ISO new england

2005

Regional System Plan

ISO New England ● **Regional System Plan 2005**

The Executive Summary follows.
The attached CD contains the full report.

Approved by the ISO New England Board of Directors

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Executive Summary

ISO New England has completed its 2005 Regional System Plan (RSP05) for New England's electric power system and presents the results in this report. This Executive Summary highlights the major results of the 10-year plan and summarizes the ISO's conclusions and recommendations for the future development of the bulk power system.

RSP05 identifies system improvements needed over the next 10 years and provides information on what infrastructure improvements are needed and when and where they are needed to meet the system's peak demands in conformance with planning criteria. Plans for the region's future electricity infrastructure must account for the uncertainty of assumptions over the next 10 years in terms of load growth, fuel prices, new technology, market changes, environmental requirements, and other relevant events. As with previous planning reports, formerly called Regional Transmission Expansion Plans (RTEPs), RSP05 provides technical information and data on various scenarios and identifies the requirements for maintaining, improving, and ensuring the reliability of the system in the short term. The plan also assists in linking physical system needs to wholesale market mechanisms aimed at attracting market solