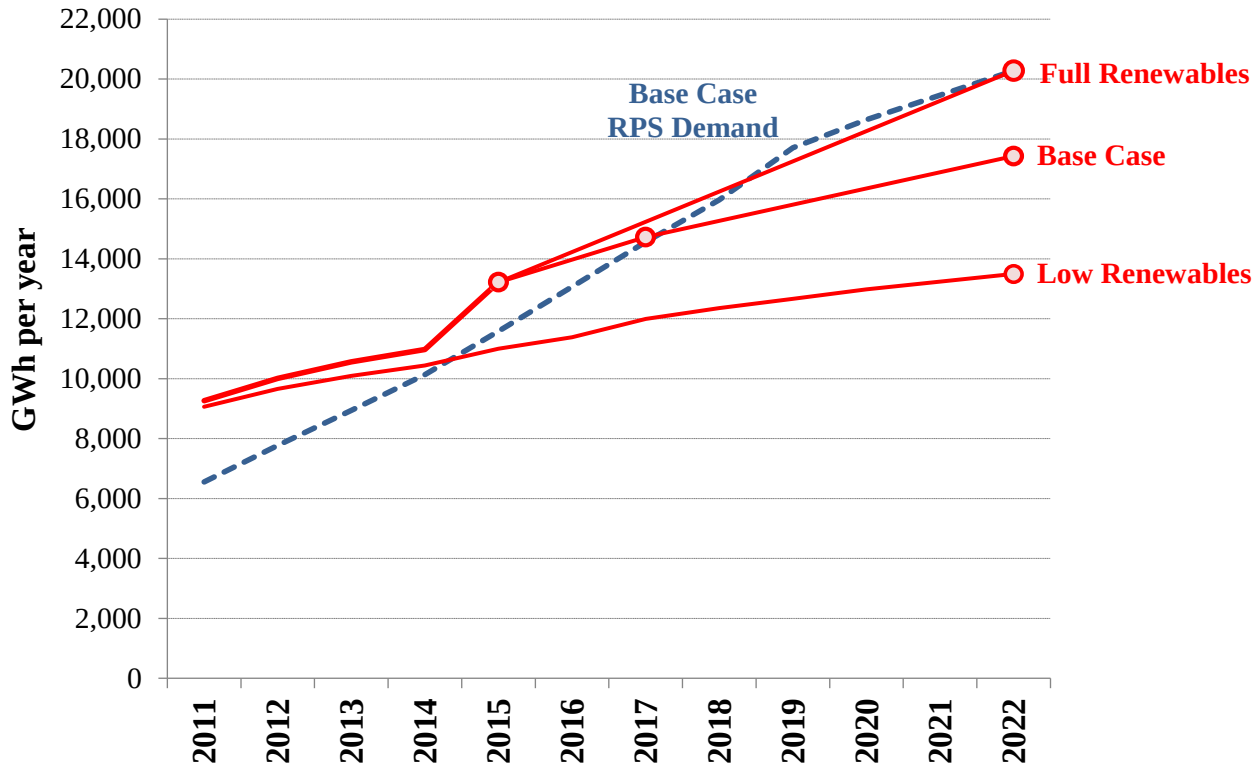


Figure 10
Summary of Class I Renewable Resource Build-out in Connecticut and New England
(Nameplate Capacity MW, Base Case Futures)

Renewable Technology	Existing Renewable Capacity 2011 (MW)	New Renewable Capacity Additions: Base Case 2015 (MW)	Base Case 2017 (MW)	Base Case 2022 (MW)	Full Renewables 2022 (MW)	Low Renewables 2022 (MW)
Connecticut						
Biomass/ Biofuels	0	0	30	30	30	30
Fuel Cells	5	33	42	42	42	42
Landfill Gas	13	3	3	3	3	3
Onshore Wind	0	9	16	22	29	6
Offshore Wind	0	0	0	0	0	0
Small Hydro	10	0	0	0	0	0
Solar PV	38	123	218	291	291	291
Connecticut Total	**66**	**169**	**310**	**389**	**396**	**373**
ISO New England						
Biomass/ Biofuels	569	111	141	141	141	141
Fuel Cells	5	33	42	42	42	42
Landfill Gas	128	4	4	4	4	4
Onshore Wind	323	446	683	1,263	2,249	446
Offshore Wind	0	486	486	486	486	0
Small Hydro	87	2	2	2	2	2
Solar PV	129	255	458	697	697	697
Imports	382	191	267	459	459	459
ISO-NE Total	**1,624**	**1,529**	**2,084**	**3,095**	**4,081**	**1,791**

(Annual GWh, Base Case Futures)

Renewable Technology	Existing Renewable Capacity 2011 (GWh)	New Renewable Generation Additions: Base Case 2015 (GWh)	Base Case 2017 (GWh)	Base Case 2022 (GWh)	Full Renewables 2022 (GWh)	Low Renewables 2022 (GWh)
Connecticut						
Biomass/ Biofuels	1	0	223	223	223	223
Fuel Cells	40	261	335	335	335	335
Landfill Gas	98	22	22	22	22	22
Onshore Wind	0	16	28	39	51	11
Offshore Wind	0	0	0	0	0	0
Small Hydro	42	2	2	2	2	2
Solar PV	43	140	249	331	331	331
Connecticut Total	**223**	**442**	**859**	**953**	**965**	**925**
ISO New England						
Biomass/ Biofuels	4,238	828	1,051	1,051	1,051	1,051
Fuel Cells	43	261	335	335	335	335
Landfill Gas	955	28	28	28	28	28
Onshore Wind	936	1,286	1,966	3,643	6,496	1,286
Offshore Wind	0	1,575	1,575	1,575	1,575	0
Small Hydro	368	10	11	11	11	11
Solar PV	147	290	522	794	794	794
Imports	1,502	751	1,051	1,802	1,802	1,802
ISO-NE Total	**8,189**	**5,030**	**6,538**	**9,240**	**12,092**	**5,307**

COSTS OF RENEWABLE RESOURCES

The cost of renewable energy varies across technologies and physical locations. The capital and operation and maintenance (O&M) cost assumptions used in this analysis are shown in Figure 11.

Figure 11
Cost Assumptions for Renewable Technologies

Technology	Installed Cost *(2012$/kW)*	Fixed O&M Cost *(2012$/kW-yr)*	Variable O&M Cost *(2012$/MWh)*
Biomass/Biofuels	$3,954	$103.0	$5.1
Fuel Cells	$7,081	$2.3	$35.9
Landfill Gas	$8,433	$382.9	$8.5
Onshore Wind	$2,498	$28.8	$0.0
Offshore Wind	$5,508	$159.8	$0.0
Small Hydro	$3,151	$13.8	$0.0
Solar PV in 2011	$6,000	$42	$0.0
Solar PV assumed for 2015	$4,887	$42	$0.0

Sources and Notes:

[1] Cost assumptions for biomass, landfill gas, onshore wind, and small hydro are from the Energy Information Administration, Annual Energy Outlook Energy 2010. Adjusted by inflation to convert from 2009$ to 2012. Assumed overnight cost as installed cost.

[2] Cost assumptions for offshore wind are from the testimony Dr. Jurgen Weiss and Judy W. Chang in Response to the Petition of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid for approval by the Department of Public Utilities of amended power purchase agreements between National Grid and Cape Wind Associates, LLC., before the Massachusetts Department of Public Utilities, Docket No. 10-54, September 2010. Adjusted by inflation to convert from 2013$ to 2012$.

[3] Installed cost for fuel cells provided by Clean Energy Finance and Investment Authority (CEFIA), 10/11/2011. O&M costs from Navigant study: "Cost of Electricity Generation," June 12, 2007.

[4] $6,000/kW for solar PV reflects current installed costs for residential rooftops. We assumed that the capital costs will decrease by ~5% per year over the next 5–7 years (in real dollar terms). Fixed O&M cost includes the levelized costs associated with the replacement of inverters.

Capital charge rate estimation for renewable technologies are shown in Figure 12, and capacity factor assumptions are summarized in Figure 13 below Unless otherwise noted, the capacity factors in Figure 13 were applied to both Connecticut and the rest of New England.

Figure 12
Capital Charge Estimation Assumptions for Renewable Technologies

Operating Life (Years)	20
Tax Depreciation Schedule	5yr SLD
Debt Rate	7.0%
Equity Rate	15.0%
Debt Fraction	50.0%
Tax Rate	42.5%
Inflation Rate	2.1%
ATWACC	9.5%
ATWACC Real	7.3%
Resulting Capital Charge Rate	**10.8%**

Figure 13
Capacity Factor Assumptions for Renewable Technologies

Technology	Capacity Factor
Biomass/Biofuels	85.0%
Fuel Cells	90.0%
Hydro	48.4%
Landfill Gas	85.0%
Onshore Wind	
Connecticut (Utility-Scale)	27.9%
Connecticut (Behind-The-Meter)	20.0%
Massachusetts	32.0%
Maine	33.2%
New Hampshire	33.4%
Rhodes Island	23.8%
Vermont	34.7%
Offshore Wind	37.0%
Solar PV	13.0%

Source: Capacity factor assumptions for onshore wind and solar PV are based on hourly generation profiles from National Renewable Energy Laboratory, and for other technologies based on "Massachusetts Renewable Energy Potential, Final Report," Prepared for Massachusetts Department of Energy Resources (DOER) and Massachusetts Technology Collaborative (MTC), August 6, 2008.

Class I REC Prices in New England

The REC payments necessary to provide sufficient revenues for investors are estimated by calculating the levelized production cost for each technology and netting out the projected tax credit and the energy and capacity revenues from the ISO-New England market. Figure 14 below summarizes the estimated REC payments for each technology in 2015 (shown in 2012 dollars). As shown, the REC payments needed for on-shore wind resources vary by location, primarily due to differences in capacity factors (which affect levelized costs and market revenues on a per MWh basis). The estimated REC payments for each technology presented in Figure 14 are only an estimates based on market simulation using the Base Case assumptions. Through power market simulations, the resulting REC price estimates vary across resource scenarios and futures, but they are not shown here. While the behind-the-meter solar PV resources are expected to be able to net meter and receive retail rates for the energy they produce, the fixed costs associated with transmission and distribution do not decrease as a result of increasing distributed generation such as solar PVs.

Figure 14
Estimated REC Price Needed for Renewable Resources in New England
(2015 Base Case)

Technology	All-In Levelized Costs before tax credits	Levelized Tax Credit	All-In Levelized Costs after tax credits	Levelized Market Revenues			Estimated REC Price Needed
				Energy	Capacity	TOTAL	
	(2012$/MWh)	*(2012$/MWh)*	*(2012$/MWh)*	*(2012$/MWh)*	*(2012$/MWh)*	*(2012$/MWh)*	***(2012$/MWh)***
	[a]	[b]	[c]=[a]-[b]	[d]	[e]	[f]=[d]+[e]	**[f] = max{[c]-[f],0}**
Biomass/Biofuels	$126.5	$11.8	$114.7	$53.7	$5.2	$58.9	**$55.8**
Fuel Cells	$207.3	$42.1	$165.3	$54.2	$4.9	$59.1	**$106.1**
Landfill Gas	$183.1	$11.8	$171.3	$54.0	$5.2	$59.3	**$112.0**
Onshore Wind							
Connecticut	$122.0	$23.6	$98.4	$54.2	$3.0	$57.3	**$41.1**
Maine	$102.5	$23.6	$78.9	$53.9	$2.5	$56.4	**$22.5**
Massachusetts	$106.2	$23.6	$82.6	$54.1	$2.6	$56.8	**$25.9**
New Hampshire	$101.8	$23.6	$78.2	$53.9	$2.5	$56.5	**$21.7**
Rhode Island	$143.2	$23.6	$119.6	$53.9	$3.6	$57.5	**$62.1**
Vermont	$98.0	$23.6	$74.4	$54.1	$2.4	$56.5	**$17.8**
Offshore Wind	$233.2	$23.6	$209.6	$54.1	$3.1	$57.2	**$152.4**
Small Hydro	$83.3	$11.8	$71.5	$53.2	$9.2	$62.4	**$9.1**
Solar PV							
Utility-Scale	$535.7	$201.0	$334.7	$58.4	$13.7	$72.12	**$262.5**
Behind-The-Meter	$535.7	$201.0	$334.7	$158.4	$0.0	$158.42	**$176.2**

Note: Market revenue offset for "behind-the-meter" solar PV reflect all-in retail rates for residential customers, which includes an adder of $100/MWh to account for estimated charges above the wholesale energy and capacity values.

To estimate the region's Class I REC prices, we analyzed the regional supply and demand balance for each year under each scenario and future, and set the estimated New England market REC price equal to the required REC payment for the marginal technology (*i.e.*, the resource that requires the highest REC price and would likely be developed based on the supply/demand

balance) in the years when the region meets the aggregate RPS. The following assumptions are applied to perform our regional REC price estimation:

- Onshore wind in Northern New England, which accounts for much of the incremental renewable development, is assumed to be the marginal renewable resource for the region, and sets the regional REC market price.
- Resources that are developed with the support of state-level subsidies do not set the REC market prices, even if their required REC payments are higher than those for onshore wind. For example:
  - Solar PV development in Connecticut will be funded by the state's ZREC and residential PV programs.
  - Fuel cells development in Connecticut will be supported through the state's LREC and Project 150 programs.
  - Cape Wind and Rhode Island offshore wind projects are assumed to be supported by specific long-term contracts with utilities.
- New biomass and landfill gas projects are relatively costly and would demand a relatively high REC payment compared to that of onshore wind. However, due to limited supply of new biomass and landfill gas-fired projects, we do not assume that they would set the regional REC price.

For years when the aggregate regional RPS demand is not met, Connecticut utilities would pay the Connecticut's ACP. Load serving entities outside of Connecticut would pay the lower of the regional market REC price or the applicable state's ACP. Figure 15 below summarizes REC price estimates paid by Connecticut utilities for the Base Case and alternative scenarios across different futures.[9] In the case of High Gas Price future, we estimate that the energy and capacity prices would be high enough that no additional REC payments would be necessary for the marginal wind resource to enter into the market. However, in reality, the short-term REC markets under such a high gas price future may still trade at prices above zero.

Figure 15
Summary of Class I REC Price Estimates in New England

Renewable Resource Scenarios	**Futures**				
	Base *(2012 $/MWh)*	Tight *(2012 $/MWh)*	Abundant *(2012 $/MWh)*	HiGas *(2012 $/MWh)*	LoGas *(2012 $/MWh)*
Base Case - 2015	$22.5	$19.7	$25.7	$7.0	$33.5
Base Case - 2017	$23.0	$50.0	$26.7	$7.0	$50.0
Base Case - 2022	$45.4	$45.4	$45.4	$45.4	$45.4
Full Renewables - 2022	$17.5	$19.2	$20.7	$0.0	$33.1
Low Renewables - 2022	$62.9	$62.9	$45.4	$45.4	$62.9

Note: The highlighted prices are set by the Connecticut's ACP (light) and the regional ACP (dark). Note that Connecticut's ACP does not increase with inflation, therefore the price decreases when shown in 2012 dollars.

[9] The estimated Class I REC prices for all of the scenarios and futures are provided in Appendix A.

Based on the results shown in Figure 15, below are some observations:

- **Base Case:** Connecticut pays the market Class I REC price set by onshore wind through 2017. Given that Connecticut has the lowest ACP price in New England, for years beyond 2017, Connecticut utilities will likely pay ACP for a portion of its Class I RPS obligations and the regional Class I REC price will reach close to the Connecticut's ACP, at $45/MWh (in 2012 dollars).
- **Full Renewables:** The region builds enough resources to meet the region's Class I requirement. Connecticut utilities pay the market REC price set by onshore wind resources.
- **Low Renewables:** The region is significantly short of Class I renewable resources and Connecticut utilities pay the ACP after 2015. The regional Class I REC price by 2022 will reach close to the regional ACP, at $63/MWh, therefore, Connecticut will likely pay the Connecticut ACP of $45/MWh (in 2012 dollars) instead of for RECs for projects located outside of the state.

Class II REC Prices in Connecticut

Pursuant to Conn. Gen. Stat. §16-1(a)(27) Class II renewable energy sources include energy derived from:

- resource recovery facilities;
- a biomass facility that began operation before July 1, 1998, provided the average emission rate for such facility not exceeding 0.2 pounds of NOx per million BTU of heat input for the previous calendar quarter; or
- a run-of-the-river hydropower generating facility up to five megawatts that began operation prior to July 1, 2003.

As of 2008, the latest compliance period for the RPS, approximately 15% of RECs used in compliance for Class II were produced from generators located in Connecticut.

Class II Generator Location	Percentage of Class II REC Compliance Generated
Connecticut	15.1%
Maine	19.4%
Massachusetts	19.3%
New Hampshire	11.3%
Rhode Island	0.2%
Vermont	34.7%

Source: Connecticut DPUC, Docket No. 09-10-09, p. 16.

Currently, there are 122 generating plants across New England that meet the Connecticut Class II requirement which have a total capacity of 670 MW. The 122 Class II sources include 95 hydropower facilities, 17 resource recovery facilities, and 7 biomass plants. Connecticut has 8 Class II resource recovery generating plants, totaling 156 MW.

If it assumed that the average capacity for Class II generators is 80%, the 670 MW would equate to 4.7 million Connecticut Class II eligible RECs. Conn. Gen. Stat. § 16-245(a) requires that 3% of retail sales in Connecticut to be supplied by Class II energy sources. Given the state's electric demand in 2012, the Class II REC demand could be satisfied by 900,000 RECs. Although the generation from these sources may qualify for RECs in other New England states, this capacity creates the conditions for an over-supply in Connecticut Class II-eligible RECs. Currently, Class II RECs trade in the $0.50/mWh range. DEEP estimates the total cost of Class II RPS compliance at less than $4.5 million in 2012. Continued low prices for Class II RECs appear to generate insufficient revenues for in-state resource recovery facilitiest to remain financially viable

Class III REC Prices in Connecticut

Under the existing Connecticut RPS, the Class III requirement is 4% of load, with a price floor of $10 per Class IIII REC. Figure 16 below shows the Class III requirements and the qualifying Class III RECs between 2007 and 2010. Because the current supply of Class III resources is significantly greater than the existing requirements, the resulting market prices from the most recent auction are all at the price floor of $10/MWh. Going forward, if Class III supply continues to be greater than the demand, we assume that all qualifying Class III resources will receive the floor price of $10/REC.

Figure 16
Summary of Historical Class III Requirement and Qualifying Resource Output

Year	**Class III Supply**			**Class III**
	CHP	C&LM	**TOTAL**	**Demand**
	(MWh)	*(MWh)*	***(MWh)***	***(MWh)***
2007	0	437,854	**437,854**	**338,736**
2008	124,331	783,560	**907,891**	**656,600**
2009	528,219	1,002,482	**1,530,701**	**951,790**
2010	645,978	1,236,626	**1,882,604**	**1,280,838**

Source: Class III supply as reported in NEPOOL Generation Information System (GIS). Class III demand calculated based on existing RPS targets increasing from 1% in 2007 to 4% by 2010.

TRANSMISSION REQUIREMENTS FOR INTEGRATING WIND RESOURCES

While new biomass, landfill gas, and small hydro resources are available in certain areas, the greatest renewable energy potential is from onshore wind. As noted in ISO-New England's 2011 Regional System Plan, "Transmission development would be needed to interconnect the wind resources and to bring the energy to load centers in New England."[10]

- Currently, more than 2,000 MW of onshore wind capacity are in the development phase, most of which are located in Northern New England (~ 70% of total).
- In 2011, New England States Committee on Electricity (NESCOE) issued a request for information (RFI) to identify potential resources to be developed across New England in the near-term:
  - Over 50 renewable generation projects have responded, totaling ~ 4,700 MW of new generation capacity. Onshore wind in Maine represented more than 50% of this capacity.[11]
  - Seven respondents submitted transmission-related information, and five of them described various transmission projects designed to deliver wind energy from Maine to loads elsewhere in New England.
- While we are not certain how much of the regional renewable targets can be met without significant transmission investments, recent ISO-NE studies suggest that the existing transmission system accommodate a few hundred MWs of incremental wind generation that are geographically located near existing transmission infrastructure before major transmission upgrades are needed.
  - New England Wind Integration Study (2010) has analyzed a "partial queue" scenario with 680 MW onshore wind, and 460 MW offshore wind capacity while assuming no new transmission lines to integrate wind.[12]
  - The July 2011 update of the ISO-NE Economic Study suggest that ~ 650 MW of wind capacity can be installed in Maine before its export limit starts to bind and wind deliverability drops below 100%.[13]

Based on the above information, we assume that ISO-NE's system would not need significant transmission upgrades to integrate less than 446 MW of new onshore and 486 MW of new offshore wind generation on the system through 2015 in the Base Case. For years beyond 2015, we assume that the transmission cost associated with accommodating the Base Case renewable build-out to be approximately $3,230 per kW of incremental wind capacity installed (in 2012

[10] ISO-NE 2011 Regional System Plan, October 21, 2011, page 12

[11] "Supplemental Responses to RFI Identify Transmission That Could Facilitate Delivery of Renewable Resources," NESCOE, March 21, 2011.

[12] GE Energy, Final Report: New England Wind Integration Study, prepared for ISO-NE, December 5, 2010, pages 78-79.

[13] ISO-NE 2011 Economic Study Update, July 21, 2011, pages 26-27.

dollars).[14] Figure 17 shows the estimated annual transmission costs for the Base Case and Full Renewables scenarios.

Figure 17
Estimated Transmission Costs Associated with New Wind Installations

Scenario	Incremental Wind Capacity Relative to 2015	Unit Transmission Cost	Total Transmission Cost	Capital Charge Rate	Annualized Transmission Cost	Connecticut's Load Share	Transmission Cost Allocated to Connecticut
	(MW) [a]	*(2012 $/kW)* [b]	*(2012 $m)* [c]=[a]×[b]/1000	*(%)* [d]	*(2012 $m/year)* [e] = [c]×[d]	*(%)* [f]	*(2012 $m/year)* [g] = [e]×[f]
Base Case 2017	237	$3,233	$765	12.5%	$96	24.5%	**$23**
Base Case 2022	817	$3,233	$2,640	12.5%	$330	24.5%	**$81**
Full Renewables 2022							
Base	1,808	$3,233	$5,845	12.5%	$731	24.5%	**$179**
Tight	2,643	$3,233	$8,545	12.5%	$1,068	24.5%	**$262**
Abundant	1,110	$3,233	$3,588	12.5%	$449	24.5%	**$110**
High Gas	1,097	$3,233	$3,547	12.5%	$443	24.5%	**$109**
Low Gas	2,282	$3,233	$7,377	12.5%	$922	24.5%	**$226**

Note that the transmission cost estimates reported are very preliminary. None of the studies cited in the section (including the GE study) performed a comprehensive transmission reliability assessment to determine the "needs" to accommodate new wind resources and associated transmission solutions. ISO-NE is currently undertaking more detailed analysis, and this effort is just starting up.

CUSTOMER COSTS RELATED TO THE DEVELOPMENT OF RENEWABLES

The impact of RPS scenarios (and futures) on customer costs are calculated by adding the REC and ACP payments, the associated incremental transmission costs, and the additional payments needed to support in-state Class I programs (such as Project 150, ZREC, and LREC). A summary of the estimated customer costs are provided below in Figure 18.

[14] New England 2030 Power System Study, February 2010, pages 8, 21. The assumed $3,233 is the midpoint of the estimated transmission cost associated with 2,000 MW of onshore and 2,000 MW of offshore wind build-out case from the ISO-NE's Renewable Scenario Analysis (escalated to 2012 dollars).

Figure 18
Summary of Connecticut's Customer Costs Associated with Renewables
(in 2012 $million per year)

Futures	Resource Scenarios					Change Relative to Base	
	2015	Base 2017	2022	Full Renewables 2022	Low Renewables 2022	Full Renewables 2022	Low Renewables 2022
Base Case							
Class I RECs	$87	$113	$168	$115	$57	-$53	-$111
Class I ACPs	$0	$0	$130	$0	$257	-$130	$127
Class III RECs	$12	$12	$11	$11	$11	$0	$0
Transmission for RPS	$0	$23	$81	$179	$0	$98	-$81
CT Renew. Prog. Net of Mrkt. Revs.	$47	$77	$67	$92	$51	$25	-$16
TOTAL RPS COST	**$147**	**$225**	**$457**	**$397**	**$376**	**-$60**	**-$81**
Tight Supply							
Class I RECs	$82	$205	$90	$140	$57	$50	-$33
Class I ACPs	$0	$62	$240	$0	$288	-$240	$49
Class III RECs	$13	$13	$13	$13	$13	$0	$0
Transmission for RPS	$0	$23	$81	$261	$0	$181	-$81
CT Renew. Prog. Net of Mrkt. Revs.	$48	$55	$67	$90	$51	$24	-$16
TOTAL RPS COST	**$144**	**$358**	**$489**	**$504**	**$409**	**$14**	**-$81**
Abundant Supply							
Class I RECs	$92	$119	$228	$121	$50	-$106	-$178
Class I ACPs	$0	$0	$38	$0	$217	-$38	$178
Class III RECs	$11	$11	$10	$10	$10	$0	$0
Transmission for RPS	$0	$23	$81	$110	$0	$29	-$81
CT Renew. Prog. Net of Mrkt. Revs.	$46	$74	$67	$89	$67	$22	$0
TOTAL RPS COST	**$149**	**$227**	**$424**	**$330**	**$343**	**-$94**	**-$81**
High Gas							
Class I RECs	$24	$31	$231	$0	$53	-$231	-$178
Class I ACPs	$0	$0	$37	$0	$215	-$37	$178
Class III RECs	$11	$11	$10	$10	$10	$0	$0
Transmission for RPS	$0	$23	$81	$108	$0	$28	-$81
CT Renew. Prog. Net of Mrkt. Revs.	$53	$90	$67	$108	$67	$41	$0
TOTAL RPS COST	**$89**	**$155**	**$425**	**$226**	**$345**	**-$199**	**-$81**
Low Gas							
Class I RECs	$138	$220	$126	$232	$57	$106	-$69
Class I ACPs	$0	$41	$192	$0	$277	-$192	$85
Class III RECs	$13	$13	$12	$12	$12	$0	$0
Transmission for RPS	$0	$23	$81	$226	$0	$145	-$81
CT Renew. Prog. Net of Mrkt. Revs.	$43	$55	$67	$78	$51	$11	-$16
TOTAL RPS COST	**$194**	**$352**	**$478**	**$548**	**$397**	**$70**	**-$81**

Notes:

[1] "Transmission for RPS" is calculated based on the incremental wind capacity built after 2015, and assume approximately $3,230 per kW of new wind capacity added. See previous section for the details.

[2] "CT Renew. Prog Net of Mrkt. Revs." reflect the annual payments needed to support in-state Class I programs (Project 150, residential solar PV, ZREC, LREC, and other Class I projects) net of energy, capacity and Class I market revenues.

RENEWABLE ENERGY AND ECONOMIC DEVELOPMENT

One of the important policy drivers for renewable energy development is its potential impact on the economic development of the state. The Connecticut's Department of Economic and Community Development assisted in estimating the potential employment and macroeconomic impacts of the various scenarios, taking into consideration the incremental changes in customer bill and the uses of the ACP payments.

The employment and macroeconomic effects associated with the various scenarios are estimated based on the following assumptions:

- Customers pay for RECs, ACPs, and transmission costs through their electricity bills; these costs increase customers' spending on electricity and thereby reduce their spending on other activities. The indirect effects associated with such reduced spending on other activities are simulated to slightly reduce the downstream employment and economic activities in the state.
- ACP and some of the REC payments go to pay for investments in Connecticut-based renewable projects, such as the installation of solar PVs and manufacturing for fuel cell technology. Those payments can directly and indirectly affect employment levels in the relevant sectors of Connecticut's economy.
- Over the long term, the use of renewable energy can help reduce volatility in customers' electricity costs. While that is a benefit to consumers, we have not quantified those effects in this study.

The details of employment and macroeconomic effects are explained in Appendix I. Figure 19 below shows the incremental impact on employment and macroeconomic activities in Connecticut under each resource scenario.

Figure 19
Incremental Impact on Employment and Macroeconomic Activities
(Relative to Base Case Scenario, for the Base Futures)

	Change in All Jobs (FTEs) *(count)*	Change in State GDP *($m/yr)*	Change in Industry Sales (Output) *($m/yr)*	Change in Net State Revenue *($m/yr)*
Full Renewables				
Solar PV Maintenance and Repair	-480	-$63	-$95	-$3
Fuel Cells Manufacturing	-334	-$39	-$79	-$1
Electricity Cost Related	1,245	$230	$380	$9
Total	**430**	**$128**	**$206**	**$5**
Low Renewables				
Solar PV Maintenance and Repair	468	$62	$93	$3
Fuel Cells Manufacturing	323	$37	$77	$1
Electricity Cost Related	807	$149	$246	$6
Total	**1,598**	**$248**	**$416**	**$10**

ENVIRONMENTAL BENEFITS OF RENEWABLE ENERGY

The development of renewable energy generation is largely driven by concern for the environment. The use of renewable energy can help reduce the overall air pollution resulting from the burning of fossil fuels and thereby reduce adverse environmental impacts.

Figure 20 summarizes the annual CO_2 emissions in Connecticut and New England under each renewable resource scenario, and alternative futures.

Figure 20
Summary of CO_2 Emissions Across Renewable Resource Scenarios and Futures
(in million tons per year)

			Futures		
	Base	Tight	Abundant	HiGas	LoGas
Connecticut					
Base - 2015	7.8	8.7	6.4	8.1	8.4
Base - 2017	8.0	9.2	5.8	8.2	8.4
Base - 2022	8.5	8.8	5.8	8.5	8.3
Full Renewables - 2022	8.2	8.7	5.8	8.4	8.1
Low Renewables - 2022	9.0	9.0	6.2	8.9	8.6
New England					
Base - 2015	36.3	41.5	29.1	33.0	38.5
Base - 2017	37.5	44.1	28.9	33.3	39.4
Base - 2022	40.2	47.5	30.3	34.4	41.1
Full Renewables - 2022	38.8	45.2	30.0	34.1	39.0
Low Renewables - 2022	42.4	49.4	32.2	36.2	43.2

APPENDIX E

ENVIRONMENTAL REGULATIONS POTENTIALLY AFFECTING ELECTRIC GENERATION UNITS IN NEW ENGLAND

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INTRODUCTION

This appendix summarizes the various environmental regulations that may affect electric generating units (EGUs) in New England. For each pollutant or pollution issue, the existing and emerging federal and state regulations are described and analyzed as to whether such regulations are likely to impose specific control requirements or emission allowance obligations on EGUs that should be reflected in the IRP modeling. Aside from the continuation of a modest fee on CO_2 emissions arising from New England states' participation in the Regional Greenhouse Gas Initiative (RGGI), this assessment only finds one proposed rule that should be analyzed in the IRP modeling, namely the new requirements on hazardous air pollutants (HAPs). The final section of this appendix analyzes the implications for the specific EGUs and fuel types of this proposal, which are used as an input to the retrofit/retirement analysis described in the main report of this IRP.

Previous IRPs focused significant attention on projecting emission allowance prices that would affect future EGU operating costs in New England. These included allowance prices for sulfur dioxide and nitrogen oxides, a regional CO_2 emission allowance program, and for potential U.S. nationwide CO_2 cap-and-trade policies to address global climate change issues. However, the energy and environmental policy landscape has changed dramatically over the past several years in the U.S. and New England, profoundly reducing the projected effects of market-based emission allowance policies. For example, EGUs within the New England states are not subject to the provisions of the Cross State Air Pollution Rule, and comprehensive federal CO_2 policies are not currently on the horizon.

Previous IRPs also have addressed the potential for emerging environmental requirements to impose significant and inflexible retrofit requirements that may encourage EGUs to retire rather than to incur substantial capital costs that are not economically justified or recoverable through operating revenues in the market. These analyses were based on judgments regarding what rules might be developed under the applicable statutes or rulemaking proposals that were in very early stages of development. For purposes of this IRP, there are few emerging environmental requirements assumed to induce significant changes in generating capacity. As discussed in more detail below, only the HAP rule is likely to induce some fossil capacity retirements. Potentially significant regulatory actions may result from federal rules governing cooling water intake structures or federal air quality standards for sulfur dioxide. It is not known at this time what steps Connecticut and other Northeast states will take to implement these future requirements, so these issues bear close watching in subsequent IRPs.

SUMMARY OF RELEVANT ENVIRONMENTAL REGULATIONS

The federal Clean Air Act (CAA), which was last amended in 1990, requires EPA to set national ambient air quality standards (NAAQS) for six criteria air pollutants. These pollutants include ozone, sulfur dioxide (SO_2), nitrogen dioxide, particulate matter, lead, and carbon monoxide. Electric Generating Units (EGUs) emit pollutants that cause or contribute to four of these six pollutants: ozone, sulfur dioxide, oxides of nitrogen (NO_x), and particulate matter.

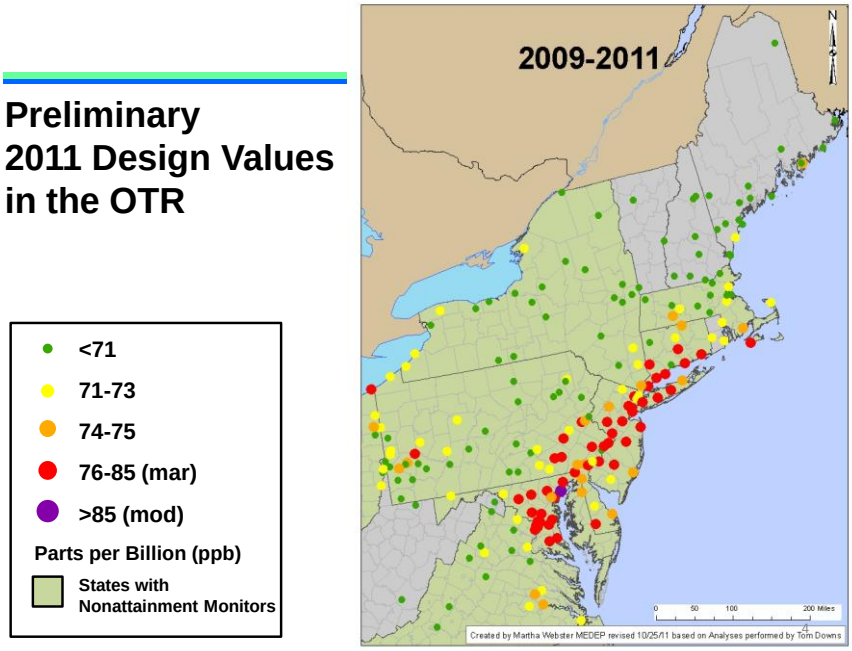
Ozone

Ozone, commonly known as smog, is a secondary air pollutant formed when precursor air pollutants of NO_x and non-methane organic compounds oxidize in the presence of sunlight. Thus smog is a late spring and summer phenomenon in Connecticut and the ISO-NE region. The 1997 ozone NAAQS of 85 parts per billion (ppb) averaged over 8 hours was lowered in 2008 to 75 ppb averaged over 8 hours.[1] EPA expects to issue attainment status designations to states and regions under the 2008 ozone NAAQS by the middle of 2012. Among other factors, designations take into account whether or not monitored air quality in a given area complies with the NAAQS. If air quality does not comply with the standard, then EPA must designate the area as *nonattainment.* There are various degrees of nonattainment which depend on how closely monitored air quality exceeds the NAAQS concentration level. A minor exceedance would result in a designation of *marginal* nonattainment. Progressively more significant designations of *moderate, serious, severe,* or *extreme* nonattainment result from air quality that fails to meet the NAAQS by ever increasing margins.

The CAA establishes requirements that must be implemented along a specified timeframe for each nonattainment classification. In general terms, areas with more impaired air quality must do more work to reduce emissions and meet the standard. Recognizing the increased number of requirements, the CAA also provides additional time to come into compliance — up to 20 years for extreme nonattainment areas. Likewise, if air quality only exceeds the standard by a small margin, the CAA requires less action and imposes a tighter time frame to meet the standard. Thus, if Connecticut and portions of Massachusetts are classified by EPA in mid-2012 as marginal nonattainment for the 2008 8-hour ozone NAAQS of 75 ppb, then these states must take appropriate steps to ensure compliance with the standard within three years (*i.e.*, by the fall of 2015). Figure 1 shows the Ozone Transport Commission (OTC) analyses of air quality monitoring data in the Ozone Transport Region (OTR), an area of 12 states and the District of Columbia along the East Coast that plans compliance strategies to attain ozone standards. Recent modeling by the OTC suggests there are insufficient emissions reductions scheduled to occur in time for marginal and moderate nonattainment areas to meet their projected attainment dates.

[1] Although commonly referred to as an 85 ppb standard (which we adopt in this discussion) the 1997 NAAQS is expressed as 0.8 parts per million (ppm). Under EPA rounding conventions, the actual effective standard was set at 84 ppb.

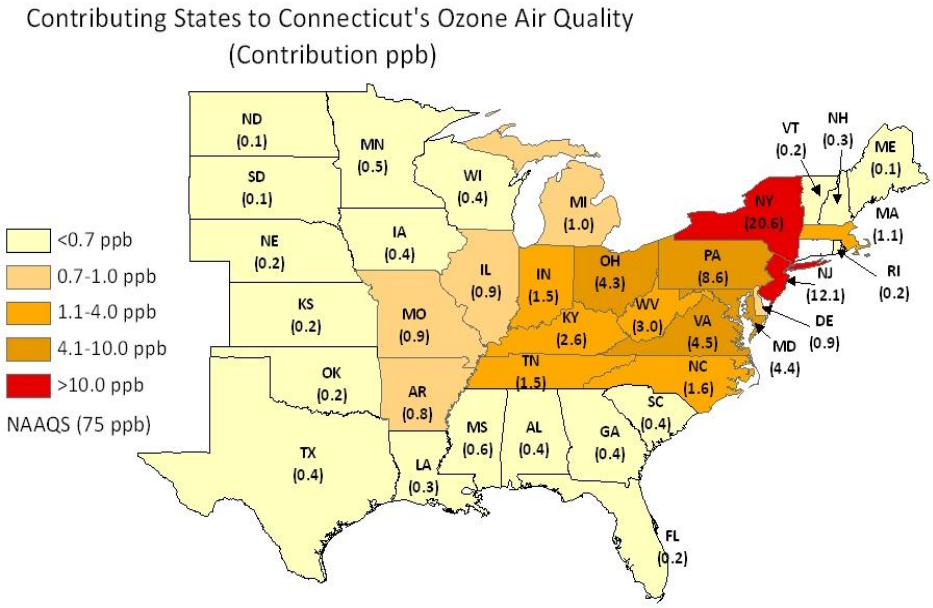
Figure 1
Projected Nonattainment Areas under the 2008 Ozone NAAQS



The CAA also requires EPA to review each NAAQS every five years and to update it if current science indicates that the existing standard does not protect public health with an adequate margin of safety. EPA intends to review the ozone NAAQS in 2013 and has indicated that the best science justifies a more protective standard in the range of 60-70 ppb averaged over an 8-hour period. If EPA adopts a standard in this range, Connecticut and portions of Massachusetts would likely be designated by EPA as moderate or serious nonattainment. These states would then be required to take steps to meet the standard within six to nine years (*i.e.*, by 2021 or 2024 depending on the severity of the classification). These steps would likely include significant EGU NO_x emissions reductions towards the latter years of the IRP planning horizon.

Ozone formation in the Northeast is heavily influenced by emissions from upwind sources. Figure 2 shows ozone contributions to Connecticut from upwind states. Emissions from New York, New Jersey, and Pennsylvania contribute over half of the ozone concentrations (about 41 ppb) of the 75 ppb standard. These states are home to large NO_x sources that have cost-effective opportunities to reduce emissions. The contribution of upwind states to downwind air quality has led to ongoing regional discussions and policy approaches seeking additional emission controls to ensure upwind states comply with the good neighbor provisions of the CAA. The most recent EPA effort to address interstate ozone pollution, the Cross State Air Pollution Rule, is intended to bring about compliance with the 1997 ozone NAAQS 8-hour of 85 ppb but will be insufficient for states to meet the more stringent 2008 8-hour ozone NAAQS of 75 ppb.

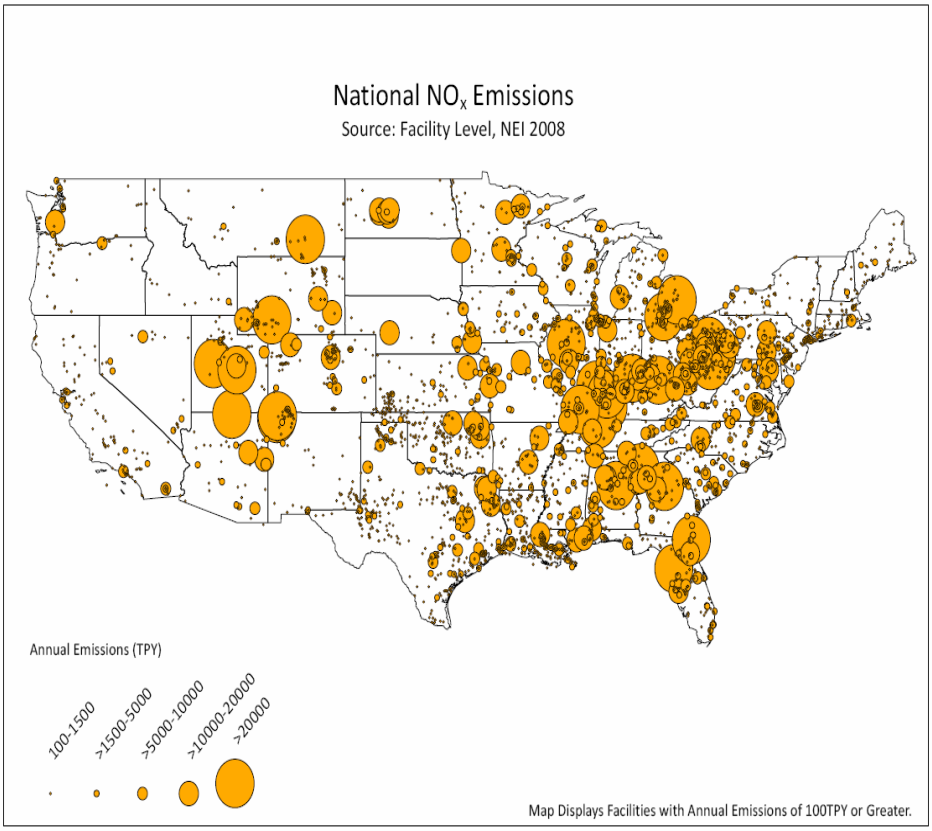
Figure 2
States Contributing to CT 75 ppb Ozone Levels



Oxides of Nitrogen (NOx)

NO_x is a class of pollutant consisting of numerous nitrogen oxide species. One of these species, NO_2, is a criteria pollutant with identifiable health impacts. The primary concern surrounding NO_x arises because of its role as a precursor to the formation of ground-level ozone (*i.e.*, smog). Along with Northeast states, Connecticut has been working to address NO_x emissions from EGUs and other large sources for over 30 years. As a result, emissions from sources in Connecticut and in the Northeast have decreased significantly over time and now are much lower than in other parts of the country. Complicating Connecticut's clean air efforts, significant levels of NO_x emissions from the Midwest and Mid-Atlantic states are transported hundreds of miles on prevailing winds into Connecticut, where they contribute to ozone levels that exceed the NAAQS, as discussed above. The scale and location of NOx emissions from large stationary source throughout the U.S. are shown below in Figure 3.

Figure 3
NO_x Emissions Sources



Federal NO_x Regulations

EGUs have been subject to federal rules limiting NOx emissions for decades, initially through New Source Performance Standards (NSPS) that apply to new units, and some restrictions imposed at the state level to help attain NO_2 and ozone standards. In the early 1990's, the CAA also required NO_x emission limits on existing EGUs to address the problem of acid deposition. Despite these federal efforts, ozone levels in the eastern U.S. remained high and ozone transport concerns (*i.e.*, Midwestern emissions contributing to smog in the Eastern U.S) motivated proposals in the late 1990s to adopt a regional approach to reduce NO_x emissions from existing EGUs in the Eastern part of the U.S. The Ozone Transport Region adopted a NO_x emission allowance trading system in the late 1990s for large sources located on the East Coast, with caps that applied to the five-month "ozone season" (May through September).

The federal NO_x Budget Program successfully built upon this seasonal framework by limiting NO_x emissions over a 20-state area beginning in 2003. EPA subsequently expanded federal NO_x requirements with the promulgation of the Clean Air Interstate Rule (CAIR) in 2005, which lowered the ozone season emission caps, added an annual emission cap and trade component beginning in 2009, and expanded the geographic scope of the program to 28 states and the District of Columbia. EGUs in Connecticut and Massachusetts were subject to CAIR ozone

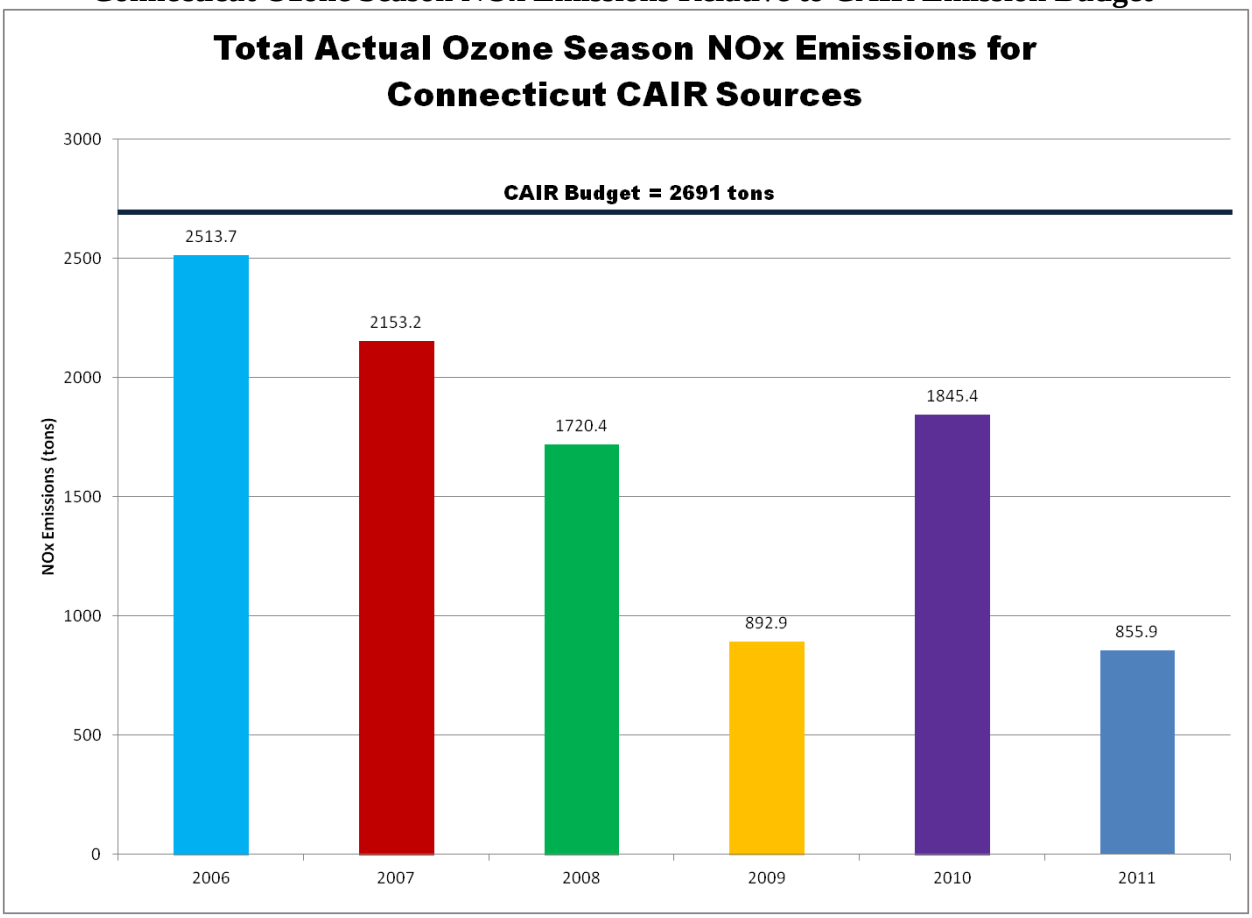
season NO_x requirements, but in 2008 a Federal Court vacated CAIR and remanded the rule to EPA on the basis that it did not conform to certain CAA requirements. The Federal Court authorized CAIR to continue while EPA proposed, analyzed, and finalized a new approach, the Cross State Air Pollution Rule (CSAPR), which was stayed by the D.C. Circuit Court of Appeals on December 30, 2011 (it was scheduled to go into effect on January 1, 2012). While EGUs in Connecticut and Massachusetts were subject to CAIR, these EGUs are *not* subject to CSAPR because emissions from EGUs located in Connecticut and Massachusetts no longer significantly contribute to ozone pollution (with respect to the 1997 8-hour standard) in other states.

State NOx Regulations

Although sources of NO_x in Connecticut will not be subject to CSAPR, Connecticut has relied on the emission reductions associated with CAIR in the State Implementation Plans (SIPs) filed with EPA directed at attaining the 1997 8-hour ozone standard and meeting Regional Haze program requirements. Because of these federally enforceable and pre-existing commitments, Connecticut must take steps to maintain the NO_x emissions reductions associated with CAIR. As such, the State plans to adopt the former CAIR NO_x emission budget as a state-specific emission cap.[2] The proposed NO_x cap is identical to the CAIR ozone season budget for Connecticut (2,691 tons), and the state will implement this cap by allowing emission trading among sources located within the State. This program is unlikely to have any material effect on Connecticut EGUs because their recent emissions levels have remained well below the CAIR budget cap, as shown in Figure 4, as a result of earlier compliance related investment decisions. During 2011, for example, emissions were 70% below the cap, primarily due to a combination of factors: the displacement of coal and oil-fired generation by relatively low-cost natural gas-fired generation; the introduction of new generation and peaking capacity utilizing natural gas along with advanced emission controls; and reductions in peak demand achieved through investments in energy efficiency and demand response (and the effects of the economic recession). Under market conditions analyzed in the IRP, emissions are projected to remain at similarly low levels over the 10-year IRP study horizon, as shown in the IRP report.

[2] Under CAIR, sources within each state were given allowances, the sum of which was considered the state's emission allowance budget. Because sources could buy or sell allowances across the entire 28-state CAIR region, however, the budgets were not strictly caps on a state's emissions (in fact, Connecticut sources were net sellers of allowances, as their overall emissions were below the State budget).

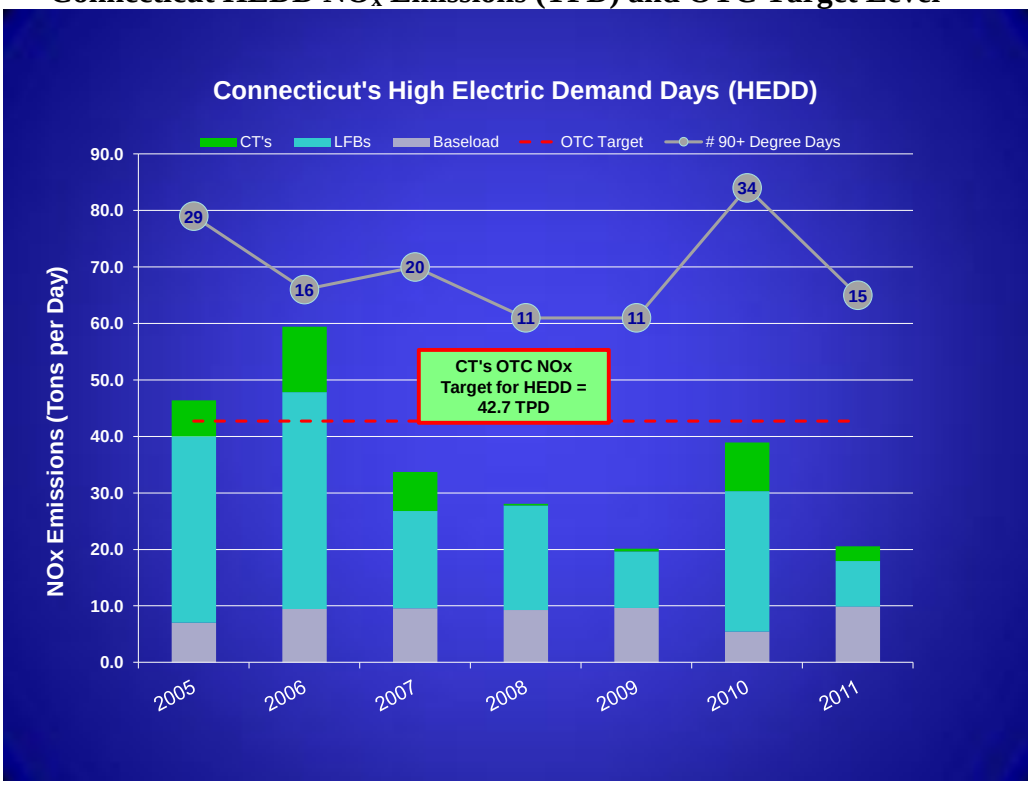
Figure 4
Connecticut Ozone Season NOx Emissions Relative to CAIR Emission Budget



Notes: Connecticut CAIR Sources are EGUs located in Connecticut with nameplate capacity greater than 15MW and industrial boilers located in Connecticut with heat input greater than 250MMBtu.

Connecticut continues to monitor NO_x emissions from peaking units used to meet electric demand on hot summer days when air quality is impaired. These "High Electric Demand Days" (HEDD) are of particular concern because surging air conditioning loads increase the need to dispatch peaking units with historically high NO_x emissions rates during ambient atmospheric conditions ideal for ozone formation. Connecticut has committed to the OTC to limit Connecticut HEDD NOx emissions to below a target level of 42.7 tons per day (TPD), while the average HEDD emissions between 2007 and 2010 were roughly 30 TPD, as shown on Figure 5.

Figure 5
Connecticut HEDD NO_x Emissions (TPD) and OTC Target Level



Notes: These data were derived from the average of the four highest demand days in each year. LFBs are load following boilers and CTs are combustion turbines.

Modeling the Impacts of NO_x Allowance Prices on New England EGUs

Because New England is exempt from CSAPR and ozone season EGU emissions in Connecticut remain below the cap derived from the CAIR allowance budget, both ozone season and annual allowance prices were assumed to be zero for all EGUs.[3] Therefore, the IRP modeling does not include any policy mechanisms for additional NO_x controls, and generating units are assumed to emit NO_x at their current rates.

Sulfur Dioxide (SO_2)

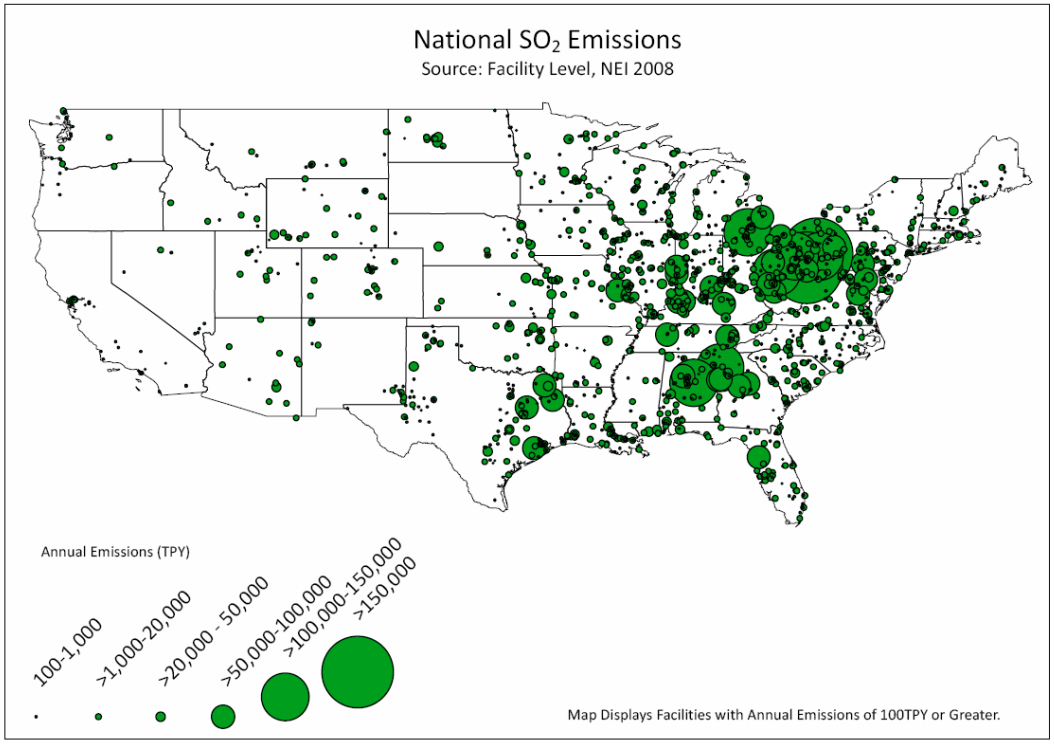
SO_2 emissions are a concern as both a criteria pollutant and because SO_2 is a precursor pollutant to the secondary formation of fine particulate matter, defined under the CAA as particles smaller than 2.5 microns ($PM_{2.5}$).[4] Coal-fired EGUs are the predominant source of nationwide SO_2

[3] Although the ultimate resolution of the CSAPR stay is not known at this time, we assume that the eventual program will exclude Connecticut and Massachusetts.

[4] There is also a 24-hour NAAQS for $PM_{2.5}$, under which Fairfield and New Haven Counties were designated non-attainment areas in 2009 (the only non-attainment areas in New England). However, most

emissions, and similar to NO_x emissions, originate primarily in the Midwest and Southeast regions of the U.S., as shown on Figure 6. Although New England has relatively low SO_2 emissions, SO_2 emissions from upwind states contribute to PM levels and regional haze in New England, and interfere with progress on addressing fine particulate and visibility standards.

Figure 6
SO_2 Emissions Sources



Federal SO_2 Regulations

Title IV of the CAA established a nation-wide SO_2 allowance cap and trade system, designed to combat acid deposition that significantly damaged water bodies throughout the Northeast. While the acid deposition program remains in effect, the emission reductions attributed to CAIR and those expected under CSAPR will likely exceed the reduction requirements associated with the acid deposition program. This has reduced the economic value of Title IV allowances to the point they have no impact on EGU operations.

EGUs in Connecticut and Massachusetts were not subject to the SO_2 provisions of CAIR, and they are not subject to the SO_2 provisions within CSAPR because they do not significantly contribute to particulate pollution in other states. Thus, EGUs in New England would not be

of the $PM_{2.5}$ problem originates from the New York City metropolitan area, and attainment strategies do not affect EGUs in New England.

affected by the CSAPR program, nor would EGUs likely be affected by any subsequent program that emerges from the CSAPR litigation. EPA is, however, evaluating states' SO_2 emissions and atmospheric concentrations to determine attainment status with the 1-hour SO_2 NAAQS, which was updated in 2010. The attainment status designation in Connecticut and in the ISO-NE region depends on the results of an ongoing hybrid modeling and monitoring process that is expected to be completed in mid-2012. The impacts of the designations could range from minor (*e.g.*, permit modifications to limit operating hours) to significant (*e.g.*, required SO_2 controls, operational limits, or fuel sulfur limits). Any necessary restrictions will need to be in place by 2017 to provide for timely NAAQS compliance.

State SO_2 Regulations

Connecticut continues to implement state-specific SO_2 requirements on EGUs pursuant to Section 22a-174-19a of the Regulations of Connecticut State Agencies. In addition, Connecticut is working on the implementation of the new 1-hour SO_2 NAAQS by modeling emissions from all large sources of SO_2 in accordance with applicable EPA guidance. Connecticut plans to complete its modeling by mid-2012, and must file a plan with EPA by June 2013 demonstrating that sources in Connecticut comply with the NAAQS. It is unknown at this time how the implementation of the 1-hour SO_2 NAAQS in Connecticut may impact EGU operation. Due to the relatively short averaging period of the standard coupled with the high hourly rates of allowable SO_2 emissions, the potential impact of the 1-hour SO_2 NAAQS on EGU operation in Connecticut could be significant and bears closer watching for subsequent IRPs.

Modeling the Impacts of SO_2 Allowance Prices on New England EGUs

Because New England is exempt from CSAPR, and CAA Title IV allowances are assumed to have near-zero cost due to emission reductions associated with other programs, SO_2 allowance prices were assumed to be zero for all EGUs. Therefore, the IRP modeling does not include any policy mechanisms for additional SO_2 controls, and generating units are assumed to emit SO_2 at their current rates.

Carbon Dioxide (CO_2)

The prospects of Congress enacting comprehensive national greenhouse gas policy in the near term are very limited. Nonetheless, EPA remains committed to reducing greenhouse gas (GHG, chiefly CO_2) emissions that contribute to global climate change and supports efforts by states to do the same. The timing and scope of EPA action, although limited by judicial consent decrees, remains uncertain.

Federal CO_2 Regulations

On December 23, 2010, EPA entered into a proposed settlement agreement to issue final rules by May 26, 2012 to address greenhouse gas emissions from new and existing fossil fuel-fired power plants, under its existing NSPS authority found in CAA Sections 111(b) and (d). Under this authority EPA has indicated that it intends to issue NSPS (for new sources) and Emissions Guidelines (for existing sources) regarding greenhouse gases (GHGs) from EGUs. EPA recently

announced that it would delay the promulgation of proposed standards and did not further clarify the timing or likely content of the proposed rules.

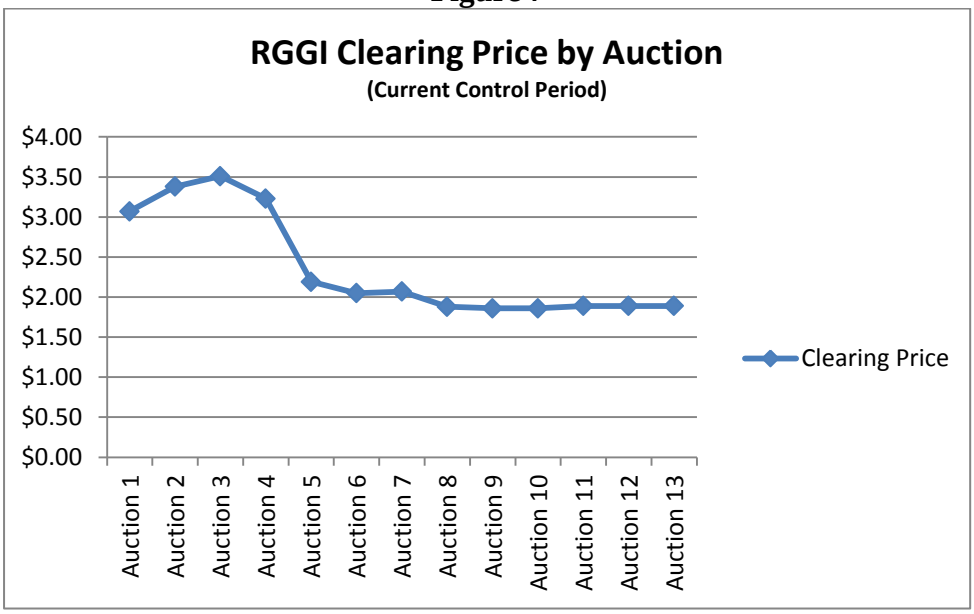
State CO_2 Regulations

Connecticut continues to implement the Regional Greenhouse Gas Initiative (RGGI), the first multi-state cap and invest program where CO_2 allowances are auctioned to an open market, rather than allocated to regulated sources at no cost. The auction proceeds are intended for investments in clean energy and energy efficiency which help to minimize the cost impacts on electricity. The states adopted rules to implement RGGI in 2008, and the program is set to expire in 2019, unless it is extended. Under the RGGI Memorandum of Understanding (MOU), the program is undergoing a review scheduled for completion in 2012, and any changes resulting from program review will be subject to implementing statutory and/or regulatory changes within each participating state in the 2013-2015 timeframe. Because emissions in the current RGGI states are well below the program cap, allowance prices in annual auctions, see Figure 7, and subsequent trades have remained at the price floor (currently $1.90) for most of the program's operation.

Modeling the Impacts of CO_2 Allowance Prices on New England EGUs

The current RGGI floor price of $1.90 per ton was assumed to apply over the entire 10-year horizon for EGUs located in participating states. Although the RGGI program is scheduled to conclude in 2019, for modeling purposes the program is assumed to continue with the current floor prices after that date. It is possible that the 2012 program review will result in a modest tightening of the RGGI emission cap in 2014, but the impact on allowance prices may be muted if sources have banked sufficient allowances in the interim. No additional CO_2 prices were added in the latter years, reflecting the current consensus that comprehensive, national CO_2 allowance or fee systems are unlikely to be enacted in the coming years.

Figure 7



Water Quality Regulations

EGUs that use steam turbines require a significant amount of water in the condensing cycle, and are subject to regulations designed to minimize impacts on surface water quality and aquatic organisms. Water quality impacts range from thermal discharges, discharge of effluents containing pollutants and damage to aquatic life as a result of interaction with water intake structures. EPA and the states, using authority found in the Clean Water Act (CWA), issue and periodically renew permits under the National Pollutant Discharge Elimination System (NPDES) that require sources to employ technologies to reduce impact on surface water resources.

EPA is considering rules that could impact cooling water intake requirements at EGUs operating in Connecticut that have or require a NPDES permit, withdraw more than 2 million gallons per day (MGD) of water from sources protected by the CWA and use at least 25% of that water exclusively for cooling purposes.[5] The timing of these requirements is such that they may impact EGUs towards the end of the IRP planning horizon in 2017/2018.

Federal Water Regulations

EPA is considering rules that could impact cooling water intake requirements at EGUs operating in Connecticut that have or require a NPDES permit, withdraw more than 2 million gallons per day (MGD) of water from sources protected by the CWA, and use at least 25% of that water exclusively for cooling purposes. Specifically, EPA has proposed new regulations under §316(b) of the Clean Water Act to require the location, design, construction, and capacity of cooling water intake structures reflect the Best Technology Available (BTA) for minimizing adverse environmental impact. Cooling water intake structures can harm aquatic life via impingement (organisms trapped against intake screens) and entrainment (organisms passing through the screens and entering the plants' cooling water system). The objective of the proposed §316(b) rule is to reduce fish mortality from either cause.

For new units, the EPA is proposing closed-cycle cooling. For existing units, EPA is considering technology-based compliance option for cooling water intake structures from a menu of pre-approved technologies to enhance survival of all life stages of fish and shellfish impinged on intake screens. Pursuant to judicial consent decree, EPA is required to issue a final rule by July 27, 2012.

State Water Regulations

Connecticut implements federal and state water requirements through state-issued NPDES permits on a case-by-case basis, using best professional judgment to determine the source-specific requirements, and the compliance schedule for meeting those requirements. When EPA finalizes the Section 316(b) rule in 2012, any new requirements will likely begin to be

[5] Affected sources according to 76 FR 22174

implemented through the NPDES permit process within two years after issuance of final federal rules.

Therefore, compliance will be staged and occur over an extended period of time. The proposed requirements for impingement mortality (IM) may be met through several means, but the availability of such options and their costs are very site-specific. For entrainment mortality (EM) the preferred option under the proposed rule for cooling water intake structures gives states substantial discretion to fashion source-by-source requirements for existing EGUs.

Impacts of CWA Section 316(b) Rules on New England EGUs

EPA will not finalize the rule until July 2012, and subsequent implementation will occur as NPDES permits are modified, or are renewed, on a 5-year timetable for each EGU.

The North American Electric Reliability Council (NERC) recently issued the 2011 Long-Term Reliability Assessment (LTRA) which contained an analysis of the impact of impending environmental controls on capacity shutdowns across the country. In that analysis, NERC found that the vast bulk of retirements would be due to the CWA Section 316(b) rules, and in New England specifically these rules would effectively cause the entire oil/gas steam fleet to retire by 2018, imperiling reserve margins in ISO-NE. This analysis appears to take a conservative view of the technology options allowed by the proposed rule and the degree of discretion that states might exercise in applying the requirements.

Another important consideration that may influence decisions regarding the future operation of EGUs in New England is the environmental impacts associated with thermal discharges pursuant to the requirements of CWA Section 316(a). This section requires the thermal component of any discharge be regulated in a manner that will assure the protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife in and on the body of water into which the discharge is to be made. The control measures that may be needed to minimize the adverse environmental impacts of cooling water intake structures may also need to be considered in conjunction with measures that may be needed to control the thermal component of a discharge.

It is difficult at this time to predict how the final rule might differ from the proposed rule, and how states will approach implementation. Lacking precise data on potential EGU-specific costs, the potential impacts of CWA rules concerning water intake structures and thermal discharges were not modeled as part of this IRP. These requirements do bear monitoring and should be included in subsequent IRPs.

Hazardous Air Pollutants (HAPs)

Toxic air pollutants from coal and oil-fired power plants cause serious health and environmental impacts. EPA is under a court order to finalize rules to reduce mercury and other heavy metals such as arsenic, chromium, and nickel, as well as acid gases, from coal and oil-fired EGUs. The timing of these rules is uncertain and when they are finalized will likely drive the installation of additional particulate controls on affected units.

Federal HAP Regulations

EPA proposed the Mercury and Air Toxics Standards (MATS) for power plants on May 3, 2011. The rule would limit mercury, acid gases, and other toxic pollution from power plants, keeping 91% of the mercury in coal from being released to the air. This rule is intended to replace the court-vacated Clean Air Mercury Rule (CAMR). EPA issued a final rule on December 21, 2011. Under the statute authorizing the rule (Section 112 of the CAA, titled National Emission Standards for Hazardous Air Pollutants or NESHAP), affected units have 3 years to comply by installing Maximum Achievable Control Technology (MACT) that is defined in the CAA as an emission rate achieved by the lowest-emitting 12% of comparable units. These requirements on emissions of metals, acid gases, and Particulate Matter (PM) will likely drive extensive emissions controls on oil and coal-fired EGUs without technologies such as activated carbon injection (ACI) and equipment to reduce acid gases coupled with state-of-the-art particulate (PM) controls on coal, and upgraded PM and acid gas controls on oil units.

State HAP Regulations

Connecticut continues to implement state-specific HAP requirements on EGUs pursuant to Section 22a-174-29 of the Regulations of Connecticut State Agencies and pursuant to Section 22a-198 of the Connecticut General Statutes. The latter statute established state-level mercury (Hg) standards for coal-fired EGUs, namely Bridgeport Harbor Unit 3 (BH3) and AES Thames. On July 1, 2008, BH3 and AES Thames were subject to standard of 0.6 pounds Hg per trillion Btu or 90% reduction of Hg from measured inlet conditions. These units will likely face an additional requirement for implementation of Hg continuous emissions monitoring systems (CEMS) based on the Commissioner finding that CEMS for Hg in flue gases are commercially available and can perform in accordance with National Institute of Standards and Technology (NIST) or other EPA-approved methodology. Mercury CEMS are projected to cost $150,000 to $300,000 per facility.

Modeling the Impacts of MATS on New England EGUs

Given the nature of the NESHAPS/MACT requirements, and the current status of pollution control equipment across the New England fossil generating fleet, New England EGUs will be required to add additional controls or else retire capacity. The MATS rule covers all U.S. oil-fired and coal-fired steam power plants and will come into force in 2014/15.[6] The control requirements could induce some EGUs to retire rather than incur significant retrofit costs.

For oil-fired units (see Figure 8), the MATS rule imposes emissions limits for total metals, hydrogen chloride (HCl), and hydrogen fluoride (HF). For the purposes of the IRP modeling, the MATS compliance strategy for oil-fired units is a combination of fuel monitoring for metals and control with an electrostatic precipitator (ESP).

[6] The exact date that most generators will be required to comply with the MATS rule has some flexibility. The final rule gives generators three years to comply, but encourages state permitting authorities to grant an additional year extension for compliance if needed to install controls.

As an upper-bound assumption in the IRP modeling system, all oil-fired units larger than 25 MW are assumed to need an electrostatic precipitator (ESP) as well as fuel monitoring to comply with the MATS rule. No units can avoid the ESP expense by fuel switching, except potentially through cost-prohibitive investments in gas infrastructure. ESP retrofit costs were estimated based on EPA documentation, and vary based on unit size.

Figure 8
Unit-Level Retrofit & Cost Requirements, Oil-Fired Units

Unit Information			HAP Control Strategy			Additional Controls Costs in 2015			Notes on Needed Controls
Name	2011 CELT Summer Capacity *(MW)*	State	Existing Controls	Announced Controls and Retirements	Additional Assumed Controls	Capital Cost *(2012$/kW)*	Incremental FOM *(2012$/kW)*	Incremental VOM *(2012$/kW)*	
BRAYTON PT 4	435.0	MA	ESP			-	-	-	Existing ESP.
BRIDGEPORT HARBOR 2	130.5	CT	ESP			-	-	-	Existing ESP.
CANAL 1	547.1	MA	ESP+SNCR			-	-	-	Existing ESP.
CANAL 2	545.1	MA	ESP			-	-	-	Existing ESP.
CLEARY 8	25.9	MA				-	-	-	No upgrades are needed, assuming official EPA unit size is < 25 MW.
HOLYOKE 6/CABOT 6	9.2	MA		Retire		-	-	-	Submitted Non-Price Retirement Request on 10/19/2011
HOLYOKE 8/CABOT 8	9.2	MA		Retire		-	-	-	Submitted Non-Price Retirement Request on 10/19/2011
KENDALL STEAM 1 2 3	53.4	MA				-	-	-	No upgrades are required because each of 3 separate units are sized < 25 MW.
MIDDLETOWN 2	117.0	CT	ESP			-	-	-	Existing ESP.
MIDDLETOWN 3	236.0	CT	ESP+SNCR			-	-	-	Existing ESP.
MIDDLETOWN 4	400.0	CT			ESP	$72	-	-	No existing controls - ESP needed.
MONTVILLE 5	81.0	CT	ESP			-	-	-	Existing ESP.
MONTVILLE 6	407.4	CT			ESP	$71	-	-	No existing controls - ESP needed.
MYSTIC 7	577.6	MA	ESP			-	-	-	Existing ESP.
NEW HAVEN HARBOR	447.9	CT	ESP			-	-	-	Existing ESP.
NEWINGTON 1	400.2	NH	ESP			-	-	-	Existing ESP.
NORWALK HARBOR 1	162.0	CT	ESP+SNCR			-	-	-	Existing ESP.
NORWALK HARBOR 2	168.0	CT	ESP+SNCR			-	-	-	Existing ESP.
SALEM HARBOR 4	436.8	MA		Retire		-	-	-	Announced retirement for 6/30/2014.
WEST SPRINGFIELD 3	94.3	MA	ESP			-	-	-	Existing ESP.
YARMOUTH 1	50.7	ME	Cyclone		ESP	$223	-	-	Assume cyclone is insufficient for HAP - ESP needed.
YARMOUTH 2	51.1	ME	Cyclone		ESP	$226	-	-	Assume cyclone is insufficient for HAP - ESP needed.
YARMOUTH 3	115.2	ME	Cyclone		ESP	$113	-	-	Assume cyclone is insufficient for HAP - ESP needed.
YARMOUTH 4	603.2	ME	ESP			-	-	-	Existing ESP.

For coal-fired units (see Figure 9), the MATS rule will enforce emissions limits for mercury, particulate matter (PM) as a surrogate for toxic non-mercury metals, and HCl as a surrogate for all toxic acid gases. For the purposes of the IRP, the MATS compliance strategy for coal-fired units relies on a combination of existing controls and already-announced planned controls when possible.[7] Based on EPA analysis regarding the combination of controls needed for compliance, each coal unit is assumed to need: (1) activated carbon injection (ACI) for mercury control; (2) either a fabric filter (FF or "baghouse") or a cold ESP for mercury and PM control; and (3) either dry flue gas desulfurization (FGD), wet FGD, or dry sorbent injection (DSI) for HCl.[8] For units that do not currently have a cold ESP or baghouse, a baghouse is assumed to be the preferred

[7] Existing and planned controls data from Ventyx (2011), detail on hot and cold ESP from EPA (2011d).

[8] See EPA (2011e), pp. 76-82 regarding mercury and PM controls, and pp. 87-89 regarding HCl controls.

upgrade option consistent with the EPA's analysis.[9] For units without existing or planned wet FGD, dry FGD, or DSI, the preference is assumed to include an upgrade to DSI due to the lower capital costs.[10]

In the IRP modeling system, all coal-fired units larger than 25 MW are assumed to need activated carbon injection (ACI) combined with a fabric filter or cold ESP to control mercury emissions, and wet flue gas desulfurization (FGD), dry FGD, or dry sorbent injection (DSI) to control acid gas emissions. Retrofit costs for these technologies were estimated based on EPA documentation, and vary based on unit size.

Figure 9
Unit-Level Retrofit & Cost Requirements, Coal-Fired Units

Unit Information			HAP Control Strategy			Additional Controls Costs in 2015			Notes on Needed Controls
Name	2011 CELT Summer Capacity *(MW)*	State	Existing Controls	Announced Controls and Retirements	Additional Assumed Controls	Capital Cost *(2012$/kW)*	Incremental FOM *(2012$/kW)*	Incremental VOM *(2012$/kW)*	
AES THAMES	182.7	CT	FF+DSI		Retire	-	-	-	Assume retirement 5/30/2014 given bankruptcy.
MERRIMACK 2	338.4	NH	Cold ESP	Wet FGD (2011)	ACI	$12	$0	$3	Needs ACI, Wet FGD announced for compliance.
BRIDGEPORT HARBOR 3	383.4	CT	ACI+FF		DSI	$52	$1	$7	Needs acid gas control (assume DSI)
BRAYTON PT 1	243.5	MA	ACI+FF+Dry FGD			-	-	-	In compliance.
BRAYTON PT 2	244.0	MA	ACI+FF+Dry FGD			-	-	-	In compliance.
BRAYTON PT 3	612.0	MA	ACI	Dry FGD+FF (2013)		-	-	-	Dry FGD and FF announced for compliance.
MT TOM	142.9	MA	FF+DSI		ACI	$26	$0	$3	Needs ACI.
SALEM HARBOR 1	79.8	MA	Cold ESP	Retire		-	-	-	Announced retirement for 12/31/2011.
SALEM HARBOR 2	78.0	MA	Cold ESP	Retire		-	-	-	Announced retirement for 12/31/2011.
SALEM HARBOR 3	149.8	MA	Cold ESP	Retire		-	-	-	Announced retirement for 6/30/2014.
SOMERSET 6	0.0	MA	Cold ESP		ACI+DSI	$184	$3	$18	Needs ACI. For acid gas, assume DSI.
MEAD	1.6	ME				-	-	-	Assume no upgrades are required due to cogen status.
MERRIMACK 1	112.5	NH	ACI+Cold ESP	Wet FGD (2011)		-	-	-	Wet FGD announced for compliance.
SCHILLER 4	47.5	NH	Cold ESP		ACI+DSI	$189	$3	$18	Needs ACI. For acid gas, assume DSI.
SCHILLER 6	47.9	NH	Cold ESP		ACI+DSI	$189	$3	$18	Needs ACI. For acid gas, assume DSI.

9 See EPA (2011e), pp. 76-82.

10 See EPA (2011e), Table 5-23, EPA (2011f), Table 5-4.

APPENDIX F

NATURAL GAS

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INTRODUCTION

Natural gas is a key fuel for the electric sector in New England. In 2010, over 40% of the region's capacity was primarily gas-fired, and gas accounted for over 45% of the energy generated.[1] Gas-fired generation is on the margin setting the wholesale market price in over 70% of hours, and the effect of gas price on power price is even stronger, explaining about 90% of the variation in power prices.[2] Under any plausible future for the ten-year horizon of this study and beyond, New England's electric sector will continue to rely heavily on natural gas. This dependency on gas is likely to increase in the future, due to the expected retirement of non-gas generation (*i.e.*, coal-fired, oil-fired, or nuclear generation). While gas-fired generation has numerous advantages, including high reliability, relatively low construction cost, and modest environmental impacts, the region's dependence on gas as an electricity fuel also raises some potential concerns, particularly regarding exposure to gas prices, and potential reliability implications regarding fuel delivery to gas generators when the gas system is stressed in the winter heating season.

This appendix examines the natural gas outlook for New England and Connecticut in the medium to long term, focusing on changing national and regional factors affecting natural gas supply, demand, price, and deliverability.

Key Findings

- The overall natural gas supply picture for both the U.S. and New England appears favorable, due particularly to the recent and projected growth of new unconventional domestic gas supplies, such as shale gas, some of which are located much closer to New England than traditional gas supplies. However, these expanding supplies compete with traditional sources to serve New England gas demand using the existing gas pipeline infrastructure.
- Overall gas demand nationwide and in New England is expected to increase over the next decade. Most of the growth will come from increased use of natural gas as a fuel for electric generation, owing to the dominance of gas technologies for new capacity builds and the expectation that a significant (but not yet known) amount of existing coal-fired capacity will retire rather than invest in pollution controls.
- Rapidly expanding domestic supply has led to sharply reduced prices compared to levels experienced only a few years ago, and have reduced expectations of future prices. Compared to the 2010 IRP when the long-term expected price level was around $7/MMBtu (2012 real dollars), current expectations are around $5–6/MMBtu (2012 real dollars), driven largely by greater expected production from new unconventional supply sources. However, it is not certain that these current price expectations will be

[1] Strategic Planning Issues, ISO New England presentation at the NEPOOL Participant's Committee Meeting, March 4, 2011.

[2] ISO 2010 Market Report, p. 61.

fulfilled; a long-term gas price range of approximately $3–$10/MMBtu was examined in this study.

- Gas delivery capacity to New England has increased over the past several years, mostly due to new liquefied natural gas (LNG) capacity. Currently, over 3 billion cubic feet per day (Bcf/d) of gas can be delivered to New England via the interstate pipeline system. The actual system capability may be higher depending on the amount of liquefied natural gas imports received at the four LNG terminals now operating in New England and Eastern Canada.[3] LNG peak-shaving facilities in New England supplement this capability and provide additional supplies on peak days. LNG provides about 20% of total New England annual gas use, with supplies regularly received at the Everett, Massachusetts LNG terminal and the Canaport LNG terminal.
- The composition of flows on the pipelines serving New England has changed recently due to the growth in unconventional domestic supplies (primarily shale gas) displacing traditional supplies such as Canadian pipeline imports. New pipeline expansion activity to increase the takeaway capacity from the Marcellus shale will deliver additional supplies to the pipelines that serve New England. While these expansions alleviate localized bottlenecks in the Marcellus shale, they do not provide incremental delivery capacity to New England. Some proposals to expand pipeline capacity into New England are in the preliminary stages and it is not clear if and/or when they might advance to the construction phase.
- The pipeline system serving New England is essentially fully subscribed, meaning that the pipelines have sold their existing capacity under firm contracts. The largest holders of firm pipeline capacity in New England are the local distribution companies (gas LDCs). Electric generators hold some firm pipeline capacity, but rely mostly on interruptible transportation service.
- The natural gas transportation system serving New England is most heavily utilized during the winter months when the LDCs experience their peak loads to serve the space heating needs of their customers, causing higher delivered gas prices during the peak-demand winter period. Reliance on natural gas-fired generation has increased the stress on the natural gas infrastructure, particularly during peak winter periods, creating concerns about whether winter gas deliverability problems in a severe cold snap might impact electric reliability. The likelihood and electric reliability implications of such situations are explored in Appendix B (Resource Adequacy). The gas delivery system is much less heavily utilized during other seasons, but can experience high utilization during hot summer days when electric generation demand for gas is high.

[3] The amount of imported LNG entering New England is based upon a complex set of factors including world LNG prices, contractual obligations, physical limitations at constraint points and laterals, and local demand and prices.

The remainder of this appendix motivates and explains these findings. An overview of the U.S. natural gas market fundamentals provides context for the projections of commodity prices, while the regional New England overview reflects the regional infrastructure, and supply and demand forces, that make the New England gas market unique. This report has drawn on data and information from a variety of sources, including the Northeast Gas Association, the Energy Information Administration, the interstate pipelines, ISO New England, LNG terminal owners, natural gas and electricity distribution companies serving the region, and publicly available industry analysis and news. Efforts have been made to consider stakeholder input and incorporate numerous views.

NATIONAL NATURAL GAS MARKET OVERVIEW

Recent U.S. Supply/Demand Fundamentals

U.S. natural gas production has seen strong growth in the last 5 years, due mainly to an increase in production from unconventional sources such as shale gas and tight gas. As recently as several years ago, declining conventional gas supplies led to higher prices and expectations that relatively expensive LNG would be needed to fill the gap, leading to the development of a number of new LNG import terminals. In just the few years since then, the advent of new unconventional gas sources, particularly shale gas, has transformed the North American gas market. These new supplies have more than offset the decline in conventional gas supplies, and have begun to displace both Canadian pipeline imports and LNG imports. This trend is expected to continue and accelerate, with shale gas becoming the dominant source of U.S. supply in the future.

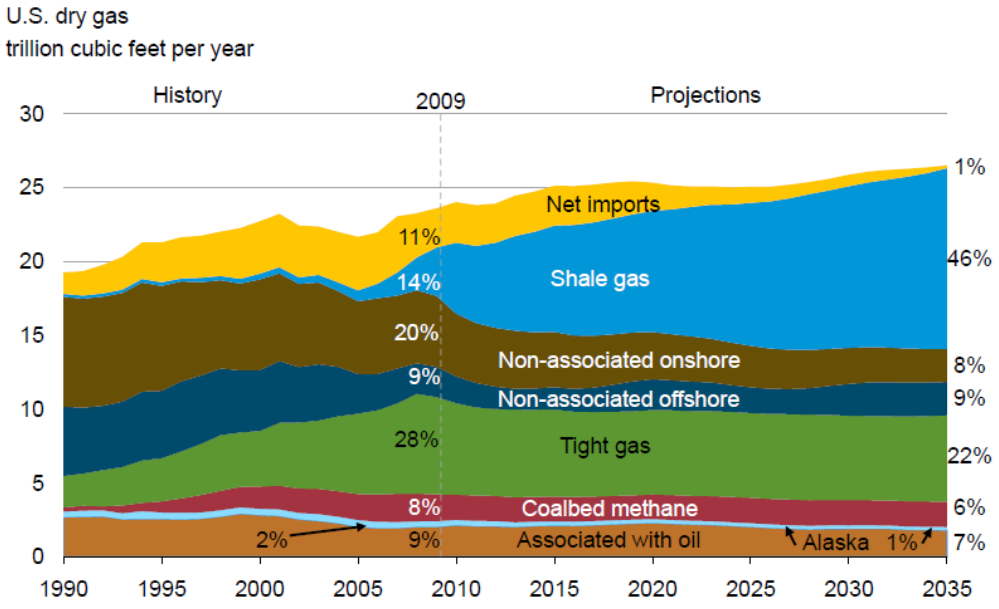
U.S. demand for natural gas was relatively flat last decade, but is now expected to grow in the coming decade and beyond, in part because lower natural gas prices have solidified natural gas as the fuel of choice for electric generation capacity additions. Gas demand for electric generation may also receive a significant boost if substantial coal-fired generation capacity is retired as a result of new environmental regulations. In addition, low natural gas prices may also encourage increases in industrial natural gas use and some residential fuel-switching from oil to natural gas. Factors that may serve to limit growth in natural gas demand include renewables development (which can reduce gas demand in regions where gas-fired generation is at the margin when renewables are producing power), continued or expanded energy efficiency efforts, or increases in long-term natural gas prices.

U.S. Natural Gas Supply Outlook

Technological advances in horizontal drilling and hydraulic fracturing ("hydro-fracking" or "fracking") over the past few years have created the shale gas boom, enabling the economic recovery of large shale gas reserves that had previously been difficult and uneconomic to produce. Shale gas production has increased 5-fold from less than 1 Tcf (2.7 Bcf/d) in 2006 to 5 Tcf (13.7 Bcf/d), so that it now comprises a significant portion of domestic supply (about 20% of

total U.S. gas production).[4] Figure 1 shows that growth in shale gas production is projected to continue, with shale gas becoming the dominant source of domestic gas production in the next decade, eventually supplying up to 12 Tcf (roughly 33 Bcf/d), or nearly half of projected U.S. natural gas demand, by 2035. Increased shale production is projected to displace imports (both pipeline imports from Canada and LNG imports) and offset the decrease in conventional natural gas production. This is particularly encouraging for New England due to its proximity to the Marcellus Shale, which according to Wood Mackenzie, could produce roughly 10 Bcf/d (or 3.65 Tcf) by 2020.[5]

Figure 1
U.S. Supply Portfolio (1990-2035)



Source: EIA *Annual Energy Outlook* 2011

In fact, projections of shale gas production have increased markedly even just in the past two years, which has contributed to a continuing downward trend in long-term price expectations: projections for 2030 shale production were revised upward from roughly 4 Tcf (10 Bcf/d) in 2009 to 11 Tcf (30 Bcf/d) in 2011.[6]

Although shale gas offers ample reasons for optimism about natural gas as a fuel in the coming decades, there are still uncertainties surrounding its ultimate potential. In its 2011 *Annual Energy Outlook*, EIA noted some of the resource production uncertainties, including lack of

4 "Shale Gas and the Outlook for U.S. Natural Gas Markets and Global Gas Resources," presentation by Richard Newell, Administrator to Organization for Economic Cooperation and Development (OECD), July 21, 2011.

5 See "Alberta's Energy Resources: Opportunities and Challenges in a Global Context," presented by Paul Tsounis, Alberta Department of Energy, September 2011, slide 14. In comparison, current annual average gas demand across New England is roughly 2.2 Bcf/d. See "2010 Statistical Guide," Northeast Gas Association, December 2010, p. 3.

6 EIA 2009 and 2011*Annual Energy Outlook*.

reliable data on long-term production profiles and uncertainty in technological advances that could lead to more productive or less costly well drilling and completion.[7]

Other factors add to the uncertainties regarding shale gas and the long-term natural gas outlook. The potential environmental consequences of shale gas extraction (particularly effects on drinking water) have received intense scrutiny. Along with the Federal Environmental Protection Agency (EPA), states such as New York are conducting multi-year studies on environmental impact in order to recommend additional regulations on shale gas development. These recommendations and proposed regulations may constrain access to parts of the shale resource and increase production costs, although most industry observers believe that their overall impacts will be modest and manageable.

As a result of these and other uncertainties with respect to the cost and availability of non-shale resources, the shape of the overall supply curve for natural gas in the U.S. is also quite uncertain. A recent study by MIT captures the uncertainty in the long-run supply curve, but suggests substantial gas resources will be available at breakeven prices between $4/MMBtu and $8/MMBtu (in real 2007 dollars).[8] MIT's supply curves suggest uncertainties that go in both directions, and could lead to a future in which natural gas is even more abundant and less expensive than current expectations, or alternatively that it is less available and more costly.

1. Natural Gas Demand Outlook

While gas demand was quite flat over the course of the last decade, gas demand is projected to increase in the coming decades. A number of factors contribute to this expectation, including the expectation of low gas prices, underlying economic growth; fuel switching from oil due to gas's price advantage; the need to replace generation from potential retirements of coal units; new gas-fired generation additions; and even the potential for LNG exports. Overall, EIA projects growth in U.S. natural gas consumption, from 24.5 Tcf (67 Bcf/d) in 2010 to just over 27.2 Tcf (74 Bcf/d) in 2035, with 2035 gas demand ranging from 25 Tcf (68 Bcf/d) in its low case to 30.4 Tcf (83 Bcf/d) in its high case, as shown in Figure 2.

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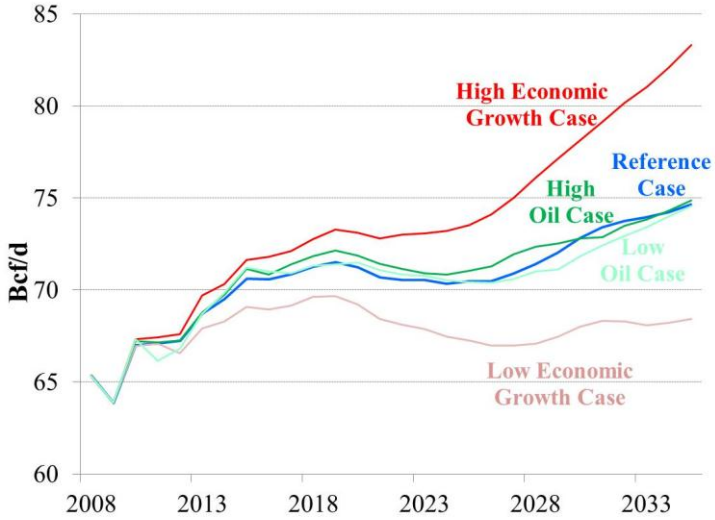
7 EIA 2011 *Annual Energy Outlook*, p. 37.

8 See "The Future of Natural Gas," MIT, June 9, 2011. For example, MIT's low supply case indicates about 600 trillion cubic feet (Tcf) of gas resources at a breakeven gas of $8/MMBtu (2007 dollars), while the high supply case shows about 1,100 Tcf at the same breakeven price (for comparison purposes, the U.S. now consumes approximately 24 Tcf of natural gas per year). At a $4/MMBtu breakeven price, the MIT supply curves show the resource base ranging from about 200 Tcf to roughly 400 Tcf of gas.

Figure 2
Natural Gas Consumption in Various Scenarios



Source: EIA *Annual Energy Outlook* 2011

Proposed new EPA regulations on air quality, water use, and ash disposal are likely to require many existing U.S. coal units to install expensive control equipment, or alternatively to retire. If gas prices remain low as expected, this will keep electricity prices low and add to the pressure on these units to retire. A recent report by The Brattle Group finds that potential coal retirements due to new EPA regulations could increase gas demand by up to 5.8 Bcf/d by 2020 (2.1 Tcf/year or less than 10% of projected use) with significant regional variations; other analysts have reached similar conclusions.[9,10] Although New England does not have large amounts of coal-fired capacity itself and thus faces less in the way of potential coal retirements than some other regions, large scale coal retirements in other regions, and replacement with gas-fired capacity, could affect national gas prices.

Even beyond the potential for replacing retiring coal capacity, low natural gas prices have made gas-fired generation attractive. EIA forecasts that 60% of electricity generation capacity additions between 2010 and 2035 will be gas-fired.[11] Most industry observers agree that electric generation represents the largest growth market for natural gas over the coming decades.

Finally, the increase in oil prices over the past several years has left natural gas with a price advantage that is expected to persist far into the future. Oil prices are three times higher than

[9] "Potential Coal Plant Retirements Under Emerging Environmental Regulations," The Brattle Group, December 8, 2010.

[10] The National Petroleum Council's recent report reviewed various studies on potential coal plant retirements. According to the report, coal retirements resulting from EPA regulations could range from 12 GW to 101 GW (averaging 58 GW across the studies reviewed) and natural gas demand growth could range from 0.4 Tcf (1 Bcf/d) to 4.7 Tcf (13 Bcf/d). See "Prudent Development — Realizing the Potential of North America's Abundant Natural Gas and Oil Reserves," pp. 3-17, September 15, 2011.

[11] *Annual Energy Outlook* 2011, U.S. Energy Information Administration, April 2011, p. 74.

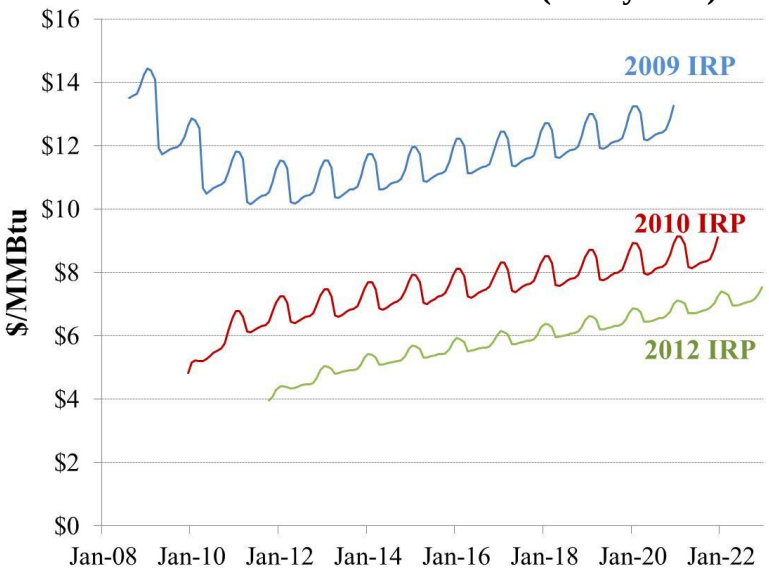
natural gas prices, on an energy basis, and are projected to remain at these higher levels in the future.[12] This long-term price advantage for natural gas is likely to have several effects that contribute to the expected increase in gas demand. The lower price of gas relative to oil will provide incentives for fuel switching for heating use and may lead to increases in industrial gas use. It also creates an incentive to export LNG from the U.S to premium gas markets overseas that are willing to pay higher prices relative to gas prices in North America (especially since international LNG prices are often linked to the higher oil price). Existing LNG terminals, already underutilized at only 5% of capacity so far this year, are now applying for export licenses.[13] For example, Dominion Cove Point, which began operation in the 1970s as an import facility, recently got approval from U.S. Department of Energy to export up to 1 Bcf/d as LNG, and is expected to access gas from the Marcellus Shale.[14]

U.S. Natural Gas Price Outlook

Recent changes in supply and demand fundamentals have had a dramatic impact on the outlook for U.S. gas prices. With lower-cost shale gas production being projected to meet a large share of domestic demand, long-term gas prices have fallen considerably since the 2010 IRP.

Figure 3 shows that NYMEX futures prices for natural gas have decreased dramatically since 2008. With lower-cost shale gas production projected to meet a large share of domestic demand, long-term gas prices have fallen considerably since the 2010 IRP.

Figure 3
NYMEX Futures for Natural Gas (Henry Hub)



Source and Notes: NYMEX data obtained from Bloomberg. NYMEX Henry Hub futures as of

[12] *Id*, p. 78.

[13] "Winter Gas Prices Will Keep Lid on Prices: FERC," Gas Daily, October 21, 2011.

[14] DOE/FE Order No. 3019, FE Docket No. 11-115-LNG, October, 7 2011.

7/1/08 and 11/2/09 were used for the 2009 and 2010 IRP respectively. For 2012 IRP, an average of NYMEX Henry Hub futures over 30 transaction days between 8/5/11 and 9/15/11 was used.

REGIONAL NATURAL GAS MARKET OVERVIEW

Natural Gas Demand in New England

Natural gas is an important source of energy both for Connecticut and New England as a whole providing for roughly 27% of energy use in New England. The residential/commercial and electric sectors are the two largest classes of end users for natural gas in the region, accounting for roughly 87% of total annual natural gas demand in New England (43% for residential/commercial and 44% for power generation). Industrial customers account for the remaining demand. Local gas distribution companies (LDCs) serve mostly residential and commercial customers. Electric generators and large industrial customers are sometimes served by LDCs but often are directly connected to the interstate pipelines.

Natural gas currently makes up about 35% of the residential home-heating market in New England.[15] In Connecticut, this share is slightly lower at roughly 31%, with oil maintaining a much higher 50% market share.[16] However, with natural gas prices expected to remain below oil prices in the future, New England residential customers who currently use oil for heating but are in areas served by gas distribution infrastructure may switch to natural gas. This could contribute to growth in regional natural gas demand, especially during the winter heating season.

The electric sector can also affect gas demand. Currently, natural gas accounts for 45.6% of electricity produced in New England and 41.2% of generating capacity.[17] New England currently has a surplus of generating capacity. While new EPA regulations are expected to cause some retirements of coal and oil-fired generators, the level of retirements is not expected to be so large as to require major new gas-fired generation additions. However, it could increase gas demand from existing generators that would need to operate more frequently. On the other hand, additions of renewable generation to meet RPS might tend to reduce gas demand. There are both positive and negative forces affecting the electric sector's demand for natural gas, and its ultimate gas demand will depend largely on the future capacity mix and utilization.

Seasonality in Gas and Electric Demand

The residential and commercial sector in New England uses natural gas primarily for space heating. Consequently, demand for natural gas by the residential and commercial sector — and for the system as a whole — is greatest during the winter heating season. In contrast, demand for natural gas by electric generators is greatest during the summer months. Although electricity makes up roughly 45% of total annual natural gas demand, peaking in summer, electric demand for gas is spread more evenly, so that the gas system as a whole is still strongly winter peaking. Figure 4 shows the natural gas consumption profile by month and end-use sector. These

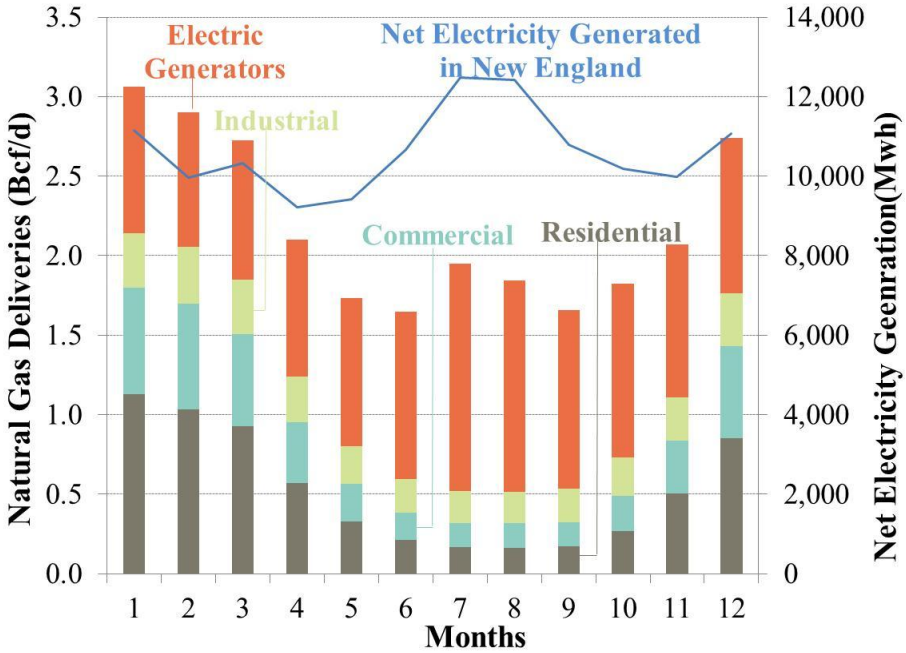
[15] "NGA Issue Brief: Natural Gas Offers Price, Supply, Environmental Advantages for Homes and Businesses," Northeast Gas Association, October 2011.

[16] "2010 Statistical Guide," Northeast Gas Association, December 2010, p. 59.

[17] "Fuel Diversity in New England," Mark Babula, ISO New England, June 29, 2011, slide 4.

seasonal patterns of overall gas demand affect the delivered price of gas, with high regional prices during winter when there is heavy utilization of the regional gas infrastructure.

Figure 4
Natural Gas Consumption Profile by Customer Class
Monthly Averages over Jan 2006 through Aug 2011

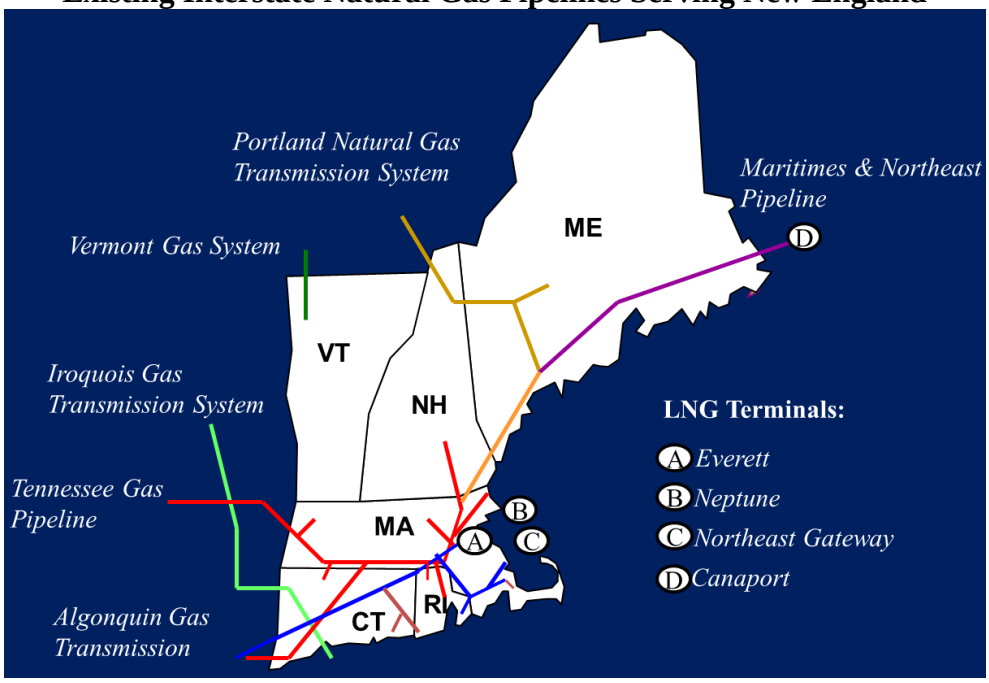


Sources and Notes: EIA; Natural gas deliveries and net electricity generated in New England presented in the above graphs are averages over Jan 2006 through Aug 2011. Missing values were ignored while calculating the average monthly deliveries.

Existing Natural Gas Infrastructure

With no indigenous natural gas production and no underground gas storage in the region, New England relies on deliveries through five major interstate pipelines, supplemented by LNG, to serve natural gas demand in the region. As shown in Figure 5, the pipelines directly serving New England are: Tennessee Gas Pipeline (TGP), Algonquin Gas Transmission (AGT), Iroquois Gas Transmission (Iroquois), Portland Natural Gas Transmission (PNGTS), and Maritimes & Northeast Pipeline (M&N).

Figure 5
Existing Interstate Natural Gas Pipelines Serving New England



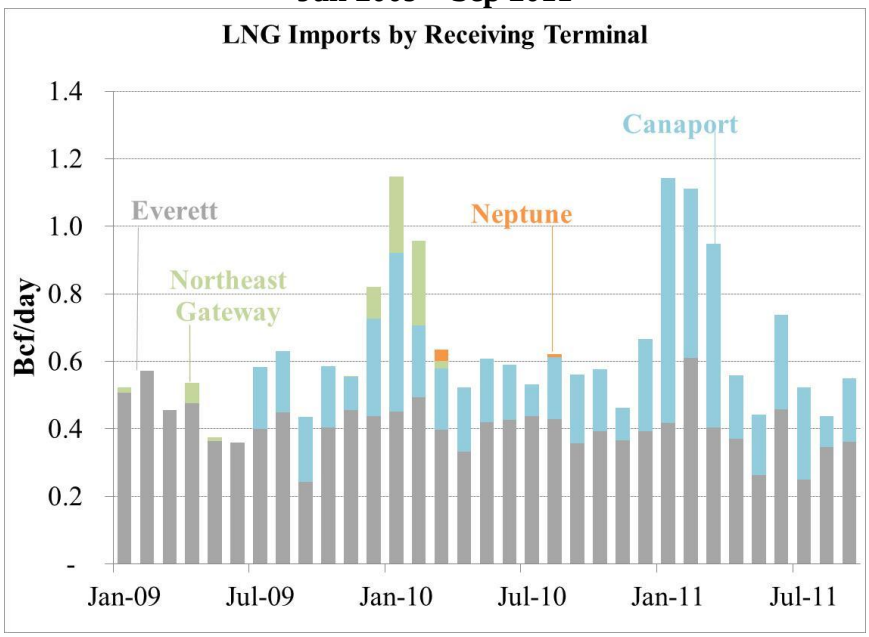
Sources and Notes: Recreated using map from New England Gas Association presentation titled "Will There Be Enough Gas to Fully Support Electricity Generation in New England?" (2/16/2001) and map of LNG terminals available via FERC (as of 11/1/11).

Historically, the AGT and TGP systems have received much of their gas supplies from the Gulf of Mexico, with TGP also receiving significant supplies from Western Canada. In the past few years, the supply mix serving these pipelines has changed significantly with the commencement of the Rockies Express pipeline and production increases in the Marcellus Shale. Both of these pipelines now receive an increasing share of gas from the Rockies and Marcellus supply areas. PNGTS and Iroquois primarily transport Western Canadian gas into the region, and M&N transports Sable Island offshore gas (in addition to LNG from the Canaport LNG terminal).

New England also has the capacity to receive LNG imports from overseas supply sources (transported via ship), which are vaporized and delivered into interstate pipelines. LNG has historically been an important source of supply for New England, particularly during the winter heating season, supplying roughly 20% of New England's total annual gas needs.[18] Currently, there are three LNG terminals operating in New England (Everett, Northeast Gateway, and Neptune) and one in Canada (Canaport). LNG imports to these terminals in the last few years are shown in Figure 6. As can be seen, imports into Everett and Canaport have been substantial in the past and have provided significant supplies to the region throughout the year.

[18] "Regional Market Update," Northeast Gas Association, July 2011, p. 5

Figure 6
Monthly Imports by LNG Terminals Serving New England
Jan 2009 – Sep 2011



Sources: 2009 & 2010 DOE *Natural Gas Imports and Exports* Reports and NEB.

The region also has an extensive network of LNG peak-shaving facilities attached to and owned or contracted for by LDCs for service to retail gas customers during the coldest days of the year. These peak-shaving facilities are essentially small satellite LNG storage tanks strategically located to provide service during peak consumption periods. They are able to remove gas from storage quickly, providing reliability and flexibility to the gas system. For example, the Connecticut LDCs rely on these facilities to meet their peak design day needs. However, they are slow to refill and are able to provide roughly only ten days of service at maximum output.

Although U.S. natural gas prices have declined considerably with the growth of unconventional gas production, reducing utilization of some LNG terminals, the LNG terminals and peak shaving facilities will continue to play an important role in New England's gas supply. Especially during peak periods, they will help to maintain the flexibility and reliability of the natural gas system. The extent of future LNG imports will depend in part on world LNG market conditions relative to domestic supplies. The Neptune and Northeast Gateway LNG facilities, although not utilized much recently, may provide a supply backstop to protect the New England gas market in the future. The availability of significant LNG capacity into New England load centers could mitigate price increases in the event of tight domestic natural gas market conditions (*e.g.*, if unconventional gas fails to meet current expectations), or when pipeline capacity limitations (*e.g.*, on AGT or TGP) restrict gas flows into New England.

Storage is also another important component of the New England gas supply. Although New England does not have its own underground gas storage fields, it has access to and relies upon gas storage facilities in West Virginia, Pennsylvania, and New York. Typically, the New

England LDCs contract for gas storage in these facilities and inject gas into storage during the summer when demand for gas is lower. This gas is subsequently withdrawn during the winter and delivered to New England via the long-haul pipelines discussed above.

Natural Gas Deliverability into New England Demand Centers

In U.S. gas markets, the gas commodity is unbundled from the pipeline transportation services required to deliver that gas to the ultimate consumer. That is, transportation and the gas commodity are priced and transacted separately. Contracts for gas pipeline transportation, including contracts on the pipelines serving New England, generally are offered in two distinct services — firm and interruptible. Firm transportation contracts have the highest possible guarantee of delivery, and are generally not subject to interruption except in cases of pipeline maintenance or in the event of Force Majeure.[19] In contrast, interruptible transportation contracts are subordinate to firm transportation contracts and thus are only scheduled after the firm customers are accommodated.

In Connecticut, firm primary pipeline capacity into the state totals 872,000 MMBtu/day. Of that amount, TGP delivers 370,000 MMBtu/day that enters the state from two directions, from the New York border near Greenwich, Connecticut and via the Massachusetts border near Suffield, Connecticut. Both entry routes are fully subscribed. AGT also delivers 384,000 MMBtu/day, entering at the New York border near Danbury, Connecticut and leaving the state near Thompson, Connecticut. This forward haul route is also fully subscribed. Iroquois, also fully subscribed, delivers 118,000 MMBtu/day into Connecticut at large interconnects with two LDCs, a power generator, and AGT and TGP.

Of this 872,000 MMBtu/d of firm capacity into Connecticut, generators hold only about 10%, while LDCs hold over 80%, as shown in Figure 7. The situation is similar across New England. Pipelines serving the region are essentially fully subscribed (*i.e.*, pipelines have sold 100% of available firm capacity); the local gas distribution companies hold the majority of the mainline firm capacity, with some capacity held by electric generators and marketers.

Figure 7
Firm Capacity Holders on Pipelines Serving Connecticut
(000s MMBtu/d)

Pipeline	LDC	Generator	Marketer	Total
Algonquin	310	50	24	384
Tennessee	340	4	26	370
Iroquois	58	35	25	118
Total	708	89	75	872

Sources: Algonquin Gas Transmission, Tennessee Gas Pipeline & Iroquois Gas

[19] A firm capacity holder may nominate to flow gas from/to receipt/delivery points other than those designated as primary in their contracts. In such cases, the nominations are considered secondary and have a lower priority than nominations from/to primary points.

Transmission Electronic Bulletin Boards — Index of Customers.

Across New England, approximately 300,000 MMBtu/d of mainline firm capacity into New England is held by electric generators. This translates to roughly 1,600 MW of gas-fired capacity with firm gas supplies. In addition, Mystic units 8 & 9 (with combined winter capacity of roughly 1,700 MW) are directly served under a long-term fuel supply contract for LNG from the Everett terminal.[20] Thus, roughly 3,300 MW of gas capacity has firm gas or LNG supplies. In Connecticut, the firm capacity held by generators is roughly 90,000 MMBtu/d, which translates to 500 MW.

Still, most electric generators in New England choose not to purchase firm pipeline transportation capacity but instead to rely on interruptible transportation to meet their gas supply needs. Although the primary transportation capacity is fully subscribed in New England, not all of the capacity is always fully utilized by the firm shippers. On a given day, some capacity may be unutilized and available to serve interruptible shippers. During the summer, when LDC needs are the lowest (and electricity demand is the highest), much of the pipeline capacity is unutilized by the LDCs and thus available to interruptible shippers, such as power producers.[21] During the winter, however, when LDC demand is higher, there might not be enough capacity to fulfill all of the firm and interruptible transportation requests. In such cases, interruptible shippers face a reduction of scheduled quantities ("restrictions"). Depending on the specific circumstances, the restrictions may be small or large relative to the nominated quantities.

Figure 8 and Figure 9 show restrictions during the last few years on two major pipelines serving Connecticut. From November 1, 2010 – October 31, 2011, AGT sealed nominations (meaning that no nomination increases were allowed after the "timely" cycle) 65 times, and issued 162 restrictions and 1 Operational Flow Order ("OFO") at various locations.[22] Similarly, TGP's interruptible shippers also experienced restrictions on a number of days in the last few years, primarily in Pennsylvania and New York, a trend that appears to be growing. These figures do not quantify the magnitude of the restrictions and thus do not provide a full picture of the transportation capacity actually available to interruptible shippers.

[20] In 2000, the owner of Mystic generating facility entered into a 20-year LNG contract with the owner of the DOMAC Everett LNG facility. According to the August 2011 EIA-923 schedule 2 data, Mystic generating station received LNG from DOMAC under a firm LNG supply contract.

[21] The pipelines do perform annual maintenance during these "off-peak" periods (during summer) which can cause meter specific restrictions and subsequently reduced capacity availability. The schedule of these projects is posted by the pipelines but the extent and duration of the work and possible restrictions is not always known.

[22] An Operational Flow Order (OFO) is a mechanism to protect the operational integrity of the pipeline. OFOs require shippers to take action to balance their supply with their usage on a daily basis within a specified tolerance band. Shippers may deliver additional supply or limit supply delivered to match usage.

Figure 8
Restrictions on Algonquin Gas Transmission System
11/1/2010 – 10/31/2011

Location	**November 1, 2010 – October 31, 2011**	
	Seal Only	Restrictions
Mahwah Mainline	6	32
Stony Point	11	75
Southeast	2	30
Cromwell	25	24
Burrillville	21	1
OFO	One OFO was in effect during this timeframe	

Source: Algonquin Gas Transmission.

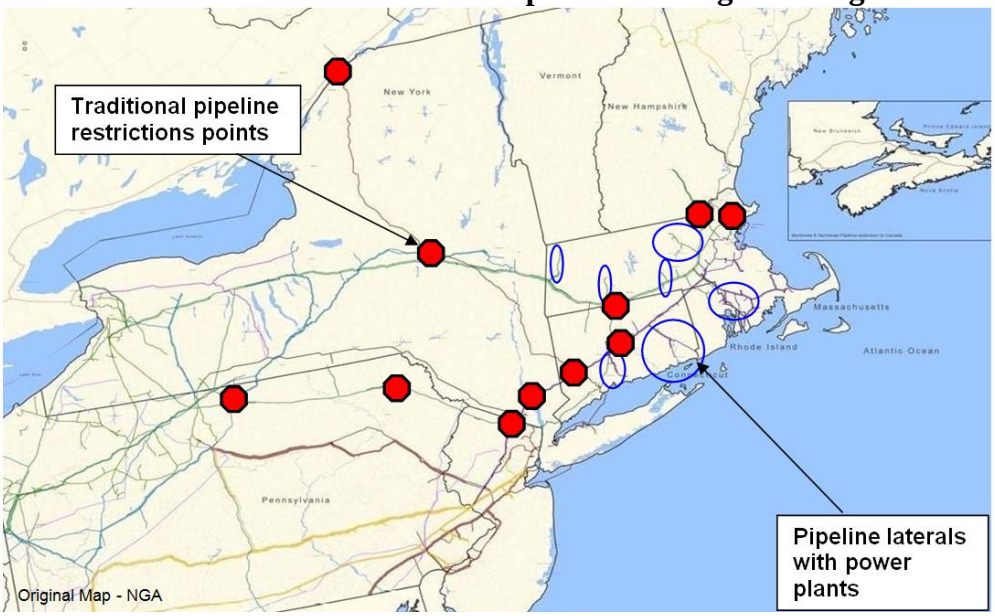
Figure 9
Restrictions on Tennessee Gas Pipeline
11/1/2010 – 10/31/2011

Restriction Point	**Percentage Days Restricted (April – October)**			**Restriction Point**	**Percent Days Restricted (Nov – Mar)**		
	2009	*2010*	*2011*		*2008/2009*	*2009/2010*	*2010/2011*
Sta. 219	11%	0%	0%	MLV 223/STA 224	25%	0%	28%
Niagara Spur Backhaul	0%	40%	11%	Niagara Spur Backhaul	0%	1%	38%
Sta. 224/ HC	0%	7%	44%	STA 245	43%	42%	96%
Sta. 245	0%	22%	79%	STA 307	21%	0%	1%
MLV 314 M/S	0%	0%	9%	STA 315 M/S	0%	0%	25%
Sta. 315 M/S	0%	0%	100%	STA 321	49%	38%	48%
Sta. 321/ 325	0%	12%	73%	STA 325	0%	0%	87%
MLV 355 S/M	0%	6%	81%	MLV 355 S/M	0%	0%	28%

Source: Tennessee Gas Pipeline.

As Figure 10 below shows, there have been numerous historical restriction points on the mainline sections of the interstate pipelines serving New England, where operating conditions constrain the flow of gas transported on a secondary or interruptible basis. But even when restrictions are imposed, firm shippers, including electric generators with firm transportation contracts, would receive their scheduled gas supplies (barring Force Majeure).

Figure 10
Historical Restriction Points on Pipelines Serving New England



Sources and Notes: Original Map — NGA, Restriction points and pipeline laterals with power plants were identified from information provided on the pipeline electronic bulletin boards for AGT, TGP and IGT.

Interactions between Gas and Electric Sectors

New England's electric sector is heavily reliant on natural gas for fuel, and likewise, the electric sector can put significant demands on the gas delivery system.[23] This has raised two primary types of concerns. First, since gas generally sets the New England power price, and the price of gas is itself quite volatile, the electric sector is exposed to gas price volatility. If gas prices increase materially, wholesale power prices go up and customer costs increase. Since the price set by the marginal generator is applied to all energy transacted in the ISO's wholesale market, this effect on electricity prices and costs is magnified beyond natural gas's share of generation. The high and low gas price scenarios simulated in this IRP and discussed in Section IV of the report (Alternative Futures) directly examine the electricity price and cost risks associated with natural gas dependence.

The second potential risk of gas dependence relates to system reliability. ISO New England has identified "the region's exposure to temporary interruptions to the fuel supply for natural gas-fired generators" as one of the key risks for the region's power system.[24] This exposure arises because New England's gas supply infrastructure is used both to provide gas to electric generators, and also to supply natural gas directly to the region's core residential and commercial

[23] New England is the relevant geographic scope for assessing risks due to natural gas dependence. Both the electricity and natural gas markets generally span New England. Connecticut is an integral part of these larger regional markets, but is not a separate market unto itself and does not face risks that differ materially from those facing New England as a whole.

[24] Gordon van Welie, ISO-NE, memo re Strategic Planning Directions to NEPOOL Participants Committee, New England Conference of Public Utilities Commissioners, September 1, 2011.

gas users. Unlike coal or oil which can be stored in large quantities on-site, natural gas is a "just-in-time" fuel which must be transported to the generator by pipeline and delivered as it is burned. As the New England electric sector's use of natural gas has increased over time, the interplay between the gas and electric sectors has caused reliability concerns focused on the extreme winter weather conditions that can tax the gas delivery system's capabilities. Many New England gas-fired generators have gas delivered on an interruptible basis rather than contracting for firm gas transportation. When the gas delivery system's capability is stressed, core gas customers have priority and electric generators without firm gas supplies may not be available to obtain fuel, potentially threatening system reliability. This issue is discussed in Appendix B (Resource Adequacy). Likewise, the power system's demand for large quantities of gas can impact the regional natural gas infrastructure, as discussed below.

Electric sector natural gas consumption in New England has increased in the last few years. Although variation in seasonality between electric and heating demand contributes to available pipeline capacity for gas-fired generators in the summer, the New England gas system can be stressed during the winter peak, serving both heating and electric generation demand. The system is generally sized only to serve the needs of firm customers (predominantly LDC residential and commercial loads but also some electric generation). The continued growth in electric sector demand, without expansion of the New England pipeline system, has caused concern for some LDCs due to the substantial amount of gas that can be consumed by gas-fired generators. The short-term variations in their gas usage have caused some operational difficulties recently.

Electric demand for a single gas unit can be substantial; a 620 MW combined-cycle unit with a 7,000 Btu/kWh heat rate can burn as much as 100 MMcf/d of gas. On top of increased overall gas demand during winter, the hourly flow variations often demanded by power generators (*e.g.*, ramping up and down over the course of a day to meet load) can put additional strain on the interstate pipelines, which are generally designed to provide relatively constant hourly flows. Of particular concern to LDCs and the pipelines are short notice generators who have an obligation to the ISO to generate electricity with a notice of an hour or less. With such short notice, these units might have difficulty balancing their burns relative to their scheduled quantities, which can cause operational difficulties when the pipeline is fully loaded, including pressure problems that create concerns about pipeline integrity. For example, TGP experienced critically low pressures on December 10, 2010 due to over-takes on its system, and issued an OFO notice. AGT has also experienced similar situations recently: last winter, certain customers were taking as much as 24% above scheduled deliveries even while AGT posted notices requesting all customers to limit their daily takes to within 2% of scheduled volumes.

In order to maintain the integrity of their systems, the New England pipelines have instituted numerous measures. Pipelines now are tightening their rules on imbalances, increasing imbalance penalties, implementing "Operational Flow Orders" (OFOs), and requiring power plants to submit burn profiles.[25,26] These actions will help the integrity of the gas system but will limit the flexibility previously provided to electric generators in New England.

Pipeline Expansion Projects and New England Access to the Marcellus Shale

Currently, pipeline capacity bottlenecks separate New England natural gas demand centers from the rapid supply growth in the Marcellus Shale. The Marcellus production area has seen a dramatic increase in pipeline expansions as producers and marketers attempt to find markets for this prolific resource. This trend seems likely to continue as more pipeline projects are built to increase takeaway capacity from the Marcellus. However, the vast majority of these pipeline projects have not resulted in incremental pipeline capacity into New England, and none have increased pipeline capacity to Connecticut. Nonetheless, Marcellus supplies are being delivered to New England as they are displacing traditional supply sources, such as Gulf Coast and Canadian gas imports, on the existing pipelines that serve New England.

There is considerable uncertainty regarding the amount of future pipeline capacity that will be available to transport Marcellus gas to New England. The Algonquin Gas Transmission "AIM" project could increase capacity to New England and Connecticut. It is currently being reviewed by the pipeline after non-binding bids were submitted during the first quarter of 2011. The Tennessee Northeast Supply Diversification project does not provide incremental capacity to Massachusetts and Rhode Island, but instead uses existing capacity (formerly held mostly by power generators) that did not have renewal rights as part of a project to allow shippers to change receipt areas to the Marcellus rather than Canadian receipt points. If additional pipeline capacity were to be built to New England in conjunction with additional takeaway capacity from the Marcellus, this could mitigate some of the seasonal basis price spikes (discussed in the next section) that have been observed in New England historically. Figure 11 shows recent and proposed gas pipeline expansion projects in the Northeast.

[25] TGP recently notified its customers that, in event of falling pressures, it will a) communicate with the ISO, b) notify plant operators who are overtaking to reduce their burn rate, and c) control the gas received by the generators. The pipeline also said that it may issue OFOs or physically restrict flows to maintain takes at a desirable level. See "TGP Winter Operating Discussion: Regional Focus on Power Plants," presented by Anders Johnson, Director Gas Control and Facility Planning, November, 16, 2011, slides 37–38.

[26] AGT also recently made changes to its tariff to enable it to target customers that are not taking gas in accordance with confirmed and scheduled nominations to protect the integrity of the system. See 134 FERC ¶ 61,008.

Figure 11
Northeast Natural Gas Pipeline Infrastructure Projects

Project Name	Pipeline	Description	In-Service Date	Status
TGP 300 Line	Tennessee	TGP Marcellus->NY	11/1/2011	In-Service
CYNOG North-South	Stagecoach	Storage Wheeling	11/1/2011	In-Service
Laser PA-NY Gathering	Laser	Marcellus->Millenium	12/1/2011	In-Service
Williams Springville Gathering	Transco	Marcellus-> Transco	12/1/2011	Construction
Northeast Supply Diversity	Tennessee	Marcellus-> TGPZ6	11/1/2012	Construction
Northeast Upgrade	Tennessee	Marcellus->NY	11/1/2013	Construction
TEAM	TETCO	Marcellus-> M3	11/1/2012	Regulatory Review
NJ-NY Expansion	TETCO	Marcellus->NJ/NY	11/1/2013	Regulatory Review
NY-PA Northeast Expansion	Tennessee	Marcellus-> TGP Z5	2016/2017	Open-Season
NYMARC	Iroquois	Marcellus->IGT	2014/2015	Open-Season
AIM	Algonquin	Forward-haul Expansion	2015/2016	Open-Season

Sources: Pipeline Electronic Bulletin Boards

NATURAL GAS PRICE FORECAST AND SCENARIOS

Base Case Forecast

Future fuel prices are an important component of a planning study such as this, particularly for natural gas, the key price-setting fuel in New England power markets. But of course it is impossible to predict future natural gas prices with accuracy and precision. Past gas prices have varied considerably, and have deviated widely from prior forecasts and predictions, including the market's own "forecasts" of natural gas prices, including NYMEX futures prices for natural gas.

However, while future natural gas prices cannot be predicted with high confidence, it is possible to develop a reasonable characterization of their likely value and the potential range over which they may vary. Though a wide range of potential gas prices may be plausible, in order to understand the effect on the power system it can be useful to examine several particular gas price levels that are chosen to illustrate the potential range. Considering several different scenarios on natural gas prices — *e.g.*, Expected, High, and Low gas price cases — in combination with other variables that affect the power system, can be an important part of evaluating different resource strategies.

The relevant natural gas price for the New England power market is the delivered spot price faced by generators. (To the extent a given generator may pay a different price for gas, *e.g.*, because they have hedged their gas price or taken gas under long-term contract, the spot price is still the relevant reference price, since it represents their opportunity cost. If they do not burn the gas to generate power, they can resell it at the spot price, or buy more at that price.) The delivered spot price can be thought of conceptually as the sum of three components:

- Commodity Price (typically quoted at Henry Hub, Louisiana).
- Basis Differential (difference between New England price and Henry Hub price).

- Variable Local Transportation Adder (variable portion of local distribution charges).

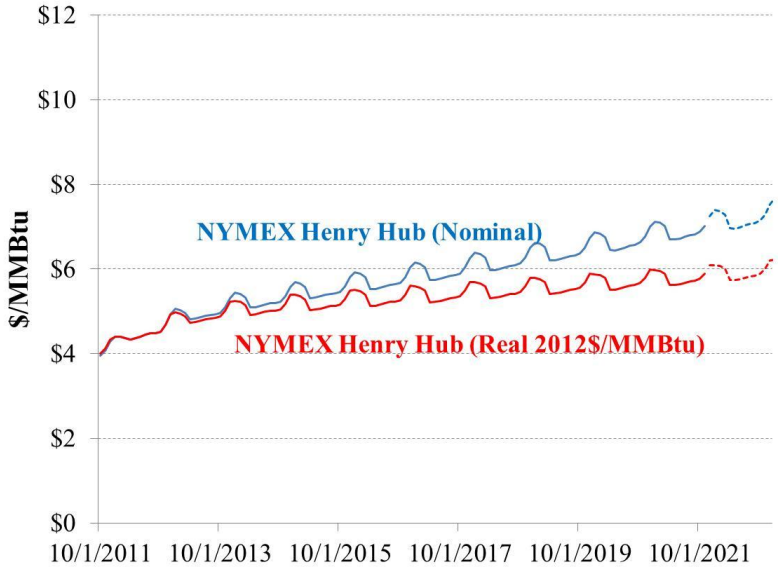
Of course, a given generator may face other costs associated with gas procurement, but in general these are fixed costs that do not affect their variable cost-based offers into the New England power market, and thus do not affect energy prices.

Commodity Price

The commodity price is the largest of the three components, dominating both in terms of magnitude and in the level of uncertainty it implies for the overall delivered price. There are several potential sources of commodity price projections, including market data from futures contract prices, EIA's Henry Hub spot price outlook, and proprietary price forecasts from firms such as Wood Mackenzie. For this study, Henry Hub natural gas futures contracts transacted on NYMEX were chosen as the basis for the commodity price portion of the Base Case gas price forecast. These standardized exchange-traded forward contracts are widely traded for a number of years into the future, and essentially reflect the market's "expectation" of future gas prices (though strictly speaking, the futures price also includes a risk adjustment). NYMEX Henry Hub futures prices on 30 transaction days between August 5, 2011 and September 15, 2011 were averaged to get the base case commodity price.

Adjusting for inflation, current futures show gas prices increasing from roughly $4/MMBtu in the near term to reach $6/MMBtu (in real 2012 dollars) over the next 10 years, shown in Figure 12. The blue line shows the actual NYMEX prices (average of 30 trading days), which are priced in nominal dollars, while the red line shows the same values converted to 2012 real dollars. The dotted lines represent the extrapolation of prices beyond available NYMEX data. Hereafter, references to prices will be in 2012 real dollars, unless otherwise noted. A comparison of the commodity price projection used in the current 2012 IRP with those used in the 2010 and 2009 IRPs was shown above in Figure 3. As discussed previously, gas prices have been trending downward significantly over the past few years, driven largely by the success of shale gas (and in the near term, depressed demand due to the economic downturn).

Figure 12
NYMEX Henry Hub Futures
30-Day Average (8/5/11 – 9/15/11)



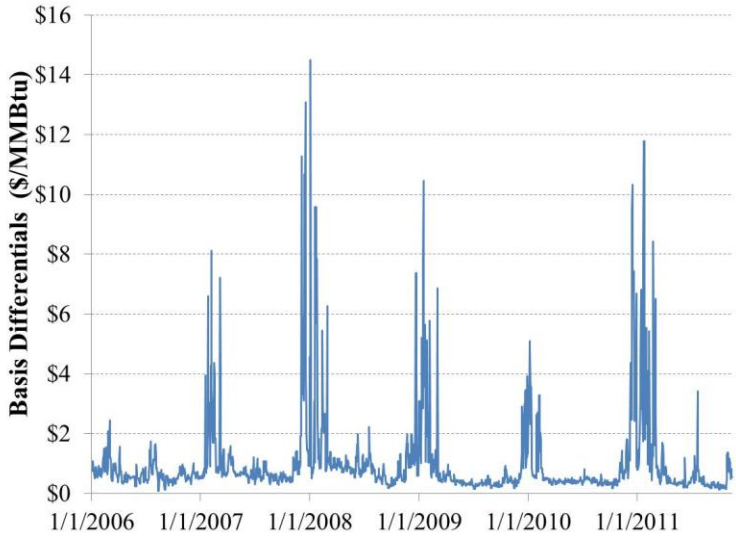
Source: NYMEX data obtained from Bloomberg.

Basis Differential

The basis differential is the gas price differential between two physical locations where gas is traded and prices are reported, in this case Henry Hub in Louisiana and New England gas markets.[27] High winter gas demands in New England result in heavy utilization of the gas delivery infrastructure, and consequently higher basis differential during these winter peaks. Figure 13 illustrates this, showing the daily basis differential between Algonquin Citygate and Henry Hub. There have also been occasional basis differential jumps during the summer, though they are much smaller — up to $2/MMBtu, versus winter differentials that commonly reach $6–8/MMBtu and occasionally exceed $10/MMBtu.

[27] The basis differential reflects the market value of transportation between two locations, and spot basis differentials can be quite volatile. Holders of firm pipeline transportation capacity generally acquire gas at production areas, storage fields, and liquid market hubs and transport it to delivery points specified in the contract. The price of firm pipeline transportation is federally regulated and cost-based. Thus, end users with firm pipeline capacity pay a cost-based price and are not exposed to swings in the spot basis differential. Other market participants without firm transportation contracts purchase gas at specific locations at prevailing spot prices and may be exposed to volatility in basis differentials.

Figure 13
Algonquin Basis Differential
Jan 2006 – Oct 2011



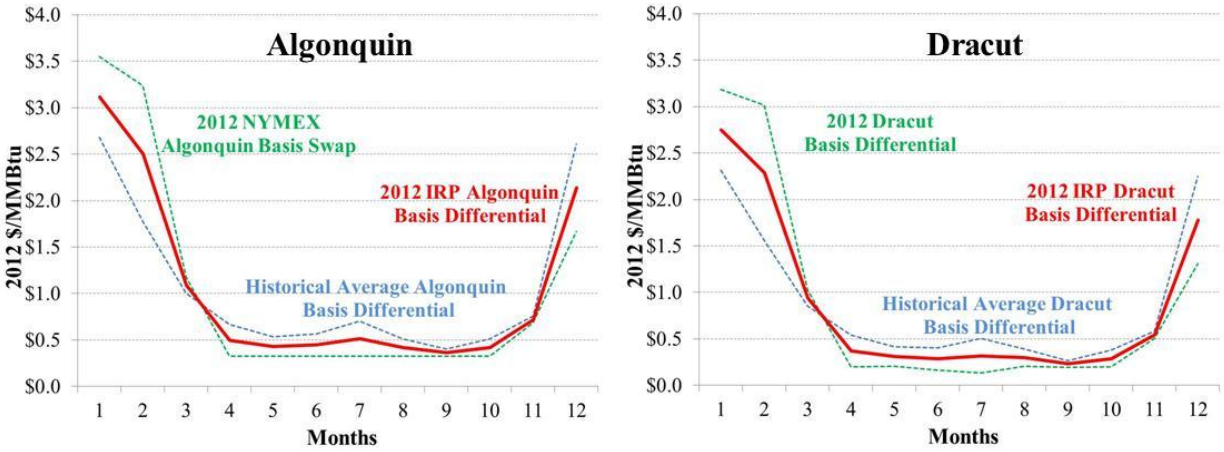
Source: Platts Gas Daily

In determining the relevant future basis differentials, we averaged the market's view of the forward basis differential (as reflected by NYMEX basis swaps) with observed historical basis differentials between Henry Hub and New England gas hubs.[28] In the long-run, basis differentials may be affected by changes in the geographic patterns of gas flows and prices (*e.g.*, as a result of growing unconventional supplies from new basins), and potential expansions of pipeline capacity serving New England. Averaging the historical and forward basis differential values reflects some of the recent changes in flow patterns but preserves the historical pattern of winter basis spikes experienced in New England (which is appropriate given the significant uncertainty regarding the timing of any potential expansions of the New England gas system). In light of this uncertainty, the New England basis differential was maintained constant in real terms going forward.

Figure 14 shows the basis differentials used for this planning study. As shown, the New England basis differentials display substantial seasonality, driven by increased gas demand for heating during the New England winter. Winter basis differentials are in the range of $3/MMBtu when gas demand is the highest, while summer differentials, when electricity demand is the highest, are only around $0.50/MMBtu.

[28] For Algonquin basis differentials, we averaged the 5-year historical (2006-2011) basis differentials with the 30-day (August 5, 2011 – September 16, 2011) average of 2012 NYMEX Algonquin basis swaps. For Dracut, we developed a proxy for the 2012 basis differential from the 2012 NYMEX Algonquin basis swaps, less the 5-year historical differentials between Algonquin and Dracut. While trading in the NYMEX basis market is thin (*i.e.*, much less liquid than futures prices at Henry Hub), basis swap prices are publicly available and provide an indication of forward basis differentials.

Figure 14
New England Basis Differentials



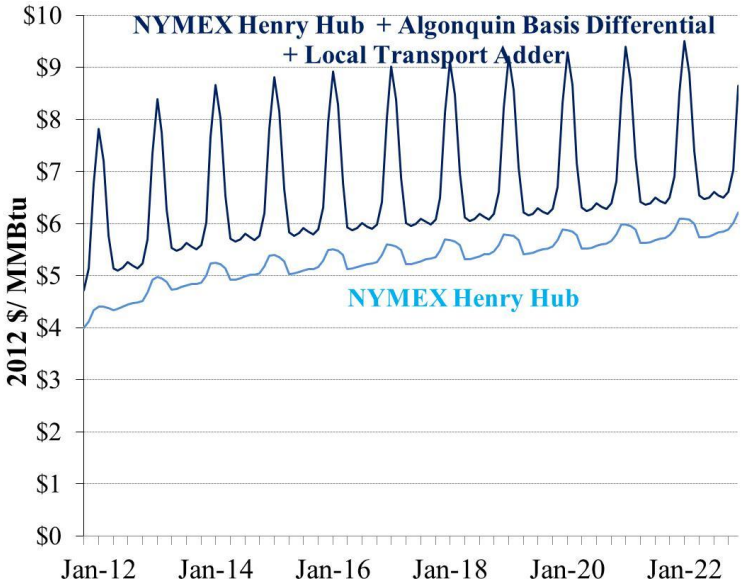
Sources: Gas daily, NYMEX data obtained from Bloomberg.

Variable Local Transportation Adder

Gas-fired generators in New England can be distinguished according to whether they are served by local distribution companies (LDCs), or are directly connected to an interstate natural gas pipeline. Generators served by an LDC typically pay a local transportation adder which reflects the cost of transporting gas on the local distribution network. This distribution cost paid by generators can vary by location and individual plant. For the purpose of this study, we use a uniform $0.30/MMBtu adder for all generators served by LDCs throughout New England, derived in consultation with the Connecticut LDCs and representing only the variable component of the local transportation charges (excluding any fixed capacity related charges).

Figure 15 illustrates the projected delivered price of natural gas to electric generators in Connecticut, which includes all of the three components discussed above (generators connected directly to interstate pipelines do not pay the $0.30/MMBtu local transportation adder).

Figure 15
Delivered Price of Natural Gas to Electric Generators in Connecticut
2012-2022



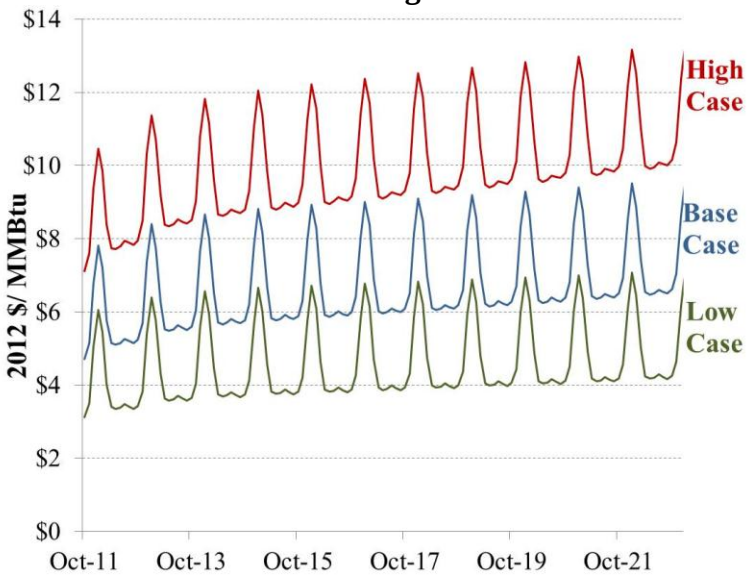
Source: NYMEX data obtained from Bloomberg.

High/Low Cases

In developing the high and low commodity price cases, we evaluated several factors including available high and low gas price forecasts from EIA, Wood Mackenzie, implied volatility from natural gas options prices, and historical NYMEX and EIA "forecast errors." Considering all of the available data and utilizing collective judgment of the gas sub-group, we determined that a high/low range relative to the base case commodity price forecast of roughly +60% to -40% captured a reasonable range of gas prices suitable for planning purposes.

We also considered developing high and low scenarios for the basis differentials. However, considering the uncertainties regarding future pipeline expansions (as discussed above), we decided to take a conservative approach and use the base case basis differential for both the high and the low cases. The final delivered high and low prices, shown in Figure 16, include the high and low commodity prices basis differentials, and the local transportation adder (for generators served by LDCs). The high and low delivered prices considered for this planning study range from $4-$6/MMBtu for the low case to $10-$13/MMBtu for the high case.

Figure 16
Natural Gas Price Scenarios
Delivered Price of Natural gas to Generators in CT



Source: NYMEX data obtained from Bloomberg.

Coal and Oil Prices

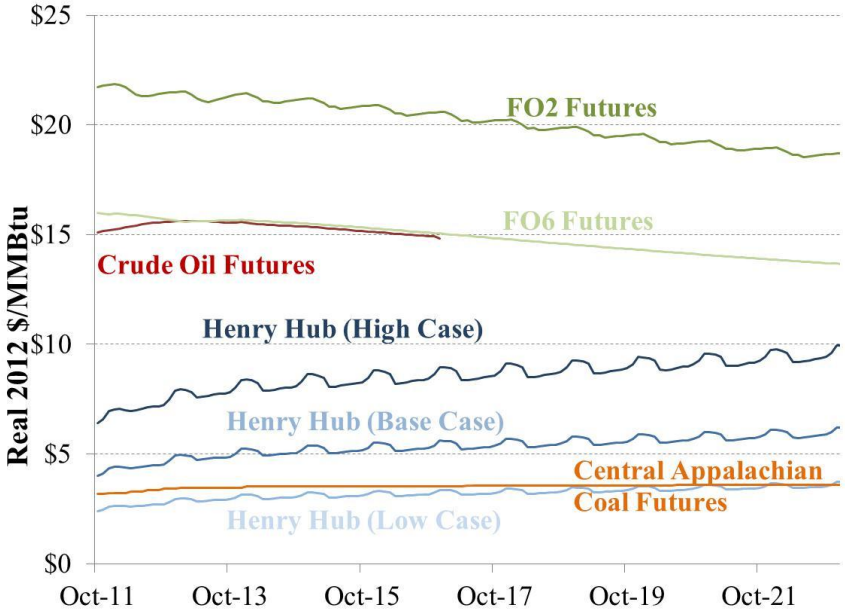
Oil in the form of FO2 (distillate) and FO6 (residual fuel oil) is also used in New England for power generation. Compared to natural gas, use of oil for generation in New England is relatively small, especially in the current environment where the price of oil is markedly higher than the price of natural gas (on an energy equivalent basis). Nevertheless, oil does contribute to some generation in New England and is also sometimes used as an alternate fuel.

We derive the forecasted prices for FO2 and FO6 using contracts traded on NYMEX.[29] For the forward years that these contracts are traded, we use the average of these prices during the trading days between August 1, 2011 and September 16, 2011. Thereafter, we use the growth rate in NYMEX "Light Sweet Crude Oil Futures" to escalate the fuel prices.

As can be seen in Figure 17, the natural gas futures prices in each scenario are significantly below oil futures prices on an energy equivalent ($/MMBtu) basis. This is noticeably different from the historical relationship where natural gas and oil prices were more closely linked, with natural gas prices often at roughly 85% of oil prices. Prices for these commodities have delinked in the last few years and market participants expect this to continue. Because of this, oil prices are maintained at their expected level across all scenarios.

[29] For distillate and residual fuel prices in New England, we use "New York Harbor No. 2 Heating Oil Futures" and "New York Harbor Residual Fuel 1% (Platts) Swap Futures" contracts traded on NYMEX as proxies.

Figure 17
Oil and Coal Prices Compared to Gas Price Scenarios



Source: NYMEX data obtained from Bloomberg.

Coal-fired power plants account for only about 11% of total New England electricity generation in 2010; well below gas, which generates over 40%.[30] As can be seen in Figure 17 above, coal still maintains a modest price advantage to natural gas, which is expected to continue in the future. However if natural gas prices were to decline substantially, *e.g.*, due to higher than expected production from unconventional gas resources, natural gas might gain a competitive advantage over coal. In any case, the New England electricity market will continue to be dominated by natural gas in the foreseeable future.

[30] "2010 Annual Markets Report," ISO-NE, June 3, 2011.

APPENDIX G

TRANSMISSION PLANNING

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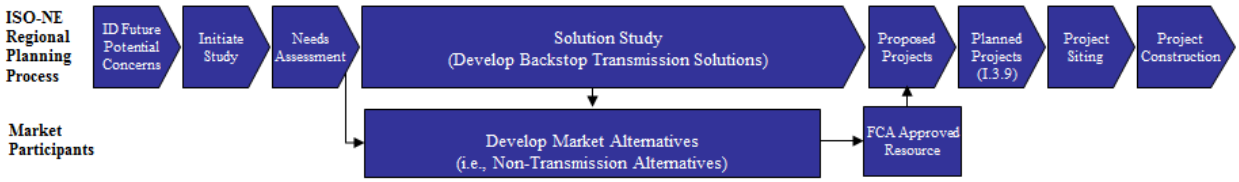
INTRODUCTION

This appendix describes transmission planning needs and processes that affect Connecticut. The first section summarizes identified transmission reliability needs and ongoing studies in Connecticut, particularly in southwest Connecticut and central Connecticut. The second section addresses non-transmission alternatives (NTAs), providing a summary of Connecticut's role in the NTA process ISO-NE is currently developing, and a classification of the types of transmission projects that may be suitable for replacement by NTAs. The third section addresses emerging issues affecting transmission planning.

TRANSMISSION RELIABILITY NEEDS AND STUDIES IN CONNECTICUT

As part of the ISO-NE regional planning process that supports compliance with NERC and NPCC planning standards, ISO-NE and transmission owners (TOs) perform reliability assessment studies of the New England transmission system. Individual sub-area studies ("Needs Assessments") are performed to identify system needs over a ten-year horizon. When a system reliability problem is identified from a needs assessment, ISO-NE and the TOs develop one or more transmission system options and alternatives (*i.e.*, backstop transmission solutions) to address all of the transmission reliability needs and ensure that NERC and NPCC reliability standards are met. (In parallel, market participants can develop and propose non-transmission alternatives, as discussed separately below). The viable transmission system alternatives are further evaluated to determine feasibility of construction, environmental impacts, costs, longevity, and operational considerations. When the analysis of the alternatives is complete, the TOs recommend a proposed transmission project to ISO-NE and the Planning Advisory Committee (PAC). These studies, and the proposed transmission solutions, are documented in a solutions study, and in aggregate provide the basis to update ISO-NE's Regional System Plan (RSP). Figure 1 depicts the sequence of this process.

Figure 1



There are two transmission reliability sub-area studies currently in progress in Connecticut. These studies, performed in collaboration with ISO-NE, are at various stages in the ISO-NE Regional Planning Process. They are as follows:

1. Southwest Connecticut (SWCT) Solution Study.

2. Greater Hartford/Central Connecticut (GHCC) Needs Assessment. This study includes a needs assessment of the Greater Hartford area (including Northwest Connecticut, Manchester, and Middletown areas) and a reassessment of the Central Connecticut Reliability Project portion of the New England East West Solution (NEEWS).

Potential reliability concerns and alternatives under evaluation are described below.

SWCT Solution Study

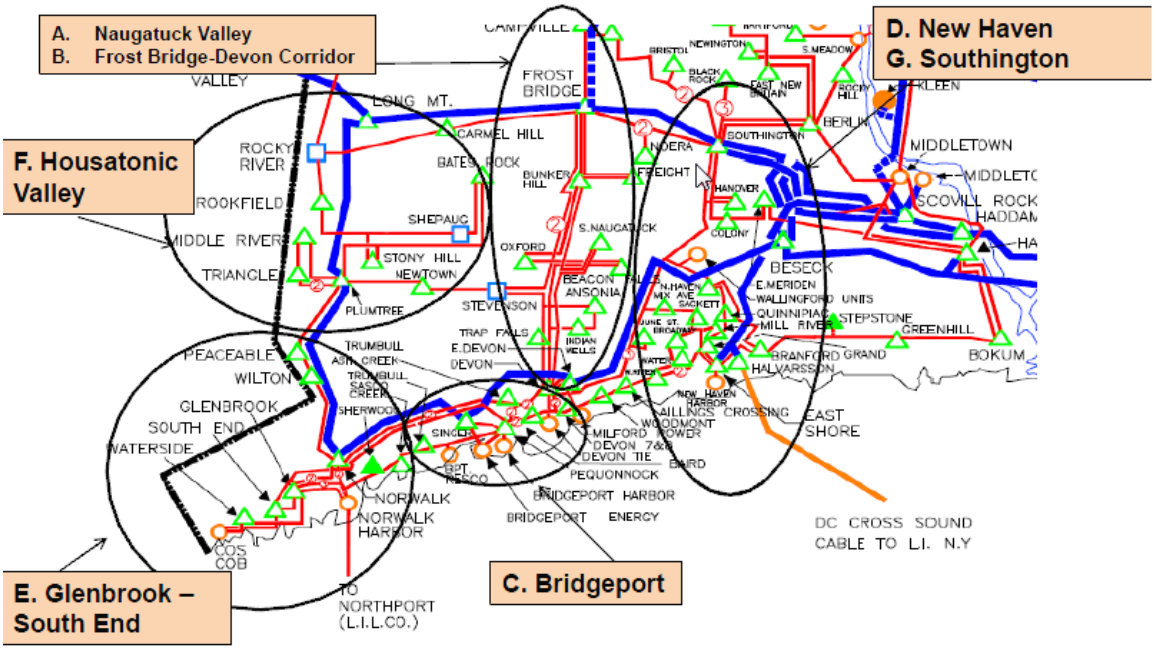
The "Southwest Connecticut Area Transmission Needs Assessment" study report was finalized by ISO-NE in July 2011.[1] Due to network complexity and load density, the SWCT study area was divided into the following sub-areas for the purpose of this study and the subsequent Solution Study:

A. Naugatuck Valley
B. Frost Bridge – Devon Corridor
C. Bridgeport
D. New Haven
E. Glenbrook – South End
F. Housatonic Valley (Rocky River – Stony Hill Corridor)
G. Southington.

Figure 2 shows the approximate location of these sub areas.

Figure 2

[1] The SWCT Needs Assessment, dated July 13, 2011, is posted on the ISO-NE website at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/index.html



Reliability concerns (*i.e.*, needs) identified in each of these areas are related to thermal, voltage, or short-circuit performance in accordance with NERC, NPCC, and ISO-NE reliability criteria.

In November 2011, ISO-NE presented an update of the in-progress SWCT Solution Study.[2] As described in this update, the majority of alternatives considered to date have "targeted" load pocket oriented (*i.e.*, minimal) solutions such as:

- Separation of double circuit towers/addition of series circuit breakers/ reconfiguration of lines to fix reliability problems.
- Upgrade of overloaded facilities: for example, re-conductoring of existing 115 kV transmission lines/upgrade of substation 115 kV buswork/terminal equipment.
- Install voltage support devices: For example, 115 kV capacitor banks/ series and shunt reactors

The analyses to date have also considered "Inter-Area" solutions, such as the construction of new transmission lines across SWCT sub-areas. If the performance and/or cost of the targeted sub-area alternatives do not achieve the desired results, further analysis may warrant consideration of Inter-Area solutions.

It is anticipated that conceptual transmission solutions (with order-of-magnitude cost estimates) to address SWCT needs will be presented to the Planning Advisory Committee (PAC) in the first

[2] The ISO-NE SWCT Solution Study Update presentation to PAC on November 16, 2011 is available on the ISO-NE website at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2011/nov162011/index.html

quarter of 2012. Preferred transmission solutions with more refined conceptual cost estimates will be presented to PAC in the third quarter of 2012.

GHCC Needs Assessment

A transmission reliability needs assessment for the Greater Hartford area, and a needs reassessment associated with the Central Connecticut component of the New England East West Solution (NEEWS) Project have been combined into one study.[3] The scope of this study has also been expanded to include the Manchester, Middletown, and Northwest Connecticut areas.

The Greater Hartford transmission system experiences flow-through and load-supply issues under certain dispatch patterns, contingency conditions, and transfer conditions. The reliability concerns (*i.e.*, needs) identified in each of these areas are related to thermal, voltage, or short-circuit performance in accordance with NERC, NPCC, and ISO-NE reliability criteria.

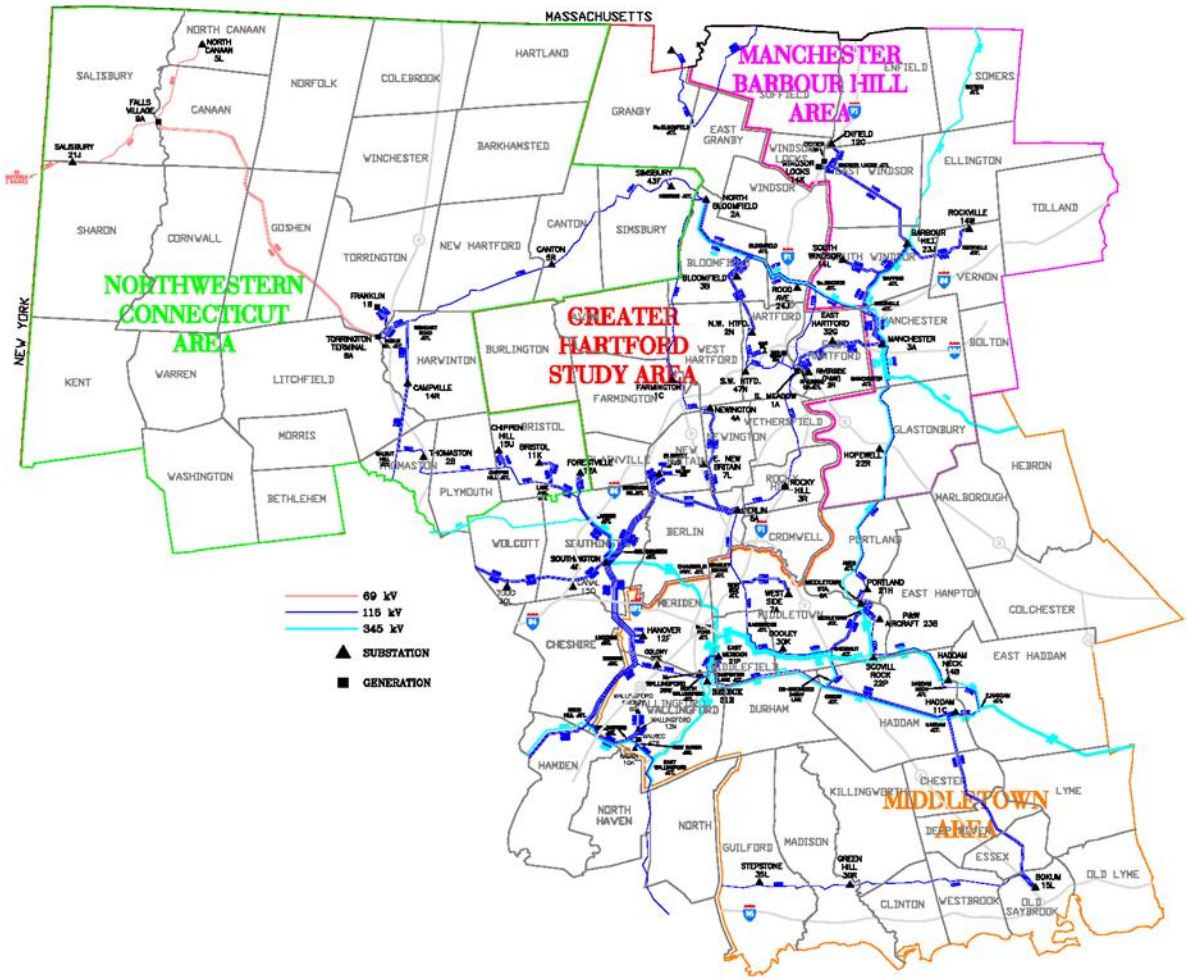
As shown in Figure 3 below, the Greater Hartford/Central Connecticut area has been divided into following four sub-areas for the purposes of this study:

A. Greater Hartford
B. Northwest Connecticut
C. Middletown
D. Manchester/Barbour Hill

This study currently is in the needs-assessment stage, and it is anticipated that the needs assessment study and an ISO-NE Alternatives Analysis study will be completed and presented to PAC in 2012. Conceptual transmission solutions (with order-of-magnitude cost estimates) to address needs will follow.

[3] Scope of Work (March 16, 2011), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2011/mar162011/ghcc.pdf

Figure 3.



CONSIDERATION OF NON TRANSMISSION ALTERNATIVES

Much activity has taken place in Connecticut and New England over the last several years regarding how to assess non-transmission alternatives (NTAs) as a substitute for backstop transmission reliability solutions. Recent Connecticut IRP decisions have recognized the importance of coordination between the states and ISO-NE in development of an integrated NTA process. Connecticut, as well as other New England states, has provided ISO-NE input for their consideration, which has led to the conceptual development of an ISO-NE regional NTA process that seeks to align markets and planning.

The conceptual ISO-NE NTA process, which includes NTA analysis early enough to identify those cases where market resources could practically address the identified transmission reliability needs, also recognizes the need for a potential change to the ISO-NE market design to facilitate the procurement of effective and feasible NTA resources.

The 2010 IRP discussion on conceptual, proposed, and planned transmission reliability projects in Connecticut and their characteristics is summarized and updated below. In addition, we propose a classification of the types of reliability projects that may be suitable for substitution by non-transmission alternatives.

NTA Process Discussion

The State of Connecticut intends to build upon previous IRP decisions and to engage in the creation of a region-wide NTA process. Several states, including Connecticut, approached ISO-NE about the timing of NTA analysis and the need to better align markets and planning. The alignment of NTA processes with ISO-NE regional processes is imperative and has been recognized in prior Connecticut IRPs. Therefore, a Connecticut-specific NTA process is not being proposed at this time; rather, Connecticut will support the development of the recently announced conceptual ISO-NE NTA process. This process is part of ISO-NE's Strategic Planning Initiative and is described in an ISO-NE whitepaper.[4] Key concepts included in the process are described below and illustrated in Figure 4.

As described in ISO's white paper, "the ISO's broad objective is to modify the planning processes and resource adequacy markets (*i.e.*, the Forward Capacity Market and the Forward Reserve Market) to enhance the ability of market resources to more fully address the reliability needs identified through the planning process. Reliability needs may be: resource adequacy needs, which arise when the region has insufficient capacity to meet its load and reserve requirements; or transmission security needs, which occur when power system flows are outside specified design or operating limits (*e.g.*, thermal or voltage levels, respectively)."

Analysis of NTAs to potentially solve transmission reliability needs will be performed once transmission reliability needs are initially understood, instead of waiting for the final completion of a needs assessment report, or the commencement of the transmission solution study. ISO-NE's white paper implies that initiating the NTA analysis at this early stage improves the planning process by helping to:

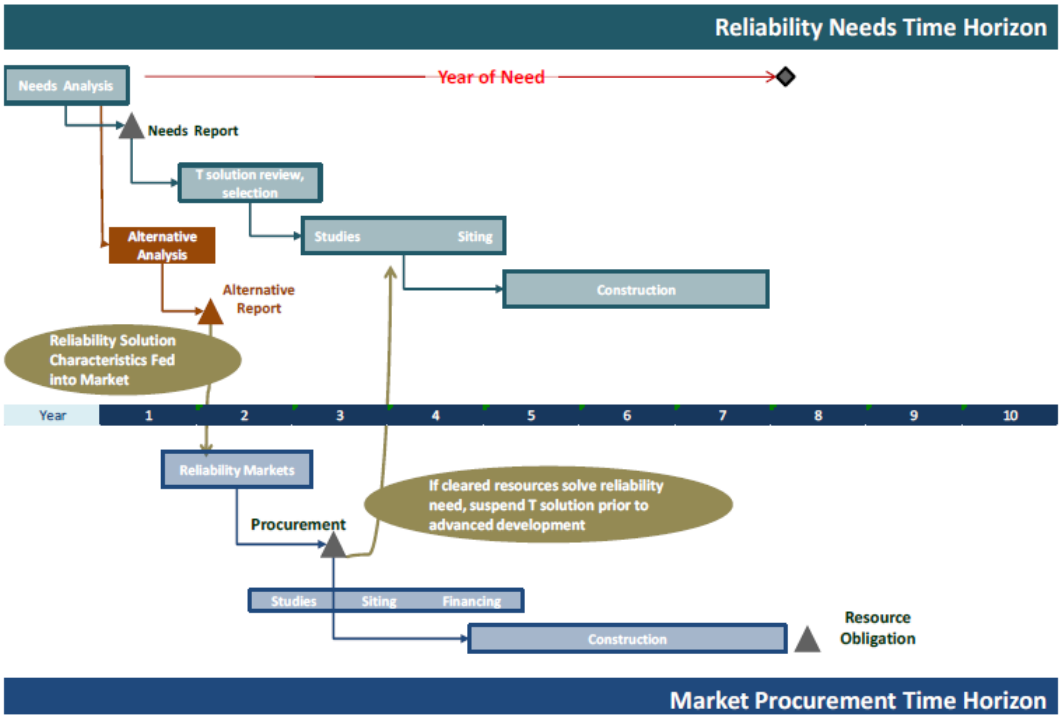
- Provide information in identifying which of the transmission reliability needs could be resolved with a market resource and which of the needs are best suited for a transmission solution.
- Allow market participants to develop NTAs in parallel with the development of transmission backstop solutions (*i.e.*, Solution Studies). This allows adequate opportunity for participants to propose market resources that might address identified reliability needs without affecting or hindering the timing of the backstop transmission solution.

[4] See ISO-NE "Aligning Planning and Markets," white paper dated October 27, 2011: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/2011/alignment_of_markets_and_planning_white_paper.pdf.

- Consider potential market design changes that may encourage the procurement of market resources that solve the transmission reliability needs as substitutes for transmission solutions, early enough that the backstop transmission solution could be (1) implemented in time to meet the needs, or (2) suspended prior to advanced development.

Figure 4
Alignment of Markets with Planning

If a Market Resource Alternatives analysis can be completed in a timely manner, needs can feed into market procurements, potentially eliminating or changing T solution prior to advanced development / construction



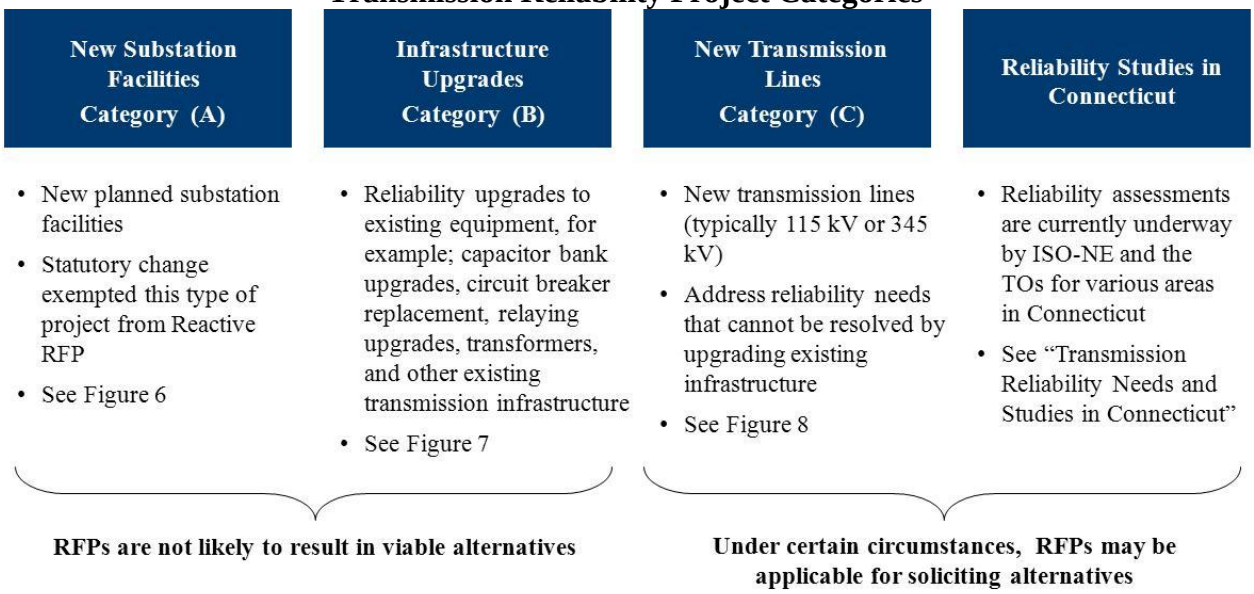
Source: Figure 4 in ISO-NE's whitepaper, "Aligning Markets and Planning," October 27, 2011.

Types of Reliability Projects That May Be Suitable for NTAs

In the EDCs' 2010 IRP, the following criteria were proposed for determining the regional reliability projects/needs in Connecticut that may be viable candidates for the consideration of non-transmission resources as alternatives to a backstop transmission solution. These criteria may be used by the State to supplement the ISO-NE NTA process by clarifying the characteristics of transmission projects that may be considered as possible NTA candidates.

Commencing with the Regional System Plan and the ISO-NE area needs assessment reports for system reliability as discussed previously, transmission reliability projects planned for Connecticut can be categorized as outlined below in Figure 5 and described in more detail in the subsequent sections.

Figure 5
Transmission Reliability Project Categories



Category A — New Substations (and Significant Additions to Substations)

Category A includes new substation facilities that are planned to ensure that the reliability and demand needs of end-use customers are met. In recent years, the Connecticut Energy Advisory Board (CEAB) solicited RFPs for alternatives to planned new substations as part of the CSC's Reactive RFP process. These resulted in no respondents for all of the four RFPs issued. Subsequently, the applicable statute was amended to exempt substations from the Reactive RFP Process. It appears that projects in this category are not likely to result in viable NTAs, therefore it is recommended that they be waived from NTA consideration. Figure 6 summarizes future Connecticut projects in this category, as listed primarily from the ISO-NE November 2011 Project Listing approved by PAC, excluding LSP projects.

Category B — Infrastructure Upgrades

Category B is for various reliability upgrades to existing substations and other existing transmission infrastructure, typically necessary to address the following specific reliability concerns: (1) high system short-circuit current levels, (2) low thermal ratings of equipment and conductors, (3) poor voltage performance/voltage collapse exposure, (4) system instability risks, (5) antiquated/obsolete equipment, and (6) risk of equipment failure related to age/condition. Figure 7 summarizes future Connecticut projects in this category, as listed primarily from the ISO-NE Regional System Plan Project Listing.

Substations: These upgrades are performed within the fenced-in perimeter and often include replacement, addition, or upgrade of existing infrastructure. Examples include: relaying and control systems, transformers (*i.e.*, transmission to distribution transformation), auto-transformers, circuit breakers, disconnect switches, bus systems, grounding systems, auxiliary equipment such as potential transformers, current transformers, batteries, lightning arrestors, and reactive devices (such as shunt capacitors, shunt reactors, static VAr compensators, phase-angle regulators, *etc*.) and other substation associated equipment.

Other Transmission Infrastructure: These upgrades are generally needed to ensure the reliable operation of the existing integrated electric system network, typically within the same right-of-way. Examples include separation of structures, thermal ratings upgrades (reconductoring, rebuilding or retensioning of structures and/or conductors), replacement of structures, and reconfiguration of lines required for the purpose of interconnection of generators and/or substations.

Non-transmission resources are generally not effective in addressing the reliability concerns addressed by projects in this category. Consequently, it is recommended that reliability upgrades to existing substations and other existing transmission infrastructure be waived from non-transmission alternative consideration.

Category C — New Transmission Lines

Category C includes new transmission lines (typically 115 kV greater than 5 miles in length or 345 kV in Connecticut) proposed as backstop solutions intended to address specific reliability needs that cannot typically be addressed by upgrading existing infrastructure. Figure 8 summarizes future Connecticut projects in this category, as listed primarily from the ISO-NE Regional System Plan Project Listing. Although this category has attracted the most interest in recent years, there are only a few projects included in the listing at this time. However as described above, several reliability studies are underway in Connecticut, and/or may be initiated in the near future. Depending on the ISO-NE needs assessments, transmission backstop solutions may be identified in the future that would qualify for Category C. As discussed above, the State continues to support the development of the recently announced conceptual ISO-NE NTA process, and in conjunction with future ISO-NE NTA analysis, identifies opportunities for NTAs as potential substitutes for backstop transmission reliability solutions.

Application of Proposed Criteria to ISO-NE RSP 2011 Transmission Reliability Projects in Connecticut

Category A, B, and C Projects

The figures below provide a summary of Connecticut transmission reliability projects shown in the Project Listing dated November 2011 (updated as applicable). The projects are grouped into the categories summarized above (A, B, or C):

Figure 6
Category A — New Substations (and Significant Additions)

Project Name	Location	Owner	RSP Project ID	Description	Projected In-Service Year	Status
South End S/S	SWCT	NU	1227	Addition of a 115/13.8 kV transformer & reconfiguration to transmission	2012	Planned
Shelton S/S	Shelton	UI	721	New 115/13.8 kV substation	2014	Planned
Northeast Simsbury S/S Breaker Addition	Simsbury	NU	1230	Add 115 kV breaker at Northeast Simsbury Substation	TBD	Concept
East Shore Distribution S/S Capacity Increase	New Haven	UI	New	Upgrade of existing 115/13.8 kV distribution substation equipment	2013	Proposed
South Norwalk Electric Works (SNEW) S/S	Norwalk	CMEEC	1242	New 115/13.8 kV substation	2012	Proposed
Fitch Street S/S	Norwalk	CMEEC	1243	New 115/ 27 kV substation	2013	Concept
Newtown	SWCT	NU	LSP	Add a 3rd 115/13.2kV Transformer	2012	Concept
Norwalk	Norwalk-Stamford	NU	LSP	Add a 115/13.2kV transformer	2014	Concept
North Bloomfield	Greater Hartford	NU	LSP	Add a 115/23kV transformer	2014	Concept
Canal	SWCT	NU	LSP	Add 115/23kV transformer	2015	Concept
Greenwich S/S	SWCT	NU	LSP	New 115/27 kV substation	2017	Concept

Note: "LSP" means Local System Plan.

Figure 7
Category B — Infrastructure Upgrades

Project Name	Location	Owner	RSP Project ID	Description	Projected In-Service Year	Status
Millstone 345 kV Circuit Separation	Various	NU	1218	Separate the four 345 kV lines out of Millstone	2013	Planned
8300 Line Reconfiguration	New Haven	UI	1246	Reconfigure 8300 115 kV line	2013	Proposed
Naugatuck Valley 115 kV Reliability Improvement	Shelton & Derby	UI	699	Upgrade and reconfigure transmission, separate structures	2014	Concept
South Meadow S/S BPS Upgrades	Greater Hartford	NU	85	Upgrade station to NPCC BPS standards	TBD	Concept
1990 Line Lattice Structure Replacement	SWCT	NU	1229	Replace 115 kV 1990 line (Frost Bridge – Stevenson) Lattice Structures	TBD	Concept
Pequonnock S/S Fault Duty Mitigation	Bridgeport	UI	975	Solution in Development	2015	Concept
Dynamic Swing Recorders to	Various	NU	879	Upgrade 7 of 8 Dynamic Swing Recorders to comply with NERC,NPCC and ISO-NE Standards	TBD	Planned
Stockhouse Substation Upgrade	Eastern CT	CMEEC	1244	Install 115kV Bus tie Breaker	2011	Proposed

Figure 8
Category C — New Transmission Lines

Project Name	Location	Owner	RSP Project ID	Description	Projected In-Service Year	Status
NEEWS	CT/RI/MA	NU	802 810, 191 1085	Interstate Reliability Project[5]	2015	Planned (In Siting Phase)
NEEWS	CT	NU	576 1114	Central Connecticut Reliability Project[6]	2016	Planned
Glenbrook – South End 115 kV UG Line Addition	Stamford	NU	1228	Build Glenbrook to South End 115 kV UG Line Addition[7]	2014	Proposed
Manchester – East Hartford	Greater Hartford	NU	801	Build a new Manchester to East Hartford 115kV Line[6]	TBD	Concept

EMERGING ISSUES AFFECTING TRANSMISSION

Several developments occurred since the 2010 IRP that affect transmission and reliability planning. Two FERC related developments are discussed in the section below: the FERC Order 1000 ruling on transmission planning and cost allocation, and the issuance of the FERC decision on the ISO-NE Minimum Offer Price Rule (MOPR) in the Forward Capacity Market (FCM). In addition, an update is provided on the Department of Energy (DOE) sponsored Eastern Interconnection Planning Collaborative (EIPC), which is well underway with the goal of examining the impact of various energy policy impacts on the entire Eastern Interconnection through a coordinated and transparent process.

FERC Order 1000 on Transmission Planning and Cost Allocation

FERC Order 1000 on "Transmission Planning and Cost Allocation" was issued on July 21, 2011. The order includes mandates that require utilities and RTOs to prepare and submit compliance

[5] Interstate has been reassessed and its need has been reconfirmed by ISO-NE. Previous IRP decisions have also discussed this project.

[6] Project is being reassessed as part of GHCC Study.

[7] Project is a line approximately two miles long.

filings. The State, along with other stakeholders, is helping ISO-NE to develop this compliance filing. Specific requirements included in Order 1000 are summarized below:

- Each public utility transmission provider participates in a regional transmission planning process that produces a regional transmission plan.
- Each public utility transmission provider amends its tariff to describe procedures that provides for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes.
- Removes from Commission-approved tariffs and agreements a federal right of first refusal for certain new transmission facilities.
- Seeks to improve coordination between neighboring transmission planning regions for new interregional transmission facilities.
- Each public utility transmission provider must participate in a regional transmission planning process that has: (1) a *regional cost allocation* method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation; and (2) *an interregional cost allocation* method for the cost of certain new transmission facilities that are located in two or more neighboring transmission planning regions and are jointly evaluated by the regions in the interregional transmission coordination procedures.

ISO-NE and New England Power Pool (NEPOOL) are currently reviewing New England planning processes for compliance with other elements of FERC Order 1000 requirements. Preliminary review of the requirements of Order 1000 suggests existing processes in New England already comply with many of these requirements. These include the following:

- ISO NE already conducts and publishes annually a 10-year outlook regional system plan (RSP).
- ISO-NE has a regional cost allocation formula for transmission facilities.
- ISO-NE incorporates public policy of demand response, State energy efficiency programs, the Regional Greenhouse Gas Initiative (RGGI), and Environmental Protection Agency (EPA) orders in transmission planning.

Minimum Offer Price Rule (MOPR) Relationship to NTAs

In April of 2011, the FERC rejected ISO-NE's proposed revisions to the Alternative Price Rule and requested that ISO-NE develop a MOPR for new resources, similar to the one the FERC had just ordered for PJM. ISO-NE has since issued its compliance filing, but the FERC has not yet issued its order and some of the implementation details have not been fully established. MOPR will affect the price at which new resources can enter the forward capacity market. Based on the FERC order rejecting ISO-NE's APR filing, it appears that a new MOPR could make NTA contracting risky for the state. Resources selected to serve reliability needs might be considered

"subsidized" and thus might be subjected to a minimum offer level that might not clear, unless the special value an NTA provides is somehow recognized as an additional revenue source lowering the net cost of the unit.

Eastern Interconnection Planning Collaborative (EIPC)

The EIPC is a first ever effort to involve Planning Authorities in the entire Eastern Interconnection to analyze the impact of various energy policy options determined to be of interest by state, provincial, and federal policy makers. The EIPC received funding of $16 million from the U.S. DOE in 2010 to initiate a multi-sector stakeholder and transparent collaborative transmission planning process.

The State Regulators of 39 Eastern Interconnection states participate in the EIPC through the Eastern Interconnection States Planning Collaborative (EISPC) where the DOE also provided funding of $14 million. The EIPC was initiated by a coalition of 26 planning authorities across the Eastern Interconnection, including ISO-NE as a Principal Investigator.

The Stakeholders represented in the EIPC include state regulators, federal government, transmission owners, generators, other suppliers, end users, other suppliers, non-governmental organizations (NGOs), and Canada.

The EIPC project is split into two phases, Phase I and Phase II. In Phase I, policy makers and stakeholders derive futures based on policy inputs and then select three transmission scenarios. In Phase II, the three transmission scenarios from Phase I are then studied for basic reliability and production cost modeling.

The types of public policies that are considered in the EIPC are renewable portfolio standards, carbon policy, energy efficiency, EPA regulations, and others. The EIPC considers cases in which these policies are implemented at the national level or at the regional level where neighboring regions work together.

EIPC has identified the following eight (8) futures during Phase I:

1. Business as Usual
2. National Carbon Policy
3. Regional Carbon Policy
4. Aggressive EE/DR/DG/DSM
5. National RPS policy
6. Regional RPS Policy
7. National Combined Energy
8. Climate Policy

These eight futures were modeled in a proprietary capacity expansion economic model simulation tool, and base line simulations were constructed. EIPC also has explored 72 sensitivities in variable projections such as fuel prices, demand growth, policy parameters, lower capital costs of renewables, imports from Canada, and others.

Through the stakeholder process, the EIPC selected three transmission scenarios as the output of Phase I to be studied in Phase II. The three transmission scenarios are (1) business as usual (BAU), (2) regional Renewable Portfolio Standards, and (3) national combined energy and climate policy. The EIPC Phase I report was released in December, 2011.[8]

The EIPC has set an example of how to translate public policy issues into potential transmission plans. During 2012, EIPC will conduct the Phase II study. ISO-NE, as a collaborator in the EIPC process, will assist in developing conceptual transmission projects for New England.

[8] See http://www.eipconline.com/uploads/Phase_1_Report_Final_12-23-2011.pdf.

APPENDIX H

EMERGING TECHNOLOGIES

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INTRODUCTION

New technological advances have the potential to change Connecticut's resource planning landscape. Specifically, there are several technologies with limited impact on resource planning today, but which may take on increasing importance over the coming decade. It is valuable to understand the possible influence of these technologies, particularly to the extent that state-level activities could help to optimize their role in Connecticut's future portfolio of energy resource options.

A diverse group of IRP team members identified three technologies that are most likely to play an increasingly important role in resource planning over the coming decade:

- Advanced metering infrastructure (AMI)
- Plug-in electric vehicles (PEVs)
- Energy storage

For each of these three technologies, we address five key questions that the IRP sub-group identified as being of particular interest:

- What is the current state of the technology (*e.g.*, performance and cost)?
- What is the technology's current and future deployment status in the U.S.?
- What is its current and future deployment status in Connecticut?
- What are the barriers to further adoption of the technology?
- What state-level activities can help to overcome these barriers?

Two additional technologies were also considered due to interest among state policy-makers. These technologies have lower impact potential or a higher degree of adoption uncertainty in Connecticut, so they are discussed to a more limited degree:

- Geothermal energy
- Advanced waste-to-energy (AWE)

ADVANCED METERING INFRASTRUCTURE (AMI)

AMI represents an upgrade to the metering system that allows for digital two-way communication between the utility and the meter (and ultimately the customer). This enables the utility to remotely collect granular electricity consumption data from each meter measured in short time intervals (*e.g.*, every 15 minutes). This functionality has a number of operational benefits, including avoided meter reading costs, remote connect/disconnect capability, faster outage detection, and improved load research and forecasting.

In addition to these operational benefits, AMI also allows a number of new services to be offered to the customer, which allows customers to better manage their energy use. By reducing or

shifting their electricity consumption, customers will have the opportunity to lower their bills and utilities will be able to defer or avoid resource investment costs.[1] The new AMI-enabled services include:

- **Innovative rate designs**, such as time-of-use rates or dynamic rates, which more accurately reflect the true cost of providing power over the course of the day.
- **Enhanced energy information**, which provides customers with granular and actionable information about their electricity consumption.
- **Advanced load control**, which includes technologies that help customers automatically reduce electricity consumption during high-priced hours.

Of course, capital must be invested in the AMI system to enable these benefits. Roughly half of the cost of AMI is typically associated with metering equipment and installation. The remaining costs are due to a number of elements such as IT and communications system upgrades, customer education and outreach, and project management.

AMI Deployment in the United States

AMI is being deployed to varying degrees around the United States. Currently, roughly 13% of all meters are considered "advanced."[2] By 2015, it is anticipated that deployment will grow to 65 million meters, representing roughly half of all U.S. households.[3] In some cases, the impetus for deploying AMI has originated with utilities. For example, ComEd recently fought for (and won) approval of its proposed AMI investment in the Illinois state legislature. In other cases, AMI deployments have been mandated by the state (such as Pennsylvania's Act 129, which requires statewide deployment). The projected market penetration of AMI is summarized by state in Figure 1.[4]

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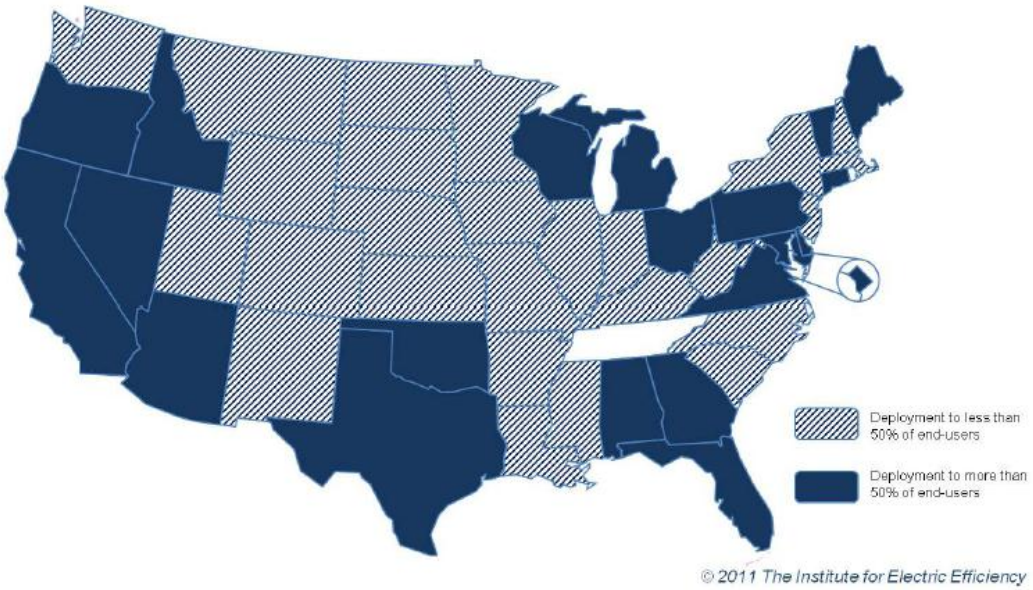
1 Ahmad Faruqui, Ryan Hledik, and John Tsoukalis, "The Power of Dynamic Pricing," *The Electricity Journal*, April 2009.

2 FERC, "2011 Assessment of Demand Response & Advanced Metering," Staff Report, November 2011.

3 Institute for Electric Efficiency, "Utility-Scale Smart Meter Deployments, Plans & Proposals," September 2011.

4 Note that the figure projects deployment to more than half of end-users in Connecticut. We find it unlikely that AMI deployment will reach that level in the state by 2015, as discussed in the next section of this appendix.

Figure 1: Utility Smart Meter Deployments, Plans, and Proposals



One reason for the recent increase in AMI investment is that equipment costs have come down to economic levels over the past decade. While the cost of deploying AMI is system-dependent and can vary greatly by utility, recent EPRI research finds that the average total cost of deployment across the U.S. could range roughly between $100 and $300 per meter.[5]

Utilities have demonstrated that the benefits of AMI can significantly outweigh the costs. Some AMI deployment proposals have justified the cost of investment purely on the basis of operational benefits. In these instances, the cost savings — such as reduced meter reading costs and remote connection and disconnection of service — produced a positive net present value over the expected life of the deployment. Operational savings are greatest for utilities that are replacing a metering system that requires the meters to be read manually. In cases where utilities already have automated meter reading (AMR), these operational benefits are smaller.

Other approved AMI deployments have relied on the benefits of new customer programs to make up the "gap" between investment costs and operational savings. Typically, the bulk of these benefits are derived from avoided generating capacity costs due to peak load reductions from mass market dynamic pricing. Energy cost savings, transmission and distribution (T&D) cost savings, and wholesale market price reductions are sometimes also quantified by utilities as benefits.

AMI Deployment in Connecticut

Public Act No. 07-242 required each electric distribution company in Connecticut to submit a plan for deploying AMI by July 2007. In response to this requirement, AMI proposals were

[5] Based on an average nationwide mix of residential and C&I customers; includes installation and ongoing maintenance costs. See EPRI, *Estimating the Costs and Benefits of the Smart Grid*, March 2011, page 6-13.

developed by both CL&P and UI. UI's proposal was approved in March 2008 and a system-wide upgrade to AMI is currently underway. In CL&P's case, PURA issued a preliminary draft decision in which it recommended to defer CL&P's proposal, with the possibility of re-filing at a later date once there is more certainty in industry standards and the state of the technology. DEEP is currently examining the development of national smart metering standards and best-practices across the country, and expects to issue a policy recommendation in the next several months. For information on the current state of smart metering standards, see the sidebar at the end of this section.

The UI Business Case

Before its 2007 AMI filing, UI already had a metering system with remote data collection, which it had installed in 1998. However, unlike AMI, the system did not support two-way communication and was not equipped to handle hourly meter data. Therefore, UI's 2007 AMI filing was essentially for an upgrade to its IT, billing, and communications systems, without a large equipment cost component.

UI's proposal was approved in March of 2008, and UI has been executing that plan in a controlled and well-structured approach. The individual components of the plan are executed in sequence and only when the systems and support infrastructure are in place so as to maximize the technology, the investment, and the benefits and avoid any costly rework. UI currently is replacing only a small percentage of its meters with advanced meters and replacing on an as needed basis or with known benefits to consumers, suppliers, and regulators. Over time, many of UI's aging meters will be replaced but on a cost effective and as needed basis.

While UI's new system has full remote meter reading capability and is reported to be capable of handling new and innovative rate designs, UI recognizes that there could be additional benefits to replacing the existing meters with more advanced technology. These benefits include remote connect/disconnect, advanced event logging including power outages utilized in service restoration during storms, voltage monitoring, over the air firmware and program updates, enabling advanced rate design and net energy metering, and the ability to enable in-home technologies like home area networks (HAN). UI currently offers TOU rates, in which 29% of its residential load and 63% of its C&I load are enrolled.

Roughly 80,000 of UI's 337,000 total meters have been replaced with advanced meters. This measured approach to the meter change is by design and helps reduce overall costs, provides realizable benefits, and continues to meet the future needs of customers and regulators.

The CL&P Business Case

CL&P proposed an upgrade to AMI from an automated meter reading (AMR) system once the necessary standards were in place. AMR allows for efficient collection of meter data through wireless signals. However, data is not automatically communicated back to the utility. Rather, it must be collected by crews who get within close range of the meter by driving by and collecting the data through a receiver. As such, CL&P's filing required a more costly full-system replacement rather than an "enhancement" to the existing system. The cost of the investment

was estimated by CL&P at $429 million, or roughly $360 per customer.[6] Benefits would be driven partly by operational savings, but more significantly by the impacts of voluntary dynamic pricing programs for residential and C&I customers (with an assumed participation rate of 25%). Benefits were estimated to outweigh costs by a ratio of 1.4-to-1.[7]

In a preliminary draft decision in August 2011, PURA deferred CL&P's business case on the basis that the benefits were uncertain and considered to be overstated in some instances. PURA also cited technological uncertainty and a need for more established AMI standards before CL&P should aggressively deploy the technology to all customers.

Barriers to Deployment

There are barriers not only to future AMI deployment in Connecticut, but also to the deployment of new customer programs that would affect future resource planning efforts

Uncertain benefits: Regulators express concern that the benefits of AMI will not materialize (*e.g.*, impacts of dynamic pricing will not persist over time or will not scale proportionally from pilot results when fully deployed). Stakeholders also question whether it will be possible to fully monetize these impacts.

Security, privacy, and interoperability concerns: The availability of more granular meter data represents a risk of loss of privacy to some consumer groups. Security risks associated with AMI database hacking or careless data management are also a concern. Additionally, uncertainty around interoperability standards has slowed the deployment of AMI in some regions, including Connecticut.

Customer resistance: Some AMI deployments have faced stakeholder resistance during implementation. Some concerns relate to the health effects of wireless communications systems. Other concerns have related to accuracy of the meters. Both have been investigated and found not to be problematic, although some states (such as Maine and California) give customers the option to opt out of a smart meter installation at an incremental cost.

Regulatory uncertainty: Utilities are hesitant to deploy AMI if there is uncertainty around how or when they will be able to recover the costs.

Technological uncertainty: While the deployment of over 10 million smart meters nationally suggests that technological uncertainty is becoming less of an issue, there is still regulatory concern regarding whether new meter deployments will too quickly become obsolete (*e.g.*, the "Betamax" problem).

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[6] Note that this the present value of the total cost, including O&M and customer engagement costs. Capital cost is $257 million of this amount.

[7] PURA Draft Decision in Docket No. 05-10-03RE4, dated August 29, 2011.

Stranded costs: Stranded costs can adversely affect the economics of an AMI business case to the extent that the smart meters are replacing equipment with significant remaining useful life.

Addressing the Barriers

There are several options for addressing the barriers to cost-effective AMI deployment, many of which can be implemented at the state level. These activities have the potential to accelerate the pace at which AMI-enabled programs could begin to impact resource planning.

Gain additional statewide familiarity with benefits of customer programs: A wide range of pilots and programs have demonstrated that the impacts of dynamic pricing, automated load control, and enhanced information provide persistent and significant impacts. A detailed review of these studies, or additional smart grid piloting in Connecticut, could help to reduce the uncertainty surrounding the benefits of AMI.[8]

Provide protections for specific customer sub-segments: Policies can help to address concerns related to bill increases for certain sub-segments such as low-income and elderly customers. There may also be a desire to implement protections against remote disconnect for those customers with critical medical devices that cannot be interrupted. Policies to address these issues — such as temporary bill protection — are being considered in other states as they transition to the smart grid.[9]

Support expanded customer education plans: Education and outreach plans can enhance customer acceptance and increase participation in AMI-enabled programs. The provision of a detailed and well-defined customer education plan before deployment could help to address concerns over acceptance.

Ensure shared risk in cost recovery: To address uncertainty as to whether the projected benefits of AMI will materialize, cost recovery mechanisms can be established in a way that share risk between the utility and ratepayers. Clear and definitive guidance on the acceptable methods for recovering costs in Connecticut to help reduce related uncertainty for the utilities.

Require expanded dynamic pricing deployment: The benefits of AMI deployment increase at little incremental cost as additional customers participate in dynamic pricing. Offering dynamic pricing as the default tariff (rather than on an opt-in basis) is one way to achieve higher levels of enrollment.

Support provision of enhanced energy information through open data access: To fully unlock the information-related benefits of AMI, standards could be established to allow access to the meter data by third parties. This would enable a competitive market for new consumer products. To ensure an acceptable level of data privacy, standards could be modeled after those of other

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8 Ahmad Faruqui and Jennifer Palmer, "Dynamic Pricing and Its Discontents," *Regulation*, Fall 2011.

9 Lisa Wood and Ahmad Faruqui, "Dynamic Pricing and Low Income Customers," *Public Utilities Fortnightly*, November 2010.

states such as California and Texas that have dealt with this issue through formal regulatory proceedings.[10]

Gain Practical Experience through a Pilot Project

Pursuant to Governor Malloy's Two Storm Panel Review and ongoing efforts for Connecticut to address storm disaster preparedness and recovery, DEEP will undertake a pilot program for the deployment and funding of distributed generation and microgrids, combined with smart grid technology at critical facilities (such as hospitals, prisons, and sewage treatment plants) and in city centers, as well as the use of energy improvement districts as a mechanism to support microgrids. Through this pilot program DEEP hopes to further evaluate how implementation barriers can be overcome.

[10] See, for example, California Public Utilities Commission Proceeding R0812009.

THE CURRENT STATUS OF U.S. SMART METERING STANDARDS

As required by the Energy Independence and Security Act of 2007, the National Institute of Standards and Technology (NIST) is overseeing the development of smart grid interoperability standards in the U.S. To lead this specific effort, NIST created the Smart Grid Interoperability Panel (SGIP).[11] The SGIP is comprised of over 700 member organizations and involves the participation of more than 1,800 individuals. The SGIP has several working groups that are assigned to deal with a range issues in the development of smart grid standards, primarily the interoperability of smart grid technologies and the security of the smart grid system. The standards address smart metering, but are not limited to this technology. They also address many other aspects of the "smart grid," such as transmission and distribution automation, electric vehicles and distributed generation and storage.

Over the past three years, NIST has made significant progress in developing smart grid standards. NIST brought together industry stakeholders to initiate the development of these standards beginning in 2008. By January 2010, NIST released the conclusions of the first phase of these activities in a document titled *NIST Framework and Roadmap for Smart Grid Interoperability Standards (Release 1.0)*. The document served as a high level conceptual reference model and identified 75 standards that would likely be applicable to the ongoing development of the smart grid. However, this was just the first step in a continuing series of related activities. The working groups have continued to meet regularly. Very recently, in October of 2011, NIST released a draft version 2.0 of its *Framework and Roadmap for Smart Grid Interoperability Standards*.[12] This included updated, refined, and expanded versions of the original standards, filling in gaps that had been left in the first version of the document. The document was open to public comment up until late November of 2011, and the SGIP is currently working to resolve the comments.

NIST's work is ongoing. Moving forward, the framework document will continue to be subject to further refinement, expansion, and new releases. The development of smart grid standards is an evolutionary process that must remain flexible as new challenges arise in a rapidly changing environment. Future changes will come through what are called "Priority Action Plans."[13] These are created to address any unresolved or emerging issues. Currently, there are three active Priority Action Plans related to smart metering. They are focused on developing a common format for smart meter data reporting and on developing standards for communication between smart meters and consumer devices (*e.g.*, electric vehicles and distributed generation).[14] These Priority Action Plans were scheduled to be concluded near the end of 2011, although no public information on their findings appears to be yet available.

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[11] For more information on the SGIP: http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/WebHome

[12] The document can be found here:
http://collaborate.nist.gov/twiki-sggrid/pub/SmartGrid/IKBFramework/Draft_NIST_Framework_Release_2-0_10-17-2011.pdf

[13] A description of the Priority Action Plans: http://www.nist.gov/smartgrid/plans.cfm

[14] FERC, Assessment of Demand Response and Advanced Metering, November 2011, p. 4.

PLUG-IN ELECTRIC VEHICLES

The concept of a plug-in electric vehicle (PEV) is neither a new technology nor new to the state. One of the first electric vehicles, the Pope vehicle was first manufactured in Connecticut in the 1800s. However, challenges with this technology, including a relatively limited driving range, long recharging times, and high initial costs, have combined to impede the growth of PEVs from capturing significant market interest or penetration until recently. With the introduction of plug-in hybrid vehicles and advancements in the battery technology that increase the amount of power that can be stored in a vehicle battery, PEV adoption is finally starting to take off. This industry has also targeted Connecticut as an early market for PEVs as a result of efforts in the state undertaken by government leaders, environmentalist, regulators, and the utilities to promote the significant benefits related to alternative vehicles.

Current State of Technology

There are two main types of plug-in electric vehicles. A battery electric vehicle is powered entirely by battery power and generally characterized as an all-electric car. Plug-in hybrid electric vehicle (PHEV), on the other hand, combines grid-chargeable electric motors with internal combustion engines. A PHEV is essentially a gasoline electric hybrid vehicle with a much larger battery that can be plugged into the electric grid for charging. Figure 2 compares general characteristics of the battery electric and plug-in hybrid electric vehicles.

Figure 2
General Characteristics of Battery Electric and Plug-in Hybrid Vehicles[15]

Battery Electric Vehicle		Plug-in Hybrid Electric Vehicle
	Drivetrain	
~100 miles	**Electric Range**	15 – 40 miles
Commuting, fixed routes, short routes, etc.	**Driving Patterns**	Irregular driving patterns, highway driving, long routes
Purists, principled, making statement, technology driven, 2nd vehicle, etc.	**Expected Profile of Vehicle Owners**	Primary vehicle, pragmatic consumers, expect same performance, no loss of convenience, etc.
Level 2 and DC Fast Charging	**Recharging Equipment Sizes**	120 v outlets and Level 2
Home, work & public	**Recharging Locations**	**Home** & work

Charging characteristics of the PEVs have important implications for the adoption rate of these vehicles. Most residential and public charging currently occurs at power levels ranging from 1 kW to as much as 19.2 kW at full charge times of three to eight hours.[16] Currently, there are three commercially available charging options:

Level 1 AC charging: It delivers 120 Volts through electric vehicle supply equipment (EVSE) that consists of a self-contained cable and plug. It is compatible with any standard 120 Volt household outlet and generally is limited to 1.44 kW. Under Level 1 charging, fully charging a Chevrolet Volt takes 8-10 hours, while fully charging a Nissan Leaf takes 20-24 hours.

Level 2 AC charging: It delivers 240 Volts through an EVSE that is hard-mounted on a wall and supplied by its dedicated circuit. The power level can reach 19.2 kW, with most installations using power levels in the range of 3.3 kW to 6.6 kW. Current residential installation costs range from $500 to a few thousand dollars.

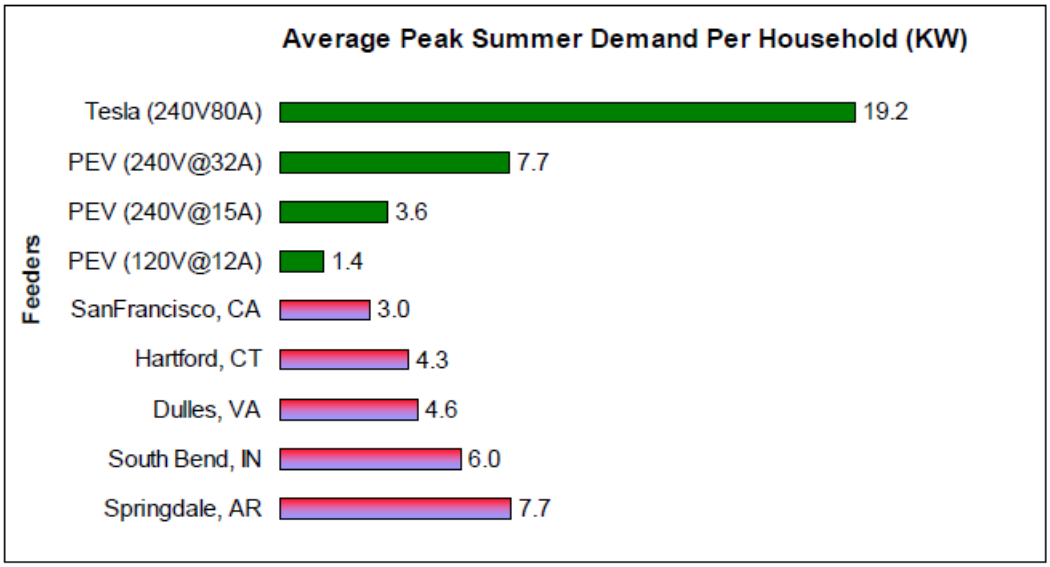
DC Fast charging: It uses an off-board charging station to convert AC power to DC and directly charge the vehicle battery without the need for an onboard charger. DC Fast charging can reach power levels in the range of 50-60 kW. DC Fast charging is intended primarily for public and commercial fleet applications. Moreover, DC Fast charging standards have not been finalized yet.

[15] Reproduced from "Plug-in Vehicles," Watson Collins, NU, Presented at Emerging Technologies Stakeholder Meeting, October 17, 2011.

[16] EPRI, "Transportation Electrification: A Technology Overview," 2011 Technical Report.

Different charging options have different implications for the demand they impose on the electric system. Figure 3 presents the increase in the average household summer peak demand under Level 1 and Level 2 charging options. Level 2 charging with an 80 amp circuit will have a much larger impact on the local distribution system than the Level 1 charging with a 12 amp circuit.

Figure 3
Impacts of the Level 1 and Level 2 Charging on the Average Household Summer Peak Demand[17]



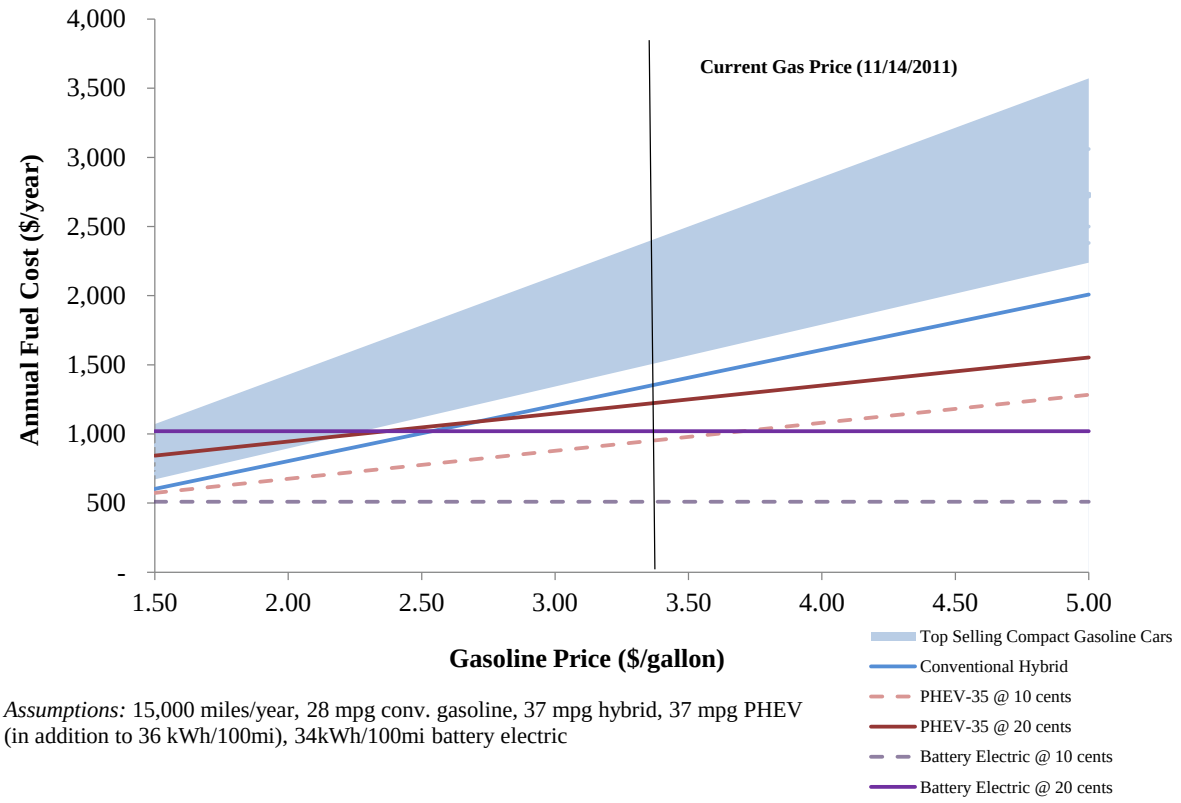
Currently, there are five different charging infrastructure models: (i) municipally-owned and operated for public benefit; (ii) utility-owned and operated for public benefit; (iii) employer-owned and operated for employee benefit; (iv) privately-owned to enhance customer service quality (*e.g.*, stations installed at malls and theaters); and (v) privately-owned and operated for commercial purposes. In addition to these public and commercial models, individuals can own and operate EVSEs at their premises. In fact, several studies estimate that 70 to 80% of the charging will occur at customer premises.

There are several factors that influence PEV purchase decisions. Some of these are based on individual preferences such as the appeal of a car and/or environmental concerns. Others are based on the economics of owning a PEV versus a conventional gasoline-fueled car and may include the initial purchase price of the car, annual fuel costs, electricity prices, and battery life. Figure 4 illustrates how the total annual fuel costs may affect the PEV purchase decision. We identified eight top selling gasoline-fueled cars (fuel economy varied, but averaged 28 miles per gallon) and calculated the corresponding range of annual fuel costs shown by the shaded blue area in the figure. When we compare this shaded blue area to the battery electric and PHEV fuel costs, we see that it is typically less expensive (by roughly $500 to $1,000 per year) to operate a vehicle on electricity than on gasoline. The extent of fuel cost savings from a PEV car will depend on relative energy prices (*e.g.*, higher gasoline prices will increase the savings, while

[17] *Ibid.*

higher electricity prices will reduce them) as well as other assumptions about vehicle performance and usage patterns.

Figure 4
Illustrative Cost Comparison of Conventional Gasoline Fuel Cars and PEVs

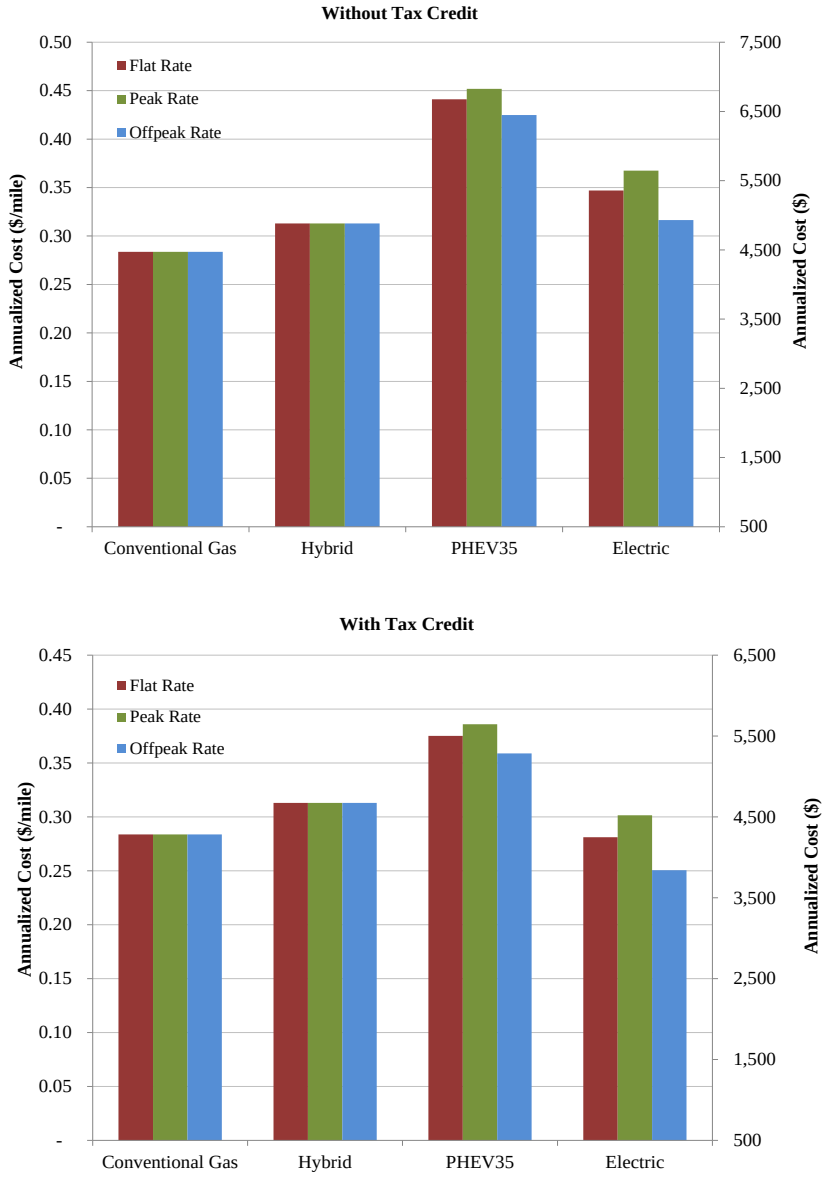


Assumptions: 15,000 miles/year, 28 mpg conv. gasoline, 37 mpg hybrid, 37 mpg PHEV (in addition to 36 kWh/100mi), 34kWh/100mi battery electric

In addition to comparing total annual fuel costs across conventional gasoline fuel (CGF), hybrid, PHEV, and battery electric cars, we also compared the annual all-in costs (which include the initial cost of the car, maintenance expenses, and fuel costs) of owning these cars in Figure 5. Under a base gasoline price scenario ($3.43/gallon), the annual all-in-cost of owning a CGF car is less than those of the other options assessed in our analysis. This observation holds true for three different electricity rate assumptions (flat rate: $0.16/kWh, peak rate: $0.22/kWh and off-peak rate: $0.07/kWh) employed in our analysis. This result is mostly driven by the large premium included in the initial purchase costs of the battery electric and PHEV cars. The picture for PEVs improves quite a bit when we assume a $7,500 federal tax credit that effectively reduces the initial cost of purchasing a PEV. In this case, battery electric cars become quite comparable to the CGF cars; in fact their all-in cost is lower under the off-peak rate assumption compared to that of the CGF cars. A tax credit reduces the cost difference between the PHEV and CGF cars, but it is not sufficient to bridge the gap entirely.[18]

[18] Purchase price and tax credit impacts are annualized assuming an annual interest rate of 5.4%.

Figure 5
Comparison of Annual All-in Costs under Base Gasoline Price Scenario

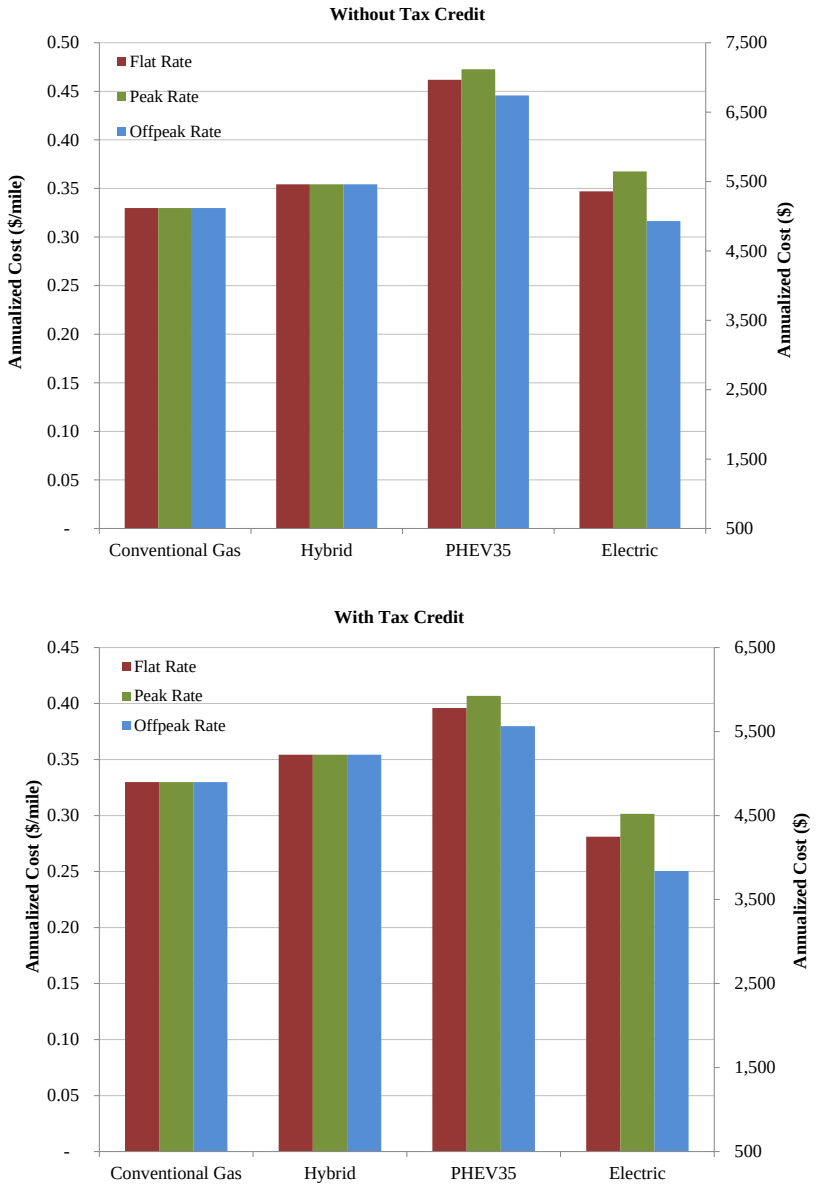


Assumptions:

1- 15,000 miles/year, Flat rate: 0.16 $/kWh, Peak Rate: 0.22 $/kWh, Offpeak Rate: 0.07 $/kWh.
2- **Conventional Gas**: Honda Civic, **Hybrid**: Toyota Prius, **PHEV 35**: Chevy Volt , **Electric**: Nissan Leaf

Figure 6 presents the similar results under a high gasoline price scenario ($4.97/gallon). In this scenario, the all-in cost of owning a battery car gets very close to that of the CGF car. In fact, if the charging is done using an off-peak rate, the all-in cost is even lower than that of the CGF car. When we bring in the tax credit in the high-gas scenario, the all-in cost of the battery car is substantially less than that of the CGF car (under all rate scenarios). The PHEV costs also get quite close to the CGF costs, but they are still higher under all rate scenarios.

Figure 6
Comparison of Annual All-in Costs under High Gasoline Price Scenario



Assumptions:

1- 15,000 miles/year, Flat rate: 0.16 $/kWh, Peak Rate: 0.22 $/kWh, Off-peak Rate: 0.07 $/kWh.
2- **Conventional Gas**: Honda Civic, **Hybrid**: Toyota Prius, **PHEV 35**: Chevy Volt , **Electric**: Nissan Leaf

Likely PEV Penetration in the United States

There are several benefits of the increased PEV adoption from a societal perspective. To the extent that the gasoline-fueled cars are largely replaced by the PEVs, PEVs will lead to less dependence on imported fossil fuels; reduced greenhouse gas emissions and local pollution; better utilization of off-peak generation capacity; and improved system load factors. The adoption of PEVs depends partly on the relative economics compared to conventional vehicles,

as well as performance, customer acceptance, and concerns on energy security and climate change. Depending on how each of these factors may evolve, projections for future penetration vary widely. To capture this uncertainty, EPRI developed three scenarios to project the likely PEV adoption between 2010 and 2030:

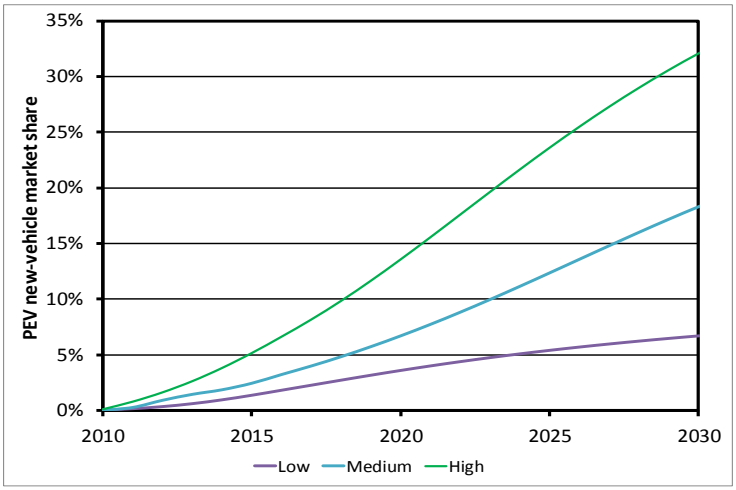
- *Low Scenario* is primarily driven by the hybrid electric vehicle (HEV) sales performance from 2000 to 2008 and projected to 2030. According to this scenario, the PEVs will take 3% and 7% of the new vehicle market share respectively in 2020 and 2030.
- *Medium Scenario* is based on HEV sales combined with the announced manufacturer plans for PEV production volume. According to this scenario, the PEVs will take 6% and 18% of the new vehicle market share respectively in 2020 and 2030.
- *High Scenario* is an optimistic scenario that reflects the development of one or more factors that significantly favor PEV adoption. According to this scenario, the PEVs will take 13% and 30% of the new vehicle market share respectively in 2020 and 2030.

Likely PEV Penetration in Connecticut

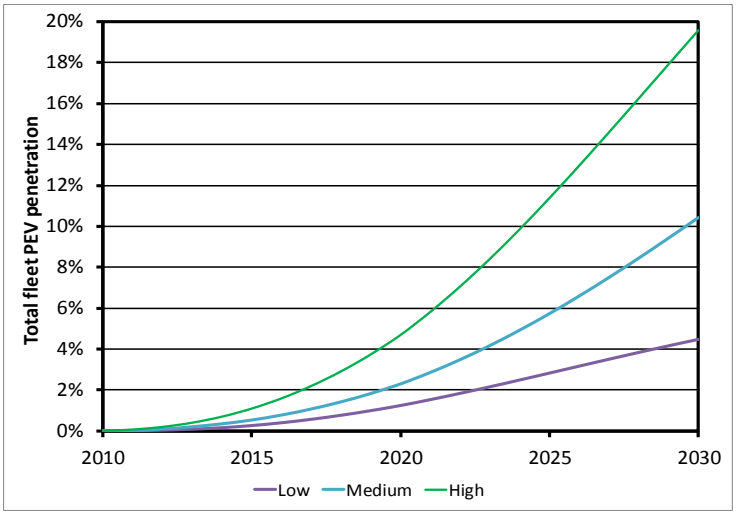
EPRI projected the likely PEV penetration for Connecticut as well, using the three scenarios described above. Based on the *low scenario*, PEVs will take 4% and 7% of the new vehicle market share respectively in 2020 and 2030. Based on the *medium scenario*, PEVs will account for 7% and 16% of the new vehicle market share respectively in 2020 and 2030. Based on the *high scenario*, PEVs will account for 14% and 32% of the new vehicle market share respectively in 2020 and 2030. Figure 7 presents EPRI's projections for new fleet market share, total fleet market share, and cumulative number of PEVs in Connecticut between 2010 and 2030.

Figure 7

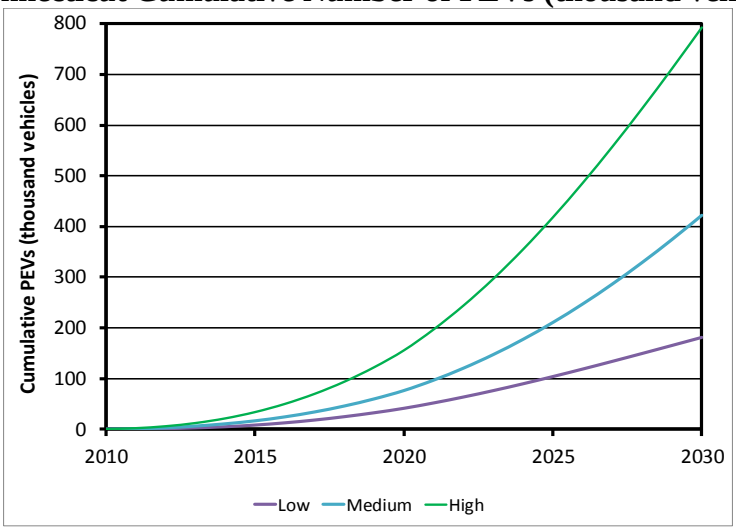
1. Connecticut PEV *New Vehicle Market* Share Forecast



2. Connecticut PEV *Total Fleet Market* Share Forecast



3. Connecticut Cumulative Number of PEVs (thousand vehicles)



Existing PEV Initiatives in Connecticut

In 2009, Connecticut's Electric Vehicle Infrastructure Council, a collaborative effort between government and private entities, was convened to help prepare the state for rapid and seamless integration of PEVs into the market. In 2010, the final report of the Electric Vehicles Infrastructure Council proposed a goal of 25,000 electric cars statewide by 2020. The EV council also developed five strategic priorities: (i) early access to the first wave of mass-produced PEVs; (ii) enacting legislation for offering tax incentives/grants; (iii) building statewide PEV charging infrastructure through a partnership between public and private entities; (iv) developing a regulatory framework to address the pricing of charging and infrastructure options; and (v) working with neighboring states to develop a regional corridor for access to public charging stations.

Connecticut EDCs also have been actively studying the implications of increasing PEV adoption and preparing for a future with large numbers of PEVs on the roads. CL&P established early positive relationships with automakers to encourage availability of the vehicles in CT. It planned PEV pilot programs to understand the charging patterns under time-based pricing and conducted charging equipment demonstration pilots. In collaboration with EPRI, CL&P developed a forecasting model to predict PEV penetration, concentration, and distribution system demand scenarios. Similarly, UI installed a network of public and residential charging stations to collect information on installation costs and consumer charging behavior. It has been analyzing the data from these charging stations to design a DSM program offer to the customer, in which the cost of the charging stations and installation and maintenance costs would be paid through monthly payments over the life of the equipment. UI also worked with a consultant to predict distribution demand scenarios. Both EDCs are actively engaged in collaborations with neighboring states and utilities to promote PEVs.

Impact on the Generation System

The likely increased PEV penetration warrants a careful assessment of grid conditions and distribution capacity to serve these new loads. While some believe that simultaneous charging of PEVs at system peak could result in supply shortages, generation capacity shortages are not very likely over the next ten years.

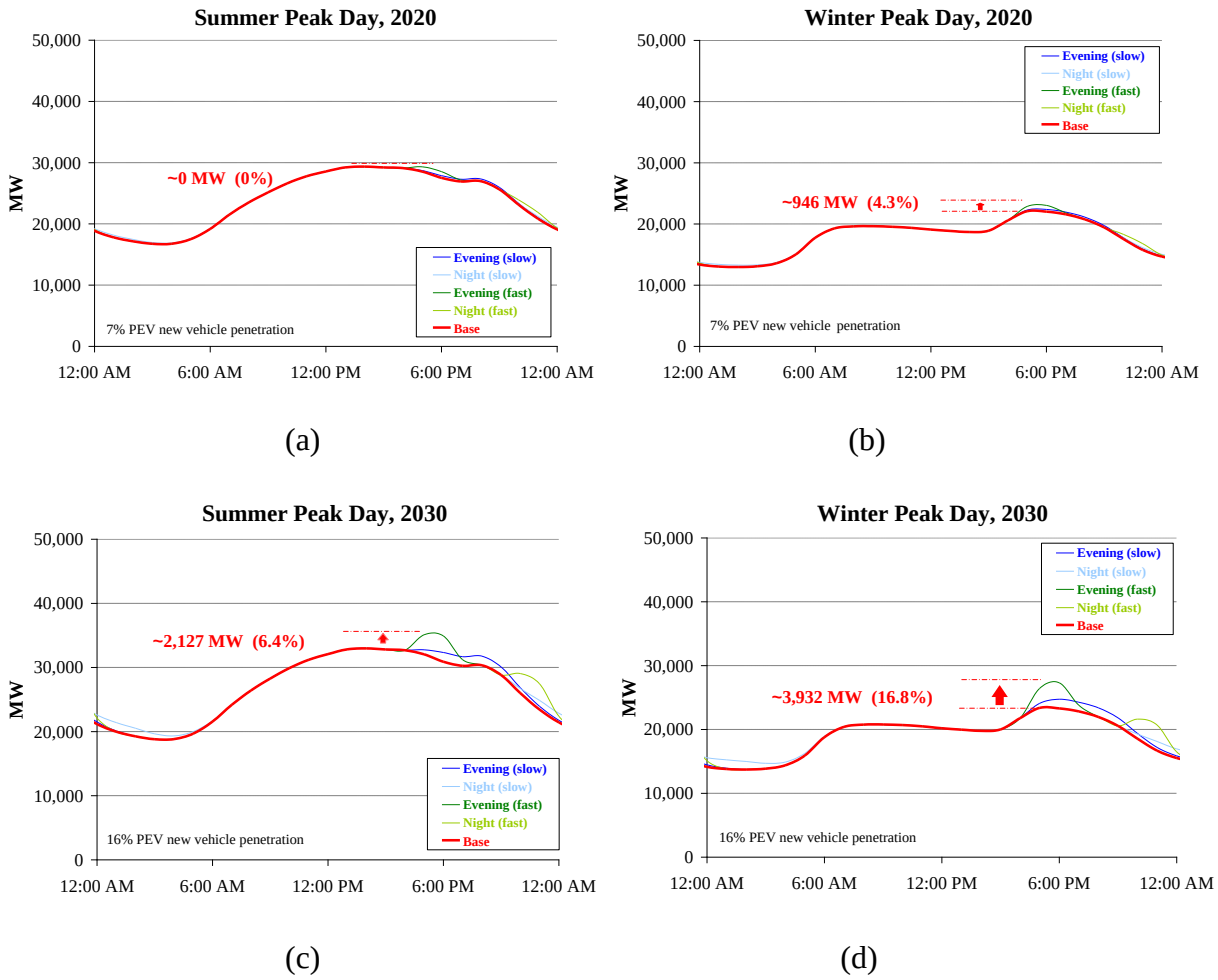
It is expected that about 80% of PEV charging will take place in the homes of PEV owners, when the cars are parked overnight. It is often assumed that the vehicle charging could create a large coincident load with peak. However, according to a recent EPRI research, at any given time, only a maximum of 12% of people will have arrived at their homes and begin charging.[19] This implies that all vehicles *will not* be connected at the same time. As long as this behavior can be sustained and the charging happens during off-peak periods, Connecticut's current generation capacity is more than sufficient to meet increased PEV load.

However, this report also discusses an extreme scenario to investigate the impact of the additional load implied by EPRI's medium penetration scenario, on top of New England system loads during summer and winter peak days, for 2020 and 2030. Four different alternative

[19] *Ibid.*

scenarios of PEV charging loads are overlaid on this — charging is either fast or low, and starts either in the evening (5-6 pm) or at night (10-11 pm). This scenario assumes that all customers start charging at the same time making this an extreme scenario. Figure 8 presents the results.

Figure 8
Potential Impact of Added PEV Demand on New England System Load



The peak impacts for 2020 are negligible, because the cumulative number of New England PEVs is still relatively low at about 260,000 vehicles in 2020 driven by EPRI's medium scenario. In fact, there is no impact on the summer peak load in 2020, as the summer peak load is expected to occur at 2 pm, and the PEV charging does not start until 5 pm. There is some impact on the winter peak load, as the winter peak load is expected to occur at 5 pm and is coincident with the PEV charging. Fast evening charging has the biggest peak effect, since it concentrates the PEV load over just a couple of hours at or near daily peak. This admittedly extreme scenario could add 946 MW to winter peak in 2020, and in 2030, could add as much as 2,127 MW summer and 3,932 MW winter.

Alternatively, if PEVs charge later at night, and/or spread their loads over a longer period, the effect on system peak can be reduced or even eliminated. If it were possible to shift the entire PEV load into the off-peak period, even more significant PEV loads can be accommodated

without any effect on system peak, improving system load factors. It is technically possible to motivate this behavior by pricing (*e.g.*, time-based rates) and technical (*e.g.*, managed charging) incentives; however pilot programs are needed to verify these solutions. The reality will probably fall in between these two cases: it is highly unlikely that all PEVs will charge on the same schedule but some owners will undoubtedly charge PEVs during peak load hours regardless of the incentives. It is DEEP's expectation that the gradual increase in the number of vehicles and understanding the charging patterns will allow orderly pacing of new investments required to adapt to increased demand.

Impact on the Distribution System

Although the increased penetration of the PEVs is not likely to impact the generation system materially at least in the next ten years, local distribution system impacts can materialize even before penetration levels percentages reach to very high levels. Coincident charging of several PEVs that are connected to the same distribution circuit can quickly overload the local feeders and transformers.

EPRI recently conducted a detailed analysis of the potential load impacts on actual distribution circuits.[20] Results show that: (i) diversity of vehicle location and charging time will minimize the impact on the distribution systems; (ii) level 1 charging generates the fewest distribution system impacts; (iii) level 2 charging generates the most severe impacts, but it is not typically required for most customer charging scenarios; (iv) short-term PEV impacts for most utility systems are likely minimal and restricted to smaller transformers where the existing capacity per customer is already low; and (v) managed charging can defer system impacts for a significant period of time, however care must be taken to ensure that the control strategy does not create secondary peaks.

Fortunately, upgrading distribution systems is an issue that the EDCs plan and manage on a continued basis. For instance, CL&P participated in EPRI's 2010 study that examined individual circuits under various charging scenarios. Results showed no significant impact on a large scale to the local network. However, under certain circumstances some impacts could be experienced at a localized level. It is expected that CL&P's on-going distribution management system will adequately address PEV load as part of normal operations.

EDCs' Role in Managing the System Impacts

It is important for Connecticut to implement a proactive approach to monitor where the PEVs are appearing, and to address near-term localized impacts through appropriate system upgrades. The EDCs should also evaluate technologies and programs for managing long-term charging loads. Offering time-based rates that would incentivize off-peak charging is one such solution with a possible limitation that with low electricity prices relative to gasoline prices, PEV owners may still choose to charge at peak rates. These issues should be analyzed before PEV penetration numbers reach critical levels. The EDCs should deploy PEV pilot programs to better understand customer's charging profiles and whether the customers change their charging patterns in response to time-based rates. If they do not, the EDCs should explore other potential solutions

[20] *Ibid.*

such as delayed charging or managed charging. The key is to deploy these pilots and demonstrations sooner than later and collect data *now* to prepare better for the future.

Vehicle-to-Grid

Vehicle-to-Grid (V2G) refers to depleting the PEV batteries to provide power to the electric-grid when it is desirable to do so for the system. Vehicle batteries can ideally provide bulk energy storage, ancillary services, and regulation services. However, V2G is not a mature capability yet, as there are some issues that need to be resolved: (i) V2G would curtail the useful life of the batteries, so only high value uses are attractive; (ii) current battery warranties only apply to one way charging; (iii) V2G technology needs to be consistent with existing system rules; (iv) communication capabilities for sending the signal and validating the response must be developed; and (v) providing ancillary services would require introducing net metering rates at the retail level and standards for V2G service quality.

Barriers for Increased PEV Penetration

PEV penetration is expected to increase substantially over the next ten years; however there are some barriers that can slow the pace of PEV adoption, if not addressed on time.

Initial cost of the vehicle: PEVs are still relatively more expensive compared to conventional gasoline-fueled cars. Even after applying annual fuel cost savings, the all-in cost of owning a PEV exceeds that of a conventional gasoline-fueled car under current market conditions (see Figure 7). To the extent that the purchase decisions are mostly governed by the relative economics of owning a PEV, the penetration levels are not likely to ramp up quickly in the near term. However, as mentioned previously, there are other factors such as performance, consumer acceptance, and concerns on energy security and climate change that affect individual preferences. Depending on how each of these factors may play evolving roles in consumer decisions, projections for future penetration levels will vary widely.

Unfamiliarity and range anxiety: One of the biggest barriers to the adoption of all electric battery cars is fear that the battery will run out of power before reaching a destination with a charging facility ("range anxiety"). However, it must be understood that at this point in time, all-electric battery cars *are not* manufactured for long-distance driving. If these cars are used for commuting as they are intended at this point in time, the range anxiety may not emerge as a substantial barrier. The car will be parked most of the day and typically there will be sufficient amount of time to recharge. The range anxiety is not applicable to the PHEVs as these vehicles also have an internal combustion engine that can take over when the battery charge is depleted. Marketing campaigns will help inform consumers which different types of PEVs suit their driving needs, *i.e.*, long-distance driving vs. commuting.

Availability of charging infrastructure: One of the reasons for range anxiety is the limited availability of the charging infrastructure. It is reasonable to expect that the private sector will eventually be responsible for the majority of the infrastructure investment, but at the beginning the state might consider working with or providing incentives to the private sector to develop the required infrastructure. Also, there might be some near-term challenges in installing home charging devices due to permits, inspections, customer and contractor schedules, and PEV

metering installations. If not properly addressed, these transition challenges might slow the adoption of PEVs.

EDC's Role in Addressing the Barriers

Increase customer outreach and education. EDCs can develop customer outreach and education campaigns that inform customers about the pros and cons of owning PEVs. EDCs can establish customer service hot-lines and/or develop web-content to offer reliable information to their customers for their PEV related questions.

Offer time-based rates for lower monthly bills. EDCs could offer time-based rates to their PEV customers to encourage off-peak charging. To the extent that the customers can shift their charging load to the off-peak periods, they will pay lower rates compared to charging during peak periods. EDCs could market these rates aggressively and educate their customers on how to manage their PEV charging load.

Deploy safe and reliable PEV electricity metering. When PEV customers are on time-based rates, this requires installation of PEV electricity meters to be able to meter the PEV load separately from the entire house load. Without these meters, it is not possible to measure the hourly electricity usage of the PEVs and price this usage according to the time-based tariff. EDCs could also streamline the process for installing PEV electricity meters to minimize the customer discomfort and push-back.

Offer low-interest financing options for PEV home charging installations. As part of DSM programs or other utility programs, EDCs could offer low interest financing to their customers to make the necessary infrastructure updates in their homes and accommodate in-home charging devices.

Conduct system impacts studies and understand system readiness for PEVs. EDCs could implement a proactive approach to monitor where the PEVs are appearing, and address near-term localized impacts through system upgrades. It is important to address these problems before they become wide-spread and lead to service disruptions which could hurt customer trust as well as hinder PEV adoption.

Finally, a frequently asked question is whether the EDCs should be in the charging infrastructure business. EDCs could initially take part in the infrastructure investments. It is expected that the private sector will catch up fairly soon and develop the required infrastructure.

State's Role in Addressing the Barriers

Increase customer outreach and education. For seamless integration of the PEVs, customers will need support from both private sector and the state to become plug-in ready. The State could consider rolling out public service announcements and energy bill mail inserts educating customers on different PEV attributes such as its environmental benefits and the importance of off-peak charging. DEEP will consider recommending legislative action which includes working with the private sector to develop charging infrastructure. In addition DEEP will consider the following policy options:

Work with utilities and the private sector to develop the charging infrastructure. In order to help enable a critical scope of charging infrastructure, the state should consider working with the private sector to develop infrastructure. It is expected that private sector charging (retail, workspace, parking garages, *etc.*) will take off over time with proper incentives from the State, and oversight and consumer protection laws in place. For instance, the State Department of Transportation could consider when evaluating any new contracts at its train stations, parking lots, and service plazas whether charging stations can be included in the proposals.[21] The State could offer some targeted incentives (such as R&D tax credits) to support the deployment of charging infrastructure.

Introduce and/or renew incentives for PEV purchases. Customers who consider making a new vehicle purchase may respond favorably to an incentive from the state, such as a tax credit. These monetary incentives can improve the relative economics of PEVs and encourage more customers to purchase PEVs.

Introduce non-monetary incentives to promote PEV adoption. The State could also consider introducing some non-monetary incentives to promote PEV adoption. For instance, PEV owners may be offered favorable parking opportunities or access to high-occupancy vehicle (HOV) highway lanes.

Adopt PEVs within the State and universities' fleets and install supporting infrastructure. The State could lead by example and convert the bulk of its fleet into PEVs.

Develop and enforce building codes to make buildings PEV charge installation ready. Installation of the in-home PEV charging stations can be cumbersome due to permitting and inspection requirements. The State could consider developing and enforcing building codes to make new buildings PEV charge installation ready and streamline the installation process for the existing buildings.

Develop training programs for workers who will support PEV development. The State could consider providing training opportunities for workers who will play a fundamental role in the development of a PEV future. The State could particularly target technical high schools and community colleges to train technical staff for a seamless integration of the PEVs.

There are also a few issues the State could explore further. For instance, the State supports fast charging, but widespread fast charging can have very severe implications for generation and especially distribution systems. A fast charging tariff should be designed and should properly reflect all the costs it imposes on the system. The State could also consider exploring the issue of who would pay for the PEV electricity meters that are installed to customer premises to track the PEV charging load for time-based pricing purposes.

[21] State of Connecticut, "Electric Vehicle Infrastructure Council Final Report," September 2010.

ENERGY STORAGE

The future of renewables is in many ways dependent on the ability of scientists and researchers to develop a truly advanced electrical storage device or devices which will ensure that now intermittent sources of renewable energy can serve in a reliable, base-load generation capacity. This purpose can potentially be served well by energy storage due to its fast response time and its inherent ability to capitalize on volatile market prices. Connecticut is well positioned to take a leadership role in this effort, given its outstanding network of academic institutions and laboratories. In many ways, emerging storage technologies are the domain of the federal government given the massive amount of funding support required to drive these programs, but the state can be additive in the process by organizing and encouraging federal grant proposals, supporting pilot demonstrations, and bringing attention to the issue on a state communications level.

There is a very wide range of available energy storage technologies. These technologies vary across many dimensions, such as technological maturity, cost, power (MW), capacity (MWh), discharge time, efficiency, physical footprint, cycling capability, and useful lifetime. Some technologies, such as batteries and thermal energy storage applications, can be used "behind the meter" as a form of backup generation to improve reliability or power quality for individual customers. Other forms of energy storage, such as pumped hydro or compressed air energy storage (CAES), are purely grid-scale resources. A summary of the types of available energy storage technologies, and the advantages and disadvantages of each, is provided in Figure 9.

Figure 9: Summary of Energy Storage Technologies

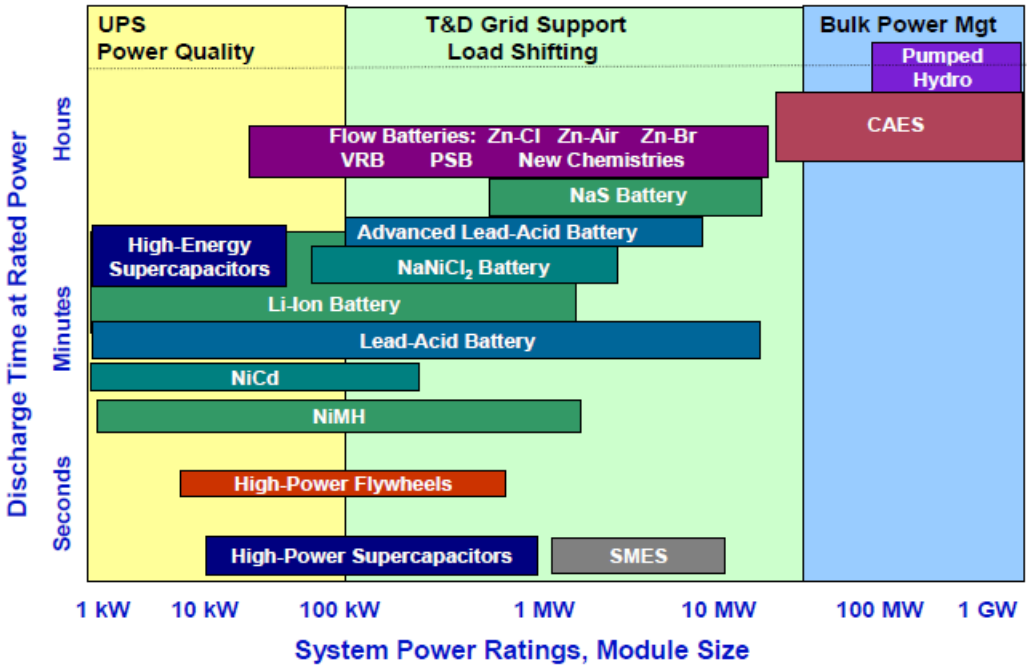
Technology	Advantages	Disadvantages	Major Applications
Pumped Hydro	Huge energy and power capacity	Geographically limited Expensive to build Long construction time Large scale only	Energy arbitrage Frequency regulation Ancillary services
Compressed air energy and storage (CAES)	Huge energy and power capacity	Geographically limited Requires fuel input Long construction time Large scale only	Energy arbitrage Frequency regulation Ancillary services
Regenerative Fuel Cells (ZBB, VRB)	Independent energy and power sizing Scalable for large applications High energy and power density	Relatively early stage technology Relatively expensive	Load leveling Backup power
Lead-acid batteries	Mature technology Inexpensive High availability	Low specific energy and power Short lifetime High maintenance requirements Environmental hazards Reduced capacity at low temperatures	Automobiles UPS/Telecom/Substation reserve power
Advanced batteries (Li-ion, NiMH, NaS)	High power and energy density Longer lifetime Higher efficiency Lower maintenance	Too expensive for large-scale applications	Automobile Consumer electronics Power quality and backup power
Supercapacitor	High power density Longer lifetime Quick charge	Low energy density Expensive Sloped voltage curve requires power electronics	Power quality Emergency bridging power Fluctuation smoothing
Superconducting magnetic energy storage (SMES)	High power	Low energy density Large parasitic losses Expensive	Power quality Emergency bridging power
Flywheels	High power density Longer lifetime Quick charge Independent power and energy sizing	Low energy density Large standby losses Potentially dangerous failure modes	Frequency regulation Power quality Emergency bridging power Fluctuation smoothing

Sources:
[1] Market Analysis of Emerging Energy Storage Systems, NETL (2008)
[2] U.S. Dept. of Energy, Energy Efficiency and Renewable Energy (EERE) website

Energy storage has many potential applications. It can act as generation, providing capacity, energy shifting, and ancillary services to integrate renewables and reduce system costs. It can also support the transmission system, by avoiding congestion fees through local dispatch or deferring new infrastructure investments. On the distribution system, it can improve power quality, mitigate outages, or delay substation capacity upgrades. And at the end-user level, energy storage can provide a means for reducing bills on time-varying retail rates, or provide uninterruptible power supply (UPS). The degree to which energy storage can be applied in these ways is largely a function of feasible dispatch time and the size (and footprint) of the technology. Figure 10 summarizes the functionality of various energy storage options across this spectrum.[22]

[22] Reproduced from EPRI, "Electricity Energy Storage Technology Options," December 2010.

Figure 10: Energy Storage Technology Functionality



Energy Storage in the Unites States

In the United States, roughly 2.5% of electricity is supplied through energy storage. Nearly all of this — roughly 20 GW — is from pumped hydro.[23] CAES provides an additional 110 MW of capacity through a facility in Alabama. Larger CAES projects in the U.S. are in development or proposed in Iowa, California, and New York.

Otherwise, energy storage is happening on a much smaller scale. Some critical industries such as airports and hospitals use energy storage as a backup source of extremely reliable electricity supply. Electric utilities have sponsored projects to promote adoption of thermal energy storage among larger commercial and industrial customers for many years (Southern California Edison's Permanent Load Shifting program is one example).[24] Additionally, demonstration projects and R&D programs for a range of storage technologies are underway around the country. Many of these are being supported through $250 million in Department of Energy (DOE) stimulus funds. EPRI expects that the findings of these projects will significantly advance the state of the technology and could change the energy storage landscape by 2015.[25]

Over the next decade, market penetration of energy storage technology will be determined by a number of factors, the most significant of which is cost competitiveness. Simply put, most of today's energy storage technologies are too expensive to economically compete with other resource options outside of niche applications. Driving down the cost of the technology as well as driving up the capacity of devices will be critical. "Moore's Law" in microprocessor

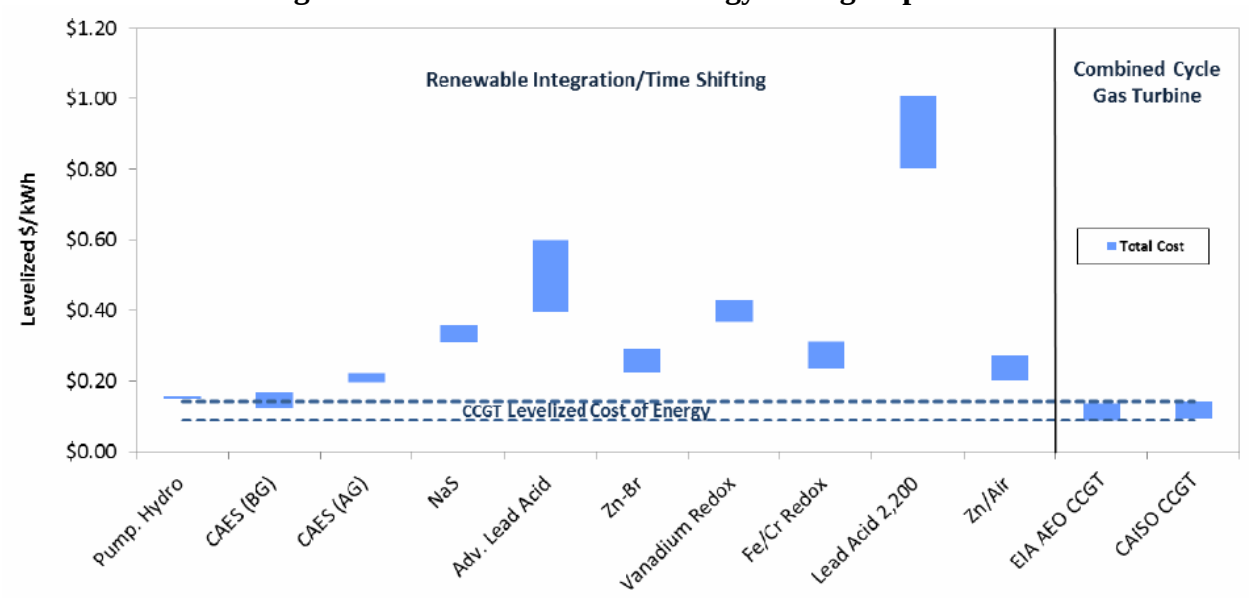
[23] EPRI, "Estimating the Costs and Benefits of the Smart Grid," Technical Report, March 2011.

[24] http://www.sce.com/pls/permanent-load-shifting.htm

[25] EPRI, "Electricity Energy Storage Technology Options," December 2010.

technology has proven that there is the capacity for rapid scientific advancements in cost reduction and performance improvement over very short periods of time. A similar drive is required to adequately meet the current challenges that renewable technologies face in the marketplace. Figure 11 summarizes a recent EPRI analysis of the levelized cost of energy storage options relative to that of a gas-fired combined cycle (CC) unit.[26] It should be noted that the costs of energy storage technologies are difficult to summarize on a consistent basis, because they depend on the specific application for which the technology is being developed. In this instance, the figure assesses the cost of options capable of facilitating the integration of intermittent renewables.

Figure 11: Levelized Cost of Energy Storage Options



EPRI finds that if energy storage systems could be installed at a cost of $700 to $750/kWh and that the full stream of possible benefits could be monetized (requiring fast response time), an additional 14 GW of energy storage could be cost-effectively added to the U.S. power grid. At a price of $1,400/kWh, which is in the range of the cost of many of the currently emerging technologies, the niche market for energy storage is roughly 5 GW. Many in the industry consider $500/kWh to be the critical tipping point at which the cost of energy storage would become competitive with other resource options and achieve widespread deployment. Of course, this analysis is highly dependent on assumptions about market prices, the penetration of renewable resources, and other industry dynamics. To the extent that markets progress toward conditions that are more economically favorable for energy storage, the estimate would differ.

Energy Storage in Connecticut

Due primarily to high costs as well as other challenges that are discussed later in this section; it seems unlikely that energy storage will achieve significant market penetration in Connecticut within the coming decade. In fact, no significant energy storage projects were identified in

[26] *Ibid.*

Connecticut other than the 30 MW Rocky River pumped hydro facility and ongoing research on emerging technologies at local universities. Instead, Connecticut can focus on the development and application of battery energy storage technologies and other more recently developed storage technologies through our universities, community-colleges and other state entities focused on advancing emerging technologies. If costs come down significantly and certain energy storage technologies become more competitive with conventional sources of supply, the following factors could potentially make Connecticut a relatively attractive market for energy storage:

- *Strong RPS:* The State's RPS will introduce a significant amount of new intermittent resources by 2020, which will increase the integration value of more flexible resources like energy storage. A key question is whether this increased penetration of renewables will be enough to significantly affect the value of these flexible resources. Another key question is whether the location of the renewable resources (primarily out of state) will influence the optimal location of any energy storage.
- *Effective demand-side participation:* The ability of demand-side resources to participate in New England's wholesale markets (particularly the capacity market) suggests that there could be fewer barriers to monetizing the full value of energy storage in Connecticut than some other parts of the U.S.
- *Progressive state environmental policy:* The State's focus on reducing harmful emissions suggests that policymakers may be more likely in the future to adopt policies to promote the adoption of energy storage, to the extent that it is demonstrated to have environmental benefits.

Other factors could potentially lessen Connecticut's attractiveness as a market for new energy storage technologies:

- *An expectation of low volatility in energy prices:* Energy prices in Connecticut have not exhibited a high level of volatility, and a recent decision to increase the state's planning reserve margin by 1,000 MW could further dampen volatility. Low gas prices further contribute to this effect.
- *Low load growth:* Low load growth will reduce the region's demand for wind and has caused several New England states to reexamine future wind buildout scenarios.

DEEP will discuss further with its sister agencies including DECD and the universities whether a more detailed study to assess the relative attractiveness of Connecticut as a market for emerging technologies including energy storage would help to refine these high level observations and provide greater direction for policy initiatives.

Barriers to Deployment

Deployment of most forms of energy storage is still largely limited by its cost-competitiveness, although other barriers may further inhibit its acceptance. The following are some of the most commonly cited barriers to energy storage deployment:

- *Cost competitiveness:* In most cases, the benefits of energy storage still are not proven to outweigh the high technology and manufacturing costs.[27] For example, a recent study by Southern California Edison found that the benefit-cost ratio of a wide range of energy storage technologies and applications ranged between 0.01 and 0.4 (but recognized that these estimates would change as future costs and system conditions evolved).
- *Lack of awareness of energy storage benefits*. Since most energy storage technologies have not been deployed at a large scale, many policy-makers are not familiar with their potential benefits. This could lead to a lower prioritization of energy storage among state policy objectives than other emerging resource options.[28]
- *Regulatory and utility business models that do not recognize full value:* The full benefits of energy storage are sometimes not reflected in current methodologies for evaluating new resources as part of the regulated energy procurement process. For example, this could include the value of energy storage as an alternative to T&D investment, or the value of its highly flexible operational characteristics. Further, because energy storage can offer benefits at the generation, transmission, and distribution levels, determining cost allocation across these elements of the electric system presents a challenge to regulators.[29]
- *Monetizing benefits:* The wide-ranging benefits of energy storage that accrue to multiple stakeholders can make the logistics of monetizing the benefits a challenge. This can lead to complicated rules of ownership.
- *System integration challenges:* Energy storage could enable bi-directional energy flows, creating problems for existing tariff, billing, and metering approaches.

Addressing the Barriers

A number of policy options could help to overcome barriers to energy storage deployment in the future. It is not necessarily recommended that the state pursue all of these activities; whether these options are pursued will depend on the extent to which the state wishes to make energy storage a priority and subsidize its development in the short-run, in order to promote its market competitiveness in the longer term. Some options may be better pursued at the federal level.

State program to organize efforts to secure federal and private funds for R&D. DEEP will commence dialogue with DECD and quasi-state agencies to consider creating a program in state

[27] Less costly forms of energy storage, such as pumped hydro, face permitting or siting challenges, as described in this section.

[28] Ethan Elkind, "The Power of Energy Storage," whitepaper sponsored by Bank of America and supported by UCLA School of Law and UC Berkeley School of Law, July 2010.

[29] California Public Utilities Commission, "Electric Energy Storage: An Assessment of Potential Barriers and Opportunities," Policy and Planning Division Whitepaper, July 9, 2010.

government that serves as a resource to entities that seek to do R&D work related to storage technologies within Connecticut. DEEP believes that there are state initiatives through the DECD and CEFIA that may already be encouraging the entry of such businesses.

Modify regulatory framework to better recognize full value of storage. To address energy storage challenges related to current regulatory frameworks and utility business models, a new cost-effectiveness methodology for evaluating energy storage options could be developed to better reflect the full value of the technology. Additionally, the cost of energy storage could be allowed to be recovered in the ratebase. It could also help to clearly define the ownership structures through which storage can be used for both generation and grid uses (in some jurisdictions, a grid asset may not participate in wholesale energy markets). A first step in this activity would be to review similar efforts that are underway in other states (such as California).

Policy-maker education. To address a lack of familiarity with the benefits of energy storage among policy-makers, the State could create stakeholder groups, host workshops, compile publicly-available information on energy storage performance, fund demonstration projects, or initiate the development of a roadmap for achieving the State's vision for energy storage.

Encourage time-varying rates: One way to encourage adoption of energy storage at the retail level is to offer time-varying retail rates with strong price signals and designs that align well with the operating characteristics of behind-the-meter storage options.

Consider energy storage during transmission planning: To ensure that the transmission-related benefits of energy storage are recognized, it could be considered as an option in future transmission planning activities.

Tax credits or other financial incentives: An investment tax credit or other financial incentive could help to spur the financing of otherwise risky energy storage projects and promote cost or performance improvements.

Streamline siting or interconnection rules: To reduce delays or costs that may be associated with applying to develop and connect an energy storage project to the grid, the application requirements could be examined for opportunities to create a more streamlined process.

GEOTHERMAL ENERGY

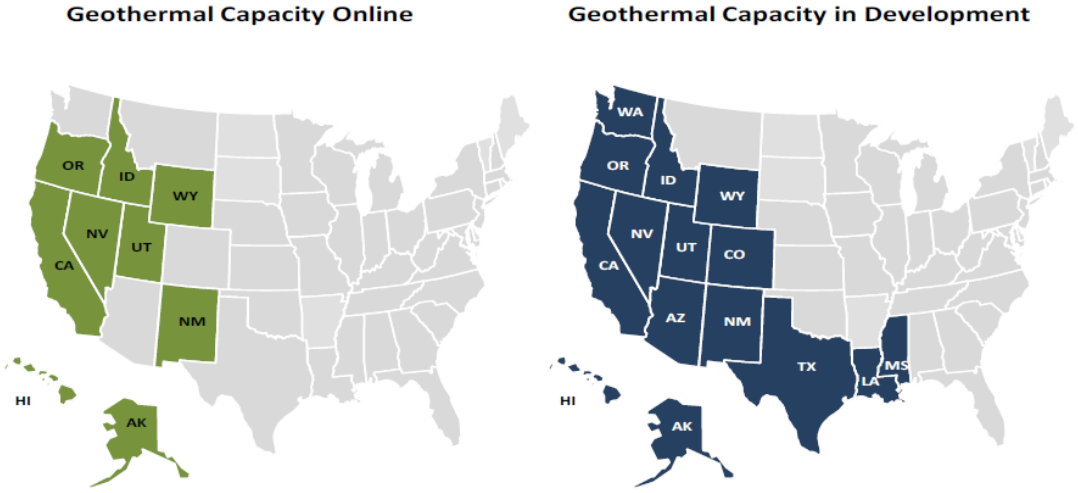
Geothermal energy represents the use of the earth's natural heat to create steam to turn turbines and generate electricity. The quality of a geothermal resource depends on a number of factors, including the depth at which sufficiently high temperatures are reached, the reservoir rock's permeability and porosity, and the amount of fluid saturation in the reservoir (for producing steam). Benefits of geothermal energy are that it is clean, reliable, and available as a domestic resource.[30]

[30] U.S. DOE Website. http://www1.eere.energy.gov/geothermal/geothermal_basics.html

Geothermal Energy in the United States

There are currently roughly 3,100 MW of geothermal capacity in the US, spanning seven western states, Hawaii, and Alaska. Of this capacity, more than 80% is located in California.[31] Since 2005, geothermal capacity has grown at a slow but steady pace, with roughly 400 MW of capacity added in that timeframe.[32] In addition, the Geothermal Energy Association estimates that 5,000 to 6,000 MW of geothermal projects are in development, although much of this capacity is still in the early phases and may not fully materialize. Roughly 700 to 800 MW are in the advanced drilling and construction phase and are expected to be completed within the next three to four years. The states with geothermal capacity online or in development are summarized in Figure 12.[33]

Figure 12: States with Geothermal Capacity Online or in Development



Source: GEA

Geothermal developments have benefitted from federal support. With certain restrictions, geothermal projects are eligible for the production tax credit. Additionally, the 2009 American Recovery and Reinvestment Act (ARRA) made cash grants available for eligible projects. More than $260 million in federal grants have been provided to utility-scale geothermal projects since 2009.[34] Federal funding is also being used to promote research and development of new

[31] Geothermal Energy Association Website: http://www.geo-energy.org/plants.aspx

[32] Geothermal Energy Association, "Annual U.S. Geothermal Power Production and Development Report," April 2011.

[33] Reproduced from the Geothermal Energy Association's *Annual U.S. Geothermal Power Production and Development Report*.

[34] *Ibid*.

geothermal technologies. More than $360 million has been awarded for this purpose.[35] Research and development projects have focused on:

- Innovative exploration and drilling
- Coproduced, geo-pressured, and low temperature geothermal demonstrations
- Enhanced geothermal system demonstrations
- Enhanced system components research and development
- Geothermal data collection
- Ground source heat pump demonstrations

Geothermal Energy R&D in Connecticut

There currently are not any geothermal developments in Connecticut (or anywhere else in New England). However, a $400,000 DOE grant is funding a three-year project to identify Connecticut's and Massachusetts' potential for geothermal power. Additionally, of the $360 million in federal funding that was awarded for research and development in 2009, $4.4 million was allocated to organizations in Connecticut. Figure 13 provides a brief description of each R&D project, all of which were scheduled to complete by late 2011 or early 2012.[36]

Figure 13: Federal Stimulus Funding for Geothermal R&D in Connecticut

Award Winner	Award Amount	Description
United Technologies Research Center	$1.8 million	Identify and test more efficient heat transfer fluids for binary power plants.
United Technologies Research Center	$1.2 million	Optimization of hybrid-water/air-cooled condenser to reduce water consumption and to improve cooling of binary power plants in an enhanced turbine geothermal binary system.
Gas Equipment Engineering Corporation	$1.2 million	Create an across-the-board analysis of the costs of building and operating a 50 MW EGS power plant. Model will be used to predict future development costs, as well as guide research and financial incentive development.
University of Hartford	$0.1 million	Develop an integrated system simulation and design model for hybrid GHP systems designed to effectively balance ground thermal loads.

Barriers and Policy Options

Despite these research and development activities, it seems very unlikely that geothermal energy will have an impact on Connecticut's resource planning in the coming decade. This is mostly

[35] An additional $38 million was awarded for new R&D projects in September 2011. See the DOE press release: http://apps1.eere.energy.gov/news/news_detail.cfm/news_id=17723

[36] http://energy.gov/sites/prod/files/edg/news/documents/338M_Geothermal_Project_Descriptions.pdf

due to the low resource potential in New England, which accounts for only 1% of the total U.S. potential.[37] Even with the advent of new breakthrough technologies, other parts of the country — particularly the west — are more attractive candidates for geothermal development due to natural characteristics of much higher temperatures at shallower depths below the earth's surface. An effort to promote the development of geothermal energy in Connecticut would need to focus on developing innovative drilling technologies, power conversion technologies, and reservoir technologies that are available at much lower costs.

ADVANCED WASTE-TO-ENERGY (AWE)

Waste-to-energy includes technologies that use municipal solid waste as a fuel to generate electricity. This approach, while not the most efficient way to generate electricity, provides its primary value in waste disposal. For example, in Connecticut, more than 60% of the state's trash (which would otherwise be destined for a landfill) is consumed through waste-to-energy processes.[38]

Waste-to-energy is widely utilized around the globe. In most cases, the process relies on the incineration of waste to generate heat to power steam generators. This approach has been in practice for many years. However, a challenge with direct combustion is that it can release harmful emissions into the air. Addressing this problem requires investment in costly emissions control technologies.

Several advanced forms of waste-to-energy are emerging which do not rely on direct combustion. These advanced waste-to-energy (AWE) options can be categorized as thermal options (which require high temperatures to process the waste) or non-thermal options (which rely on biological processes to break down the waste and produce combustible gases). It is these emerging forms of waste-to-energy that are the focus of this section.

AWE Deployment in the United States

AWE applications for the purposes of generating electricity are limited in the U.S. to a few small facilities and research projects.

Examples of emerging thermal options are:

- **Gasification:** Waste is converted to a combustible gas by exposing it to a high degree of heat and a limited amount of oxygen, but without combustion. While few waste gasification facilities are in operation, they have been proposed in Massachusetts, Georgia, and Wisconsin. In California, the city of Los Angeles uses a gasification process on dried sewage sludge to drive a 10 MW steam generator.[39]

[37] MIT, "The Future of Geothermal Energy," 2006.

[38] Connecticut Legislative Program Review & Investigations Committee, "Municipal Solid Waste Services in Connecticut," January 2010. Technically speaking, landfill gas use for power generation is also a waste-to-energy technology, but is not considered emerging.

[39] http://www.energy.ca.gov/biomass/msw.html

- **Thermal depolymerization:** Superheated water is used to convert waste into light crude oil. Plants in Pennsylvania and Missouri use this process specifically in waste management.
- **Pyrolisis:** A high degree of heat (in the absence of oxygen) is used to convert waste to a combustible substance. This process is used, for example, to create charcoal.
- **Plasma Arc Gasification:** Electricity and high temperatures are relied on to convert waste to energy. No commercial facilities have yet been developed specifically for the purposes of processing municipal solid waste, although plans have been announced in the U.S. in states such as Florida and California.

Emerging non-thermal options include:

- **Anaerobic digestion:** Microorganisms break down biodegradable material in the absence of oxygen to produce combustible gas. Small facilities have been developed, for example, by farms to treat agricultural waste and generate electricity (up to 100 kW) as a byproduct.[40]
- **Mechanical biological treatment:** Includes a process that sorts and separates waste into those materials that can be treated through a biological approach like anaerobic digestion, from those that cannot.

AWE Deployment in Connecticut

Connecticut has significant waste-to-energy resources at six facilities with a capacity of 185 MW. These facilities process more than 60% of the state's municipal solid waste. In fact, Connecticut processes a higher share of its municipal solid waste through these processes than any other state in the country (Massachusetts is second with 37%). A recent waste management planning study concluded that the state does not require any new waste-to-energy facilities through 2024.

There is also some interest in advanced forms of waste-to-energy in the state. For example, a new gasification plant in Stamford is currently in development and will eventually provide 15 MW of electricity generation capacity. The project received a $3 million federal grant and is currently in the design stage. The process relies on pyrolysis to create a charcoal-like substance, and then converts that matter into gas at high temperatures. The total cost of the plant will be $60 million.[41]

Additionally, CEFIA is establishing a pilot program to test the use of anaerobic digestion on organic waste to produce electricity and heat. As specified by state legislation (P.A. 11-80, Section 103(b)), the pilot program will last three years and will support five pilots through loans, grants, or power purchase agreements. Each project will be a maximum of 1.5 MW, at a price

[40] See, for example: http://www.energy.ca.gov/biomass/anaerobic.html.

[41] http://www.stamfordbiogas.com/WEF.pdf.

not to exceed $450/kW. Anaerobic digestion is being further promoted through another piece of state legislation (P.A. 11-217) that requires certain facilities to separate and recycle organic waste.

Given that AWE is still in the early stages of research and development, with fairly limited funding, there is little reason to believe that it will become a very significant resource over the coming decade. A high rate of traditional technology utilization with substantial remaining economic life also impedes the prospects for AWE deployment.

Barriers to Deployment

The most significant barrier to greater AWE adoption is that experience with the technology is currently very limited, with few large-scale commercial applications. Due to the newness of the technology, its effective operation requires a high level of technical expertise that is not commonly found in the waste management or energy industries. Some processes suffer from low levels of efficiency in converting waste to energy. Additionally, emissions from waste-to-energy plants can be problematic, although this tends to be a bigger concern for direct combustion than it is for the newly emerging forms of waste-to-energy.

Addressing the Barriers

Given the nascent state of AWE technology, the most effective state-level activities for promoting its adoption would be focused on facilitating technological development. This could be pursued by funding a demonstration project, supporting research through a local university, or even offering a monetary prize to the organization that could develop an AWE technology that meets a pre-defined set of cost and performance characteristics. Activities to educate the public about the potential benefits of AWE could also be useful for gauging public support for developing the technology. DEEP proposes to look more closely at the potential for the enhanced use of biofuels including waste to energy through its 2012 Comprehensive Energy Strategy and include any findings in the next iteration of the IRP.

APPENDIX I

ECONOMIC IMPACT ANALYSIS FOR RENEWABLE ENERGY, ENERGY EFFICIENCY AND NEW GAS GENERATING PLANT

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INTRODUCTION

This appendix describes the methodology and results of the employment and macroeconomic analyses performed to support the 2012 Connecticut IRP. As part of the IRP, DEEP requested the assistance of Connecticut's Department of Economic and Community Development (DECD) in simulating Connecticut's economy under various scenarios to estimate the potential economic and employment impacts of certain investment activities. The Brattle Group, in turn, used the results of DECD's simulation to form the employment and macroeconomic metrics in the IRP. Specifically, these metrics include: a) the number of full-time-equivalent jobs, b) the state's gross domestic products (GDP), c) the state's economic output, and d) the state's new revenues.

The relevant investment decisions examined in the IRP scenarios primarily involve three types of activities. They include investments in in-state renewable energy resources, energy efficiency programs, and a new power plant. As these investments ultimately affect electric customers' costs, they also will indirectly influence the state's economy. Separately, we simulated the potential effects of the state issuing a new bond to fund some of the investment activities. Unless otherwise stated, the employment and economic impacts, estimated in the IRP and in this appendix, include direct, indirect, and induced effects.

All simulations were performed using an input-output model, developed and maintained for the Connecticut Center for Economic Analysis by Regional Economic Models, Inc. (REMI). The employment and economic impact metrics reported in the IRP focuses on the *relative* magnitude of jobs and macroeconomic activities in each scenario compared to the Base Case. DECD used the REMI simulations to estimate the economic impact of *changes* in spending and The Brattle Group applied the relative changes to each scenario.[1] Each investment activity is simulated independently and therefore the analysis does not account for any interactive or offsetting effects.

Below, we describe the activities considered in simulating the employment and macroeconomic effects.

ECONOMIC IMPACT ASSOCIATED WITH INVESTMENTS IN RENEWABLE ENERGY

For every Resource Scenario explored in the IRP, the Class I Alternative Compliance Payments (ACPs) are collected whenever paying the ACP is cheaper than purchasing Renewable Energy Credits (RECs) to comply with the Class I requirements. We assume that ACP dollars collected by the state will be used to pay for new solar PV/small wind projects and fuel cell technologies installed in Connecticut. The level of ACPs collected and the various levels of renewable resources added to the New England grid can affect the costs of

[1] The employment and economic impact analyses are only performed for the Base Case and various Resource Scenarios. They are not conducted for the various Alternative Futures.

power to electric customers. In this section, we describe the estimated employment and macroeconomic impacts associated with investing those ACP dollars and later we show the estimated impacts associated with the increases and decreases of customers' spending on electricity

To estimate the potential employment and macroeconomic impact of spending the ACP dollars on in-state renewable energy development, we apply four sets of independent 'shocks' to two industry sectors. The shocks are simulated in the form of increases and decreases in spending by homeowners and businesses on solar PV, small wind, and fuel cell projects. For purposes of this analysis, we assume very minimal public sector involvement when, in reality, there may be some associated economic activity and people employed in administering the ACP account and distributing the payments to various programs. To simulate home and business owners' spending on solar and small wind installations, we assume that specialized trade contractors perform the work and that a significant portion of the spending represents equipment not manufactured in Connecticut. For instance, a significant portion of spending on solar and small wind installation leaves the state with only a small number of construction jobs to be added each year.

Investments in fuel cell projects can stimulate the growth of the relevant industries in Connecticut. The fuel cell industry consists of several sectors that contribute materials or components to fuel cell manufacturers in Connecticut.[2] For purposes of this analysis, we assume increases in spending for fuel cells injects spending into the 'All Other Miscellaneous Electrical & Component Mfg.' (NAICS 335999) sector in which Connecticut's fuel cell manufacturing firms are situated. We assume that the spending shocks last for 20 years from 2012 through 2031.

Figure 1 summarizes a sample of results from the REMI simulations where the spending shocks (in column [1]) are independently applied. The simulation results shown are the annual average changes from the Base Case over the 20-year period. As an example, the first row of Figure 1 shows the estimated impact of a $10 million increase in spending by homeowners on residential solar and small wind installations across the state. If the same spending is applied every year, approximate an average of 70 full-time-equivalent (FTE) jobs[3] would be added each year. Similarly, if $10 million were spent on fuel cell projects, our simulation shows that approximately 54 jobs would be associated with that spending.

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[2] These include 'Surface-Coated Paperboard Mfg.' (NAICS 322226) for cell stacks, 'Printed Circuits and Electronics Assemblies' (NAICS 334418) for inverters and switchgear, 'All Other Miscellaneous Electrical & Component Mfg.' (NAICS 335999) representing fuel cell manufacturers, 'Computer & Computer Peripheral Equipment & Software Merchant Wholesalers' (NAICS 423430) for systems control and monitoring, and 'Hydrogen Mfg.' (NAICS 325120) for mobile fuel cells. See "The Economic Impact of the Renewable Energy/Energy Efficiency Industry on the Connecticut Economy," Stanley McMillen, July 2009, for a proposed taxonomy of renewable energy and energy efficiency industries. Available on request.

[3] A full-time-equivalents ("FTE") employment year is approximately 2,080 hour units of employment. For example, reporting 100 jobs could mean 200 workers supported for 6 months or 100 workers supported for one year.

Figure 1
Economic Impact Metrics for Residential Structures and Fuel Cell Manufacturing

	Changes Simulated	TOTAL EFFECTS: Average Annual Changes from Baseline Forecast				
	Annual Change in Industry Sales for 20 Years *($/yr)* [1]	Change in All Jobs *(FTEs)* [2]	Change in Construction Jobs *(FTEs)* [3]	Change in State GDP *($/yr)* [4]	Change in Industry Sales Output *($/yr)* [5]	Change in Net State Revenue *($/yr)* [6]
Residential Structures (Solar PV & Small Wind)	Plus $10 million	69.8	47.3	$9,166,292	$13,864,587	$420,000
	Minus $10 million	-69.6	-47.3	-$9,133,864	-$13,837,655	-$439,000
Fuel Cell Manufacturing	Plus $10 million	54.2		$6,294,440	$12,863,149	$216,500
	Minus $10 million	-54.7		-$6,308,731	-$12,904,372	-$202,000

ECONOMIC IMPACT ASSOCIATED WITH ENERGY EFFICIENCY PROGRAMS

For scenarios where spending on energy efficiency (EE) programs vary, we applied four types of spending shocks to multiple industry sectors simulating the costs and benefits of various types of energy efficiency programs. Because different types of energy efficiency programs can affect the local economy differently, we simulated the EE program spending in the form of increases and decreases in spending on: (1) weatherization, (2) heating and cooling equipment upgrades, (3) lighting, and (4) other administrative, marketing and educational activities. Below we describe each of the four components of EE spending.

Weatherization

To estimate employment and macroeconomic effects, we assume that weatherization programs include insulating and sealing ductwork, insulating and sealing buildings and windows, and installing energy-efficient doors, windows, and siding.[4] Figure 2 below summarizes the allocation assumptions used for every $10 million in spending on weatherization activities. We allocate spending on weatherization programs across six industries based on their employment shares in the industry and by aggregating roofing contractors and drywall and insulation contractors in a sector called 'maintenance and repair of residential structures. Specifically, the percentages by business sectors show the relative proportion of the spending for weatherization programs. This allocation assumption is used as an input to the REMI simulations. For the purpose of the economic impact simulation, we treat the spending as an annual spending over 20 years.

[4] We do not include spending on efficient lighting or household appliances, modifying buildings for increased daylighting, or converting to energy-efficient heating and cooling systems. The former affects the wholesale and retail sectors primarily while the latter affects the HVAC sector (a subsector of Specialty Trade Contractors, NAICS 238).

Figure 2
Weatherization Spending Allocation

Industry	Spending Allocation	Share of Total
Maintenance & Repair of Residential Structures	± $6,349,003	63.5%
Glass Products Made From Purchased Glass (NAICS 327215)	± $2,291,933	22.9%
Urethane and Other Foam Product (except Polystyrene) Mfg. (NAICS 326150)	± $685,934	6.9%
Wholesale Trade	± $457,289	4.6%
Wood window & Door Mfg. (NAICS 321911)	± $107,920	1.1%
Mineral Wool Mfg. (NAICS 327993)	± $107,920	1.1%
	± $10,000,000	**100.0%**

Figure 3 shows sample results of simulating $100 million more and less spending on weatherization programs compared to the Base Case and these results incorporate direct, indirect, and induced effects. The direct effects represent the initial spending by home and business owners for construction services for the weatherization activities. The indirect effects represent the new business-to-business activities associated with the initial spending while the induced effects represent the spending of payrolls by workers involved in the industry affected in the first round of spending and the next round of indirect activities. The estimated change in GDP (in column [4]) represents the change in value added in the affected sectors while the change in output (in column [5]) represents the change in sales in the affected sectors that are associated with the initial spending by home and business owners. The estimated change in the net state revenue (in column [6]) is the difference between the changes in revenue from all sources and expenditure for all uses. In comparing the change in GDP (in column [4]) to the initial spending (in column [1]), it is worth noting that the average annual change in state GDP is less than the initial spending because there are leakages from the state in the form of equipment and subassemblies manufactured elsewhere.

Figure 3
Economic Impact Metrics for Weatherization

Changes Simulated Annual Change in Industry Sales for 20 Years *($/yr)* [1]	**TOTAL EFFECTS: Average Annual Changes from Baseline Forecast** Change in All Jobs *(FTEs)* [2]	Change in Construction Jobs *(FTEs)* [3]	Change in State GDP *($/yr)* [4]	Change in Industry Sales Output *($/yr)* [5]	Change in Net State Revenue *($/yr)* [6]
Plus $100 million	626.9	315.3	$81,361,080	$137,656,526	$4,148,500
Minus $100 million	-612.3	-305.9	-$79,447,245	-$134,773,681	-$4,143,000

New Heating and Cooling Equipment Programs

For program spending associated with upgrading heating and cooling equipment, we apply annual spending shocks to the residential and non-residential maintenance and repair sectors for 20 years, simulating home and business owners' spending for the installation of high-efficiency heating and cooling systems. Though most of the heating and cooling equipment is not manufactured in Connecticut, the system design, installation, maintenance, and repairs are expected to be sourced locally in the state. Figure 4 shows the results of simulating $100 million more or less spending on heating and cooling equipment upgrades, relative to Base Case, on residential and non-residential buildings.

Figure 4
Economic Impact Metrics for New Heating and Cooling Equipment

	Changes Simulated Annual Change in Industry Sales for 20 Years *($/yr)* [1]	**TOTAL EFFECTS: Average Annual Changes from Baseline Forecast** Change in All Jobs *(FTEs)* [2]	Change in Construction Jobs *(FTEs)* [3]	Change in State GDP *($/yr)* [4]	Change in Industry Sales Output *($/yr)* [5]	Change in Net State Revenue *($/yr)* [6]
Residential Structures	Plus $100 million	242.8	163.3	$31,650,338	$47,921,861	$1,465,230
(HVAC)	Minus $100 million	-237.7	-160.0	-$30,987,674	-$46,915,905	-$1,447,210
Non-Residential Structures	Plus $100 million	477.6	389.4	$28,394,576	$45,407,251	$2,491,520
(HVAC)	Minus $100 million	-471.7	-385.9	-$27,654,918	-$44,279,078	-$2,509,200

Lighting Programs

We represent new spending by home and business owners on high-efficiency lighting and appliances as new sales in the wholesale and retail sectors. In each sector, we apply the new spending for 20 years. The effect of this spending is not entirely felt in Connecticut because most goods purchased from wholesale and retail establishments are not manufactured in the state and must be transported from the point of manufacture to the wholesale or retail establishment. We assume that lighting programs for residential customers will yield purchases of lighting fixtures and light bulbs from retail stores while commercial and

industrial lighting programs will yield purchases from wholesale stores. The state benefits in the amount of the gross margins for retail (28%) and wholesale (20%)[5] that accounts for local wages, rent, and taxes. The economic model uses prices at the point of manufacture and therefore goods manufactured outside Connecticut and sold in the state contribute a small portion of their sale price to the state's economy. Figure 5 below shows the results of simulating $10 million more or less spending on residential and commercial/industrial lighting programs relative to the Base Case.

Figure 5
Economic Impact Metrics for Lighting Programs

	Changes Simulated	**TOTAL EFFECTS: Average Annual Changes from Baseline Forecast**				
	Annual Change in Industry Sales for 20 Years *($/yr)* [1]	Change in All Jobs *(FTEs)* [2]	Change in Construction Jobs *(FTEs)* [3]	Change in State GDP *($/yr)* [4]	Change in Industry Sales Output *($/yr)* [5]	Change in Net State Revenue *($/yr)* [6]
Wholesale Trade	Plus $10 million	8.9	0.4	$1,731,905	$2,495,901	$59,500
@ 20% Gross Margin	Minus $10 million	-8.9	-0.4	-$1,688,484	-$2,426,097	-$62,500
Retail Trade	Plus $10 million	27.1	1.0	$2,470,617	$3,545,157	$61,000
@ 28% Gross Margin	Minus $10 million	-27.9	-1.2	-$2,496,450	-$3,616,060	-$100,500

Other Administrative Activities Associated with EE Programs

Additional costs associated with administering and educating consumers about demand-side programs may include setting up new functions at the utilities and with outside contractors. Thus, we convert certain administrative costs to utility sector jobs using the utility industry average compensation ($149,081 in 2012)[6] to estimate the number of jobs associated with spending. We also estimate the indirect effects associated with those jobs. In addition, we simulated a portion of the administrative and educational spending as sales in the business services sector (NAICS 561, 'Administrative and Support Services) that receives contract work to implement EE and other demand-side management programs from the utilities. Figure 6 shows the impact associated with $10 million more or less spending in administrative activities compared to the Base Case.

[5] See http://www.census.gov/retail/ and http://www.census.gov/wholesale/.

[6] Compensation includes wages or salaries and fringe benefits. The industry average compensation comes from the REMI economic model of the state economy (see Appendix A).

Figure 6
Economic Impact Metrics for Other Administrative Activities

	Changes Simulated Annual Change in Industry Sales for 20 Years *($/yr)* [1]	**TOTAL EFFECTS: Average Annual Changes from Baseline Forecast** Change in All Jobs *(FTEs)* [2]	Change in Construction Jobs *(FTEs)* [3]	Change in State GDP *($/yr)* [4]	Change in Industry Sales Output *($/yr)* [5]	Change in Net State Revenue *($/yr)* [6]
Utility Sales	Plus $10 million	366.7	102.7	$76,552,858	$130,016,025	$3,689,000
	Minus $10 million	-351.3	-93.0	-$74,569,768	-$11,441,788	-$3,675,500
Business Services Sales	Plus $10 million	140.0	7.4	$8,831,563	$13,399,045	$220,500
	Minus $10 million	-125.1	2.2	-$6,884,750	-$10,448,045	-$204,500

ECONOMIC IMPACT ASSOCIATED WITH ADDING A COMBINED-CYCLE GAS TURBINE GENERATING PLANT IN CONNECTICUT

In one of the IRP scenarios, we evaluate the economics of building a new natural gas combined-cycle gas turbine plant in Connecticut. This plant would be built in the state prior to need and would not necessarily displace any new generating capacity in New England. Adding such a plant is expected to affect the wholesale market prices for electricity, particularly the locational marginal prices in Connecticut. The impact of those market price changes in turn affects customer costs, which are captured in the IRP metrics and discussed further below.

We assume that construction of the new plant begins in 2015 and lasts two years with operation commencing in 2017. The plant's assumed operating capacity is 656 MW. The plant is highly efficient, requiring a small (~30 people) workforce to operate and maintain. While the plant may operate for 30 years or more, we have limited the simulation to the first 20 years of operation through 2036.

Figure 7 shows the results of the simulation separated into the construction and operational phases of the new gas plant. The construction period (2015-2016) shows a significant impact because of the magnitude of construction spending and temporary jobs associated with the construction. During the first 20 years of operation, from 2017 through 2036, the plant receives revenue from the market and interacts with the regional economy to create jobs, taxes, and new sales in all industries.

Figure 7
Economic Impact Metrics for the CCGT Build and Operation

	TOTAL EFFECTS: Average Annual Changes from Baseline Forecast					
	Change in All Jobs *(FTEs)* [1]	Change in Construction Jobs *(FTEs)* [2]	Change in Utility Sector Jobs *(FTEs)* [3]	Change in State GDP *(2010 $m/yr)* [4]	Change in Industry Sales *(2010 $m/yr)* [5]	Change in Net State Revenue *(2010 $m/yr)* [6]
Construction Phase (2015-2016)	2,689	1,817	n/a	$188.4	$312.2	$35.4
Operational Phase (2017-2036)	104	13	30	$31.8	$54.0	$0.9

The construction period (2015-2016), with its significant spending, creates a large number of jobs. We assume the construction cost is divided between labor (47%) and materials and equipment (53%). Labor spending accrues to the 'non-residential manufacturing structures' sector and material and equipment spending accrues as the producer's durable equipment investment in the 'Electrical transmission, distribution and industrial apparatus' sector. To the extent that Connecticut suppliers can satisfy the demand for the required material and equipment, they do; otherwise the spending on materials flows out of state and import of the remainder of the required materials and equipment occurs.

During the operational period, the plant receives significant amount of revenues from electricity sales. However, most of this revenue accrues to expenditure for fuel and leaves the state. We therefore simulate the operational phase by assuming that the plant requires 30 workers (net new direct FTE jobs).[7] These direct jobs in turn create (through interaction with the regional economy) an average of 74 indirect and induced jobs each year. State GDP increases on average $31.8 million each year and new sales in all industries increase $54 million on average each year over the 20-year operational period. Net state revenue increases $0.92 million on average each year and is the difference between revenue from all domestic state sources and spending for all domestic state uses.

Since we assume that the gas plant is added before the market needs the capacity, the associated effects may simply be advancing in time the employment and economic activities compared to the counterfactual case of building it in some later year. However, if the counterfactual case were to add a similar plant in a different state and thereby eliminate the eventual need to build such a plant in Connecticut, then the associated impact estimated above would be net new economic activity.

[7] See for example the analysis by the Economic Development Research Group for the proposed Brocton, MA plant at http://brocktoncleanenergy.com.s68855.gridserver.com/cms/wp-content/uploads/090929-Economic-Assessment-_Final11.pdf and Erickcek, George A. (2000). "Economic Impact of the Proposed CME North American Merchant Energy, LLC Gas-Powered Electric Power Plant on Berrien County," Kalamazoo, MI: W.E. Upjohn Institute for Employment Research. http://research.upjohn.org/reports/109

ECONOMIC IMPACT ASSOCIATED WITH THE COST OF ELECTRICITY

In addition to spending on renewable energy projects, energy efficiency programs, and a new gas plant (described above), the overall resource portfolio in each IRP scenario will affect the price of electricity that consumers pay. For each Resource Scenario, the changes in the cost of electricity to homeowners represent changes in their purchasing power. We assume that as the cost of electricity increases, homeowners reduce their spending in other areas to compensate for their additional spending on electricity. The converse is true also.

When the cost of electricity increases relative to other fuels used in commercial and industrial sectors' business processes, the economic model allows for substitution between electricity and other fuels. In addition, if the cost of electricity for commercial and industrial customers increases, the results show that the economy shrinks, and the converse is also true. However, specifying changes in the cost of electricity to industrial and commercial users does not directly alter employment in the utilities sector through a price elasticity response. For instance, if the cost of electricity increases for commercial and industrial users, we do not assume in this analysis that there is a change in the demand for electricity, or employment in the utility sector.

Figure 8 below shows the estimated effects associated with changing electricity prices to residential, commercial, and industrial customers in Connecticut. The first three rows show the estimated impact associated with increasing the cost of electricity by $100 million per year and the latter three rows show a decreasing cost of $100 million per year.

Figure 8
Economic Impact of Cost of Electricity

	Changes Simulated	**TOTAL EFFECTS: Average Annual Changes from Baseline Forecast**			
	Annual Change in Industry Sales for 20 Years *($/yr)* [1]	Change in All Jobs *(FTEs)* [2]	Change in State GDP *($/yr)* [3]	Change in Industry Sales Output *($/yr)* [4]	Change in Net State Revenue *($/yr)* [5]
Residential	Plus $100 million	-334.9	-$41,623,442	-$71,658,342	-$2,485,500
	Minus $100 million	352.4	$44,099,006	$75,879,553	$2,506,500
Industrial	Plus $100 million	-1,145.4	-$292,099,507	-$514,403,941	-$10,983,000
	Minus $100 million	1,279.5	$326,978,356	$575,961,059	$12,240,500
Commercial	Plus $100 million	-881.4	-$152,647,318	-$242,232,064	-$6,051,000
	Minus $100 million	936.7	$162,374,240	$257,674,108	$6,209,500

SUMMARY OF ECONOMIC IMPACTS

While the incremental job and macroeconomic impact of various activities are simulated and estimated independently, we aggregate the overall effects for each relevant IRP scenario in Figure 9 below. As described above, the effects simulated include the impact of investing in renewable energy projects in Connecticut (through the use of Class I ACPs), the spending associated with energy efficiency programs, and the building of a new power plant in Connecticut. As shown, we estimate that the most positive employment impact relative to the IRP's Base Case is associated with Expanded EE scenario. The estimated incremental 5,507 FTE jobs associated with Expanded EE is mostly due to the program spending and the estimated reduction in electricity costs to consumers. In the two renewable energy scenarios, the net job effects are modest compared to the Base Case and compared to the Expanded EE scenario. To illustrate the potential effects of increasing flexibility in meeting Class I renewable requirements, we analyze a policy that would allow up to one quarter of the current Class I requirement to be met through expanded energy efficiency programs. As shown in Figure 9 below, allowing some flexibility Class I requirements would result in lower electricity costs, additional spending on energy efficiency programs, decrease in ACP payment and the associated use of the ACP. On net, Expanded Energy Efficiency with Class I RPS Flexibility scenario would support approximately 6,100 more jobs than in the Base Case.

Figure 9
Summary of Economic Impacts

	TOTAL EFFECTS: Average Annual Changes from Baseline Forecast				
	Change in All Jobs *(FTEs)* [1]	Change in Construction Jobs *(FTEs)* [2]	Change in State GDP *($/yr)* [3]	Change in Industry Sales Output *($/yr)* [4]	Change in Net State Revenue *($/yr)* [5]
Full Renewables					
Solar PV Maintenance and Repair	-480	-326	-$63	-$95	-$3
Fuel Cells Manufacturing	-334	0	-$39	-$79	-$1
Electricity Cost Related	1,245	0	$230	$380	$9
Total	**430**	**-326**	**$128**	**$206**	**$5**
Low Renewables					
Solar PV Maintenance and Repair	468	317	$62	$93	$3
Fuel Cells Manufacturing	323	0	$37	$77	$1
Electricity Cost Related	807	0	$149	$246	$6
Total	**1,598**	**317**	**$248**	**$416**	**$10**
Expanded EE					
Solar PV Maintenance and Repair	-149	-101	-$20	-$30	-$1
Fuel Cells Manufacturing	-104	0	-$12	-$24	$0
Electricity Cost Related	4,207	0	$776	$1,284	$31
Energy Efficiency Programs	1,553	759	$193	$319	$10
Total	**5,507**	**658**	**$938**	**$1,549**	**$40**
Expanded EE w/ Class I Flexibility					
Solar PV Maintenance and Repair	-480	-326	-$63	-$95	-$3
Fuel Cells Manufacturing	-334	0	-$39	-$79	-$1
Electricity Cost Related	5,404	0	$997	$1,649	$40
Energy Efficiency Programs	1,553	759	$193	$319	$10
Total	**6,143**	**433**	**$1,089**	**$1,795**	**$46**
New COS Gen, Hi MOP					
New COS Generation (Construction)	2,689	1,817	$188	$312	$35
Total During Construction Phase	**2,689**	**1,817**	**$188**	**$312**	**$35**
New COS Generation (Operation)	104	13	$32	$54	$1
Electricity Cost Related	210	0	$39	$64	$2
Total During Operation Phase	**315**	**13**	**$70**	**$118**	**$2**

ECONOMIC IMPACT OF NEW STATE BONDING

We also estimate the economic and fiscal impact (costs only) of new state bonding as another metric to assess the role the state might play in subsidizing or otherwise incentivizing some of the activities described above. The analysis looks at the new debt service on a bond issue of $10 million. We assume the interest rate is 5.3% for 20 years. The level debt service payment required is $822,963 in nominal terms over 20 years. To simulate new debt service, we reduce state government spending across the board by the debt service requirement. We assume the state does not raise taxes to cover the required payments, but rather reallocates spending to accommodate the new expense. We assume this takes the form of deferred or forgone hiring and/or project spending for example.

Figure 10 shows the results of the simulation. The most significant reduction in employment occurs in the public sector as hiring is deferred or forgone. Decreased state government spending ripples through the economy and reduces slightly the sales and taxes paid in all industries, as well as personal incomes and the taxes related to personal income and household consumption.

Figure 10
Economic and Fiscal Effects of New Debt Service

	TOTAL EFFECTS: Average Annual Changes from Baseline Forecast				
	Change in All Jobs *(FTEs)* [1]	Change in Private Non-farm Jobs *(FTEs)* [2]	Change in State GDP *($/yr)* [3]	Change in Industry Sales Output *($/yr)* [4]	Change in Net State Revenue *($/yr)* [5]
Debt Service on $10 million @ 5.3% for 20 years	-12.9	-3.6	-$3,298	-$1,569,213	-$55,500

THE REMI MODEL

The Connecticut REMI model is a dynamic, multi-sector, regional model developed and maintained for the Connecticut Center for Economic Analysis by Regional Economic Models, Inc. of Amherst, Massachusetts. This model provides detail on all eight counties in the State of Connecticut and any combination of these counties. The REMI model includes all of the major inter-industry linkages among 466 private industries, aggregated into 67 major industrial sectors. With the addition of farming and three public sectors (state and local government, civilian federal government, and military), there are 70 sectors represented in the model for the eight counties.[8] For more information on the REMI model, please refer to its website at http://www.remi.com.

[8] The seminal reference is George I. Treyz (1993), Regional Economic Modeling: A Systematic Approach to Economic Forecasting and Policy Analysis, Kluwer Academic Publishers, Boston.

APPENDIX J

PUBLIC COMMENTS

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SIGNIFICANT PUBLIC COMMENTS AND RATIONALE FOR CHANGES TO THE 2012 IRP

On September 19, 20, and 22, 2011, the Department conducted a series of meetings to obtain stakeholder feedback on the scope of the IRP during the development of the draft. A draft of the IRP was issued by the Department on January 20, 2012, together with a notice inviting written comments over a 45-day period. DEEP conducted a technical meeting on February 1, 2012 at 10:30 a.m. at its offices at Ten Franklin Square, New Britain, Connecticut, to provide for public review and comment on the 2012 draft IRP. The technical meeting continued on Wednesday, February 6, 2012, at 1:00 p.m. dedicated to the expanded electric C&LM program proposed in the draft IRP. On March 2, 2012, DEEP conducted a public hearing at its offices to enable the public to comment on the draft IRP and the expanded electric C&LM program.

In March 2012, DEEP issued a revised schedule for the IRP proceeding reflecting its intention to issue a revised draft IRP for public comment before issuing the final IRP. This additional draft circulation and comment period was not legally required, but at the time of developing the schedule, DEEP announced this additional process in the event that new analysis or policy recommendations might be developed after the release of the first draft that would benefit from additional public review and comment. However, no material analysis has been conducted since the draft IRP was issued that alters the findings and recommendations in the final IRP, and that would benefit from additional public comment. Given that the statutory deadline for completion of the 2012 IRP was January 1, 2012, and for the reasons described above, DEEP has therefore determined that the circulation of a revised draft and additional comment period is no longer needed.

DEEP received 28 sets of written comments on the draft IRP, representing the views of the following entities: Woodlands Coalition, Environmental Energy Solutions (EES), Sierra Club, Connecticut Fund for the Environment (CFE), AARP Connecticut, Clean Water Action, Connecticut Industrial Energy Consumers (CIEC), Connecticut Business and Industrial Association (CBIA), Connecticut Energy and Advisory Board (CEAB), the Connecticut Light & Power Company/Yankee Gas (CL&P), Class III CHP Organization, Eastern Connecticut State University (ECSU), CPV Towantic, LLC, Connecticut Siting Council (CSC), ENE, Northeast Energy Efficiency Partnerships (NEEP), NEPGA, the Office of Consumer Counsel (OCC), the United Illuminating Company (UI), NRG, United Technologies Corporation Power (UTC Power), Renewable Energy New England (RENEW) and the Conservation Law Foundation, ClearEdge Power, Inc., Coalition for Renewable Natural Gas, Inc., Constellation Energy Commodities Group, Inc. and Constellation NewEnergy, Inc. (CNE), Naugatuck Energy Development, LLC and approximately 500 Connecticut Residents. All written comments submitted on the 2012 IRP, and recordings of the February 1, 2012 and February

26, 2012 technical meetings and the March 2, 2012 Hearing are available on the DEEP website.[1]

Most of the written comments focused on six key issues: the expanded savings scenario from the C&LM Plan; flexibility in regard to the states renewable portfolio standard (RPS) requirements; transmission; increased generation including combined heat and power (CHP) and repowering of certain generation assets. Some comments also related to the forecast assumptions used in IRP and energy security. This section contains a summary, organized by topic, of major comments and DEEP's responses, and the rationale for changes made to the 2012 IRP.

Expanded Savings Scenario

The majority of the submitted comments supported expanding energy efficiency activity in the state. Participants cited different reasons for supporting expanded efficiency. Many participants expressed caution with certain aspects of expanded energy efficiency plan.

CPV Towantic LLC, CEAB, NRG and OCC indicated their concern about the ability to achieve the targeted level of savings assumed in the IRP. They believe the IRP may overstate energy efficiency savings by not including the possibility of diminishing returns. OCC also points out that the ramp-up of the programs will delay the achievement of the assumed savings levels in the Expanded Energy Efficiency scenario analysis, and this is not reflected in the forecast. Further, lower than expected natural gas prices may affect the actual demand for and cost-effectiveness of the energy efficiency programs relative to forecast.

OCC recommended that the 2012 draft IRP be amended to increase program budgets by no more than 50% in 2012 and 2013; OCC also recommends carefully tracking and monitoring the progress of the C&LM programs. EES supports all cost-effective energy efficiency, but warns that success is uncertain. EES suggests that more research should be undertaken by DEEP on customer's willingness to finance efficiency measures. CBIA strongly supports increased energy efficiency but wants the energy conservation and load management programs to be further optimized or reinvented as market-based. EES also warned about accuracy of price assumptions used in potential studies.

Some participants also expressed concern about ratepayer impacts from expanded energy efficiency. AARP stated that the draft IRP lacks sufficient analysis to support Sections 89b(2), 89c(2), 90, and 90a(3) of Public Act 11-80. AARP asked that the draft IRP be revised to identify the mix of policy approaches that would expand energy efficiency at least-cost, reach the underserved, evaluate an alternative expanded energy efficiency for mix of changes in code, appliance standards, new program design and increased funding. CEAB

[1] Written comments are available at
http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=1&Count=30&Expand=2.3.1&Seq=5
The recording of the technical meeting is available at
http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=1&Count=30&Expand=2.2.1&Seq=3

believes that the IRP is too narrowly focused on a large-scale expansion of energy efficiency. CEAB also expressed concern about the rate impact of expansion, especially for non-participants of the C&LM programs and low income residential customers.

NEEP indicated the electric distribution companies (EDCs) should have control over the specifics of the energy efficiency programs they offer.

ENE believes that PURA may need to rescind past Final Decisions for previous integrated resource plans initiated prior to legislative changes to the process in P.A. 11-80, to the extent that those decisions state that a resource need must exist in order to take on additional energy efficiency. ENE also expressed concern that some of the figures included in the IRP do not show the full extent of predicted savings from EE.

DEEP shares many of the same concerns as the participants regarding the uncertainty of achieving the target savings levels outlined in the plan, and remains committed to overcoming many of the challenges expressed in the comments. DEEP will work closely with program administrators and other stakeholders to ensure that the ramp-up of the programs is implemented successfully and that any barriers that emerge along the way are addressed promptly.

Energy efficiency offers significant benefits and should be expanded because more conservation will provide significant savings to customers, by helping reduce their electric bills. A sustained commitment to delivering energy efficiency programs at the all cost-effective level is expected to create 5,500 jobs in Connecticut by 2022. Additional conservation can also provide benefits to the electric system, the environment and the local economy.

DEEP believes that the expansion of energy efficiency called for in the IRP is supported by the statutory requirement set forth in Section 16a-3a of the General Statutes of Connecticut, that "resource needs shall first be met through all available energy efficiency and demand resources that are cost-effective, reliable and feasible." DEEP also believes that the expansion of energy efficiency is necessary to achieve the goals set forth in Public Act 11-80 which include reducing rates and decreasing costs for Connecticut's ratepayers. Additional energy efficiency is also necessary to comply with requirements in Section 33 of the Act that mandates weatherization of 80% of Connecticut's residential housing units by 2030, and the requirement to reduce energy use in state-owned or leased buildings by 10% by January 1, 2013 and an additional 10% by 2018.

Regarding the pace at which programs would be ramped up to all cost-effective spending; DEEP agrees that the pace must be carefully controlled to ensure that program quality and cost-effectiveness are maintained during the ramp up. DEEP also agrees with OCC that additional program spending must be carefully tracked and monitored to ensure that program quality and customer satisfaction are also maintained.

Flexible Class I RPS

Another section of the draft IRP that received a considerable amount of comments was the discussion on the challenges in meeting the states' future renewable portfolio standard (RPS) requirements. Specifically, a number of comments related to the recommendation in the draft IRP to consider adding some flexibility in meeting future class I RPS requirements. Overall, there was a mixed reaction to this recommendation.

The following entities expressed some support, in varying degrees, for increased flexibility in meeting RPS requirements: OCC, Renewable Natural Gas, CBIA, CEAB, Constellation, ClearEdge, Kimberley-Clark, Ansonia Gen, CIEC and AARP.

OCC indicated its support of out-of-region large scale hydropower, allowing new energy efficiency resources to meet a portion of the Class I RPS requirements and allowing distributed generation (DG) to satisfy a portion of Class I RPS requirements. AARP believes that DEEP should evaluate the costs and benefits of revising the RPS to allow hydropower from new projects greater than 5 megawatts to qualify as an eligible Class I resource. DEEP should also study in greater detail the pros and cons of allowing energy efficiency and new large hydropower to qualify as Class I under the RPS.

While CEAB indicated its support of a potential reduction in Class I RPS requirements, it believes allowing new energy efficiency to count as a Class I resource would make the RPS meaningless. Similarly, Renewable Natural Gas supported inclusion of bio-methane for Class I eligibility. However, RNG does not support the use of energy efficiency as Class I.

Kimberley Clark proposed that Connecticut allow microgrids, including CHP resources qualifying for Class III, to qualify as Class I, or in the alternative, satisfy a portion of the Class I requirement. Further, including energy efficiency in the Class III market decreases the REC prices, which provide no incentive for further development of these resources. CIEC and CBIA and ClearEdge also indicated its support of a similar construct in the RPS requirements. CBIA added that meeting RPS is far too expensive without the benefit of creating jobs in Connecticut.

The following entities opposed increased flexibility in meeting RPS requirements: EES, 500 residents, Sierra Club, Clean Water Action, CFE, RENEW, NEPGA, UTC, ENE and NEEP. ENE believes DEEP should clarify its recommendations regarding Class III resources and whether new resources would receive RECs and if the recommendation is in response to Sections 129 of PA 11-80. ENE disagreed with DEEP's flexibility approach - it ignores the need to pursue efficiency and renewable energy. ENE believes DEEP should seek to meet RPS with regional resources while attempting to maximize in-state resources. Further, New England states should promote long-term contracting through EDCs. EES cautioned against changing the RPS requirements based on a short term forecast as well as the use of EE or imported hydropower to meet Class I RPS. EES suggested an alternative, such as the implementation of "trigger point" legislation that would allow change to the RPS goals if it becomes clear that a near-term goal won't be met.

UTC believes the substitution of 25% of Class I RECs by Class III RECs would further decrease the amount of Class I generation that could be installed and operational within Connecticut. NEEP echoes a similar concern, stating that including energy efficiency in the

RPS could result in less renewable energy and less energy efficiency. NEEP believes that energy efficiency initiatives will take place whether they are part of the RPS or not.

Sierra Club recommended keeping RPS "as is" because there is ample renewable potential in the region, and instead focus on supporting transmission and increased capacity factors. The IRP should also consider increasing the alternative compliance payment (ACP). CFE indicated in its comments that reducing the RPS requirement would have adverse impact on incentives to build Class I generation. CFE believe the draft IRP overstates the rate impact of retaining the current 20% RPS requirement. CFE, NEPGA and Constellation all opposed allowing large hydropower and new energy efficiency to count towards Class I RPS requirements. Constellation also advocated for consistent policy regarding RPS and suggested DEEP consider increasing the ACP but delay implementation and ramp-up of the ACP. RENEW recommends long-term contracts with renewable generators to meet RPS goals

After reviewing the comments, DEEP decided not to recommend any changes to the RPS at this time. Connecticut is currently meeting its Class 1 PRS requirements and a shortage is not expected for till 2018. The situation could improve due to changes in financial markets, government action or improvements in the cost of renewable power. DEEP will work to meet the current goals but will study alternatives and carefully monitor progress. DEEP may recommend changes to the RPS in the future if the Class I RPS requirements and environmental goal are not being met at a reasonable cost to ratepayers.

Transmission

Some of the participants commented on the transmission discussion in the draft IRP. Specifically, most of the discussion related to some of the assumptions used in the resource adequacy section of the draft, as well as the suitability of using non-transmission alternatives (NTAs) to meet some of the resource needs.

ENE is encouraged by recent regional discussions surrounding NTAs. ENE indicated concern that a pending NTA analysis for central CT/Hartford will not yield process changes for market alternatives or recommendations regarding which NTA to pursue. NEPGA also indicated its support of NTAs and active role for CT in ISO-NE NTA process. CEAB also indicated the draft IRP placed too much emphasis on expansion in the transmission system. NRG argued that the viability of the New England East West Transmission Solution project (NEEWS) should have been evaluated not assumed, and a comparative economic cost analysis of the proposed transmission project against other resource options, such as NTA's should have been performed. NRG also discussed the growing burden of transmission costs to consumers, noting transmission costs are forecasted to double from 2011-15, from 1.2 cents to 2.1 cents per kWh. Sierra Club believes the draft IRP overestimates transmission costs.

DEEP has determined that it would be premature to judge the NTA analysis for CT/Hartford that will be done by ISO-NE. DEEP believes that the course that has been set to seek meaningful input and participation in the ISO-NE process has significant potential to improve the NTA process and must be fully pursued. NRG's points regarding NEEWS were carefully considered when the DEEP set up the process for the IRP. Upon review, DEEP concludes

that its parameters for determining what projects were in and which projects were out in the Base Case was the most objective manner in which the analysis could be carried out. DEEP stands by its determination that NEEWS will be a critical component providing reliability to the system when it is completed. As stated in the IRP, until the uncertainties surrounding the Interstate and Central Connecticut component of NEEWS are resolved, DEEP will continue to monitor the supply, demand, and transmission situation and assess whether any local resource adequacy shortfalls could occur. With regards to the Sierra Club's concerns regarding transmission costs, DEEP believes its estimates for transmission costs are reasonable, based on the work done to date. DEEP acknowledges that the work being done by NESCOE and other parties in New England will allow further analysis to be done on transmission costs, and that those estimates can be used in the next IRP.

Increased generation (CHP, Repowering)

Although the IRP not identify a need for additional generation capacity, several participants commented on the advantages of adding distributed resources, such as CHP or repowering units over time. Ansonia Generation, Kimberly-Clark, ISE, UTC CFE, Clean Water Action and EES supported the use of CHP and other distributed generation as part of a renewable energy strategy and/or microgrid infrastructure. Kimberly-Clark proposed inclusion of CHP to qualify as or satisfy a portion of Class I to fulfill the objective of having in-state development of renewable energy. Ansonia Generation specified that Section 94 of the Act provides a vehicle for DEEP to initiate generation and procurement process to identify potentially eligible new generators

Towantic believes DEEP should still begin the process of considering new generation due to aging infrastructure and the long lead time involved in developing new resources. NRG echoed a similar concern regarding the long lead times. NEPGA suggested future long-term generation needs be met through a competitive bidding process.

DEEP supports CHP development. Connecticut has a number of incentives for CHP. In response to the comments, DEEP has analyzed the Class III RPS market and agrees that there is an oversupply situation which will likely get worse. DEEP recommends changes that will stabilize the market and provide better incentives to support existing CHP resources and new development. The 2012 IRP concluded that no new generation was needed and that new generation or repowering would not reduce rates during the study period. None of the comments have persuaded DEEP to change its conclusions. DEEP will monitor the supply/demand balance and will take action if the situation changes and reliability is jeopardized.

Forecast Assumptions

DEEP received several comments raising concerns about the assumptions used in forecasting the 2012 IRP.

AARP does not believe that electric capacity prices will drop as low as the draft 2012 IRP projects nor rise as rapidly. According to AARP, the 2012 IRP also understates the amount of available demand response (DR) throughout the planning period. AARP believes that

projected REC values from 2017 and beyond may be too high, and that projected CO2 prices in 2018 and beyond may be too low.

DEEP's estimates are, of course, subject to market uncertainties. The projected CO2 prices reflect regional greenhouse gas initiative (RGGI) and an extension of RGGI. A federal climate policy could increase the price, but the prospect of a federal program does not appear to be within the study horizon of the IRP.

CSC indicated that it has received and granted three requests from generators recently to decommission their facilities for the use of alternate fuels, this eliminating their dual fuel capability. In two of these cases, the generators have consulted with ISO-NE and agreed to retain the necessary equipment on-site in order to switch back within a matter of months, should the need arise. DEEP appreciates the information offered by CSC. It has considered the impact of said generators in the forecast and has determined the availability of these particular generators in the winter months will not cause a resource need in the base case. However, it presents a potential alarming trend that will warrant close monitoring by DEEP.

CPV believes that DEEP understated retirement in the region, in part by ignoring the Clean Water Act (CWA). Additionally, CPV believes that renewable build and demand response is overstated in the IRP forecast. CPV asked that DEEP reconsider keeping capacity imports the same because there are no contracts. NRG echoed the same concern regarding retirements, insomuch as DEEP failed to consider the Clean Water Act's impact on retirements. DEEP notes that the IRP analysis does not include specific requirements or costs associated with the CWA, as explained in Appendix E. However, the "Tight Supply" future utilized in the IRP was conducted to assess the implications of supply-demand challenges such as additional retirements. The renewables assumptions are explained in detail in Appendix D. The demand response assumptions are explained in Appendix B. As noted, the amount of demand response assumed does not significantly exceed the amount that has already cleared in FCM auctions, until 2021. DEEP uses the same capacity imports assumptions. See Appendix B.

RENEW believes the draft 2012 IRP underestimates potential for retirements of older, inefficient units by ignoring the current and future market circumstances related to these units operation. DEEP notes that accurately predicting unit retirements is difficult because of: environmental rules and market conditions, uncertainties about individual EGUs' characteristics, and uncertainties about market participants' criteria for retrofitting or retiring plants. Fortunately, the effect of errors in the retirement analysis (e.g., because of missing environmental compliance costs) tend to be somewhat mitigated by the effect incremental retirements have on market prices.

Clean Water Action and Sierra Club proposed using stricter National Ambient Air Quality Standards (NAAQS) in order to prioritize the most efficient and cleanest resources at the top of the ISO-NE dispatch order. The basis for DEEP's allowance cost assumptions is explained in Appendix E. Note that the cleaner resources are already strongly favored over the dirtiest because of the low price of natural gas, so emissions remain far below historic levels. Higher allowance prices could decrease emissions even further.

CBIA indicated a desire to see more attention be given to a longer range forecast (10 or 15 years) for energy resources. DEEP agrees with the importance of long-term planning and notes that as part of the comprehensive energy strategy, which is currently underway, it is looking out at a much longer time frame than the draft IRP, out to 2050.

OCC believes the gas price forecast should be updated. Additionally, the energy savings/demand savings estimates and associated net benefit calculations are far too optimistic. The net benefits of energy efficiency will also change as a result of changing natural gas price changes. DEEP notes that this topic was discussed during the February 1, 2012 technical meeting. At that time, spot gas prices were a full dollar below the prices assumed in the base case. DEEP indicated that it was not inclined to change the forecast at the time as it believed the price reduction was temporarily and reflective of a very mild winter rather than a shift in long-term shift in fundamentals. DEEP maintains its earlier position and will not revise the gas price forecast at this time.

Energy Security

EES provided a discussion on energy security and the implication for the State. EES identified the following threats to energy security, among other things: fuel supply interruption/cost escalation, physical security of generation, transmission, distribution, and control technology (SCADA), natural disasters, foreign dependency via disruption of globalized supply chains for critical grid components (GSUs, etc.), cyber threats including distributed denial of service, hacking, electromagnetic pulse (including coronal mass ejections), embedded codes in foreign sourced components and weaknesses in SCADA/IPC, a combined or "blended" combination of the aforementioned threats, other threats and consideration including “unintended consequences” of unrelated actions. EES points out that the IRP, if it is truly “integrated”, is the proper venue for visioning security implications of grid design and additions rather than after such events may occur.

Pursuant to the recently passed Public Act 12-148, An Act Enhancing Emergency Preparedness and Response, the Commissioner of DEEP will direct the preparation of a comprehensive plan and program for the civil preparedness of the state, for approval of the Governor, and integrate and coordinate that plan and program to the fullest extent possible with the civil preparedness plans of the federal government and of other states. Also pursuant to Public Act 12-148, PURA will initiate a docket with the express purpose of developing industry specific standards for acceptable performance by each utility in an emergency, and in a separate proceeding, for intrastate telecommunications services. DEEP intends to work closely with stakeholders, and responsible agencies to ensure success in implementing these directives.

In addition to the tasks that will be carried out pursuant to Public Act 12-148, PURA is currently conducting a proceeding to address the utilities response in the recent storms in Docket No. 11-09-09, PURA Investigation of Public Service Companies Response to 2011 Storms. Further, PURA is proactively engaged in reviewing and approving each public service company’s emergency response plans as well as more specific plans through a docketed proceeding conducted periodically. See; Docket No. 11-05-22, DPUC Review of Updated Emergency Plans. In rate proceedings, PURA reviews areas of operations such as

tree trimming, overtime and whether the utility is maintaining personnel. PURA is currently engaged in cyber security planning via its ongoing Docket No. 10-11-08, DPUC Determination of a Public Service Company-Specific Cyber Security Policy. PURA's gas pipeline safety group is responsible for pipeline safety in Connecticut and consists of a team of professionals dedicated solely to this function.

Planning related to fuel supply disruptions, fuel diversity issues and effect on the regional electric grid is under the jurisdiction of the ISO-NE, New England's regional grid operator. DEEP remains committed to working with ISO-NE to provide ongoing solutions on behalf of Connecticut.

Other Comments

Participants raised several additional comments on varied topics. For example, NRG submitted comments predicting that in the near future, there would be a significant number of retirements of older, dirtier generators, and that these retirements present a well-timed opportunity to supplant these aging plants with cheaper and cleaner generation. NRG indicates that it is willing to respond to an RFP for repowered and new generation with a 40 MW clean wood biomass, a repowering of an existing boiler at the NRG plant in Montville, among other generating projects. NRG asserted that its proposed project would create significant environmental, as well as economic benefits.

The IRP notes that a large Class I biomass project could provide a significant contribution to renewable generation in the state to help meet RPS goals later in the decade. DEEP believes that the current surplus of generation presents a timely opportunity to explore possible avenues to develop in-state renewable generation, such as an RFP for long-term generation contracts, or other mechanisms under existing statutes.

CFE urged its support of retirement of the Bridgeport Harbor 3 power generation plant. This was mentioned by several participants in the proceeding, including the petition of 500 Connecticut residents. An electric generation facility is privately owned and the decision of whether that plant retires or continues to operate is not within the jurisdiction of the state of Connecticut. DEEP notes that this plant has had a very low run rate in the last several years due to the current market dynamics, which has had a dramatic reduction in emissions.

Participants also raised several issues in their comments that DEEP found to be out of the scope of this proceeding. These comments are discussed as follows:

- UTC advocated avoiding use of LREC funding for Project 150, and outside of LRECs, there is no need for additional fuel cell incentives. The draft IRP should plan for expiration of Investment Tax Credit.

- NRG suggested that the draft IRP should consider components of consumer costs besides the generation service charge.

- NEPGA indicated its support of itemizing the public policy components of rate.

- Clean Water Action recommends DEEP use long-term energy and REC contracts to hedge prices and allow needed improvements to aging natural gas infrastructure. CBIA also stated its support of increasing the natural gas infrastructure. CIEC suggested that DEEP consider the expansion of the natural gas capacity release program.

DEEP will consider these issues, to the extent practicable, in the preparation of the state's Comprehensive Energy Strategy (CES) currently underway. DEEP encourages further participation by participants in the CES and welcomes the opportunity for further engagement in order to resolve these myriad issues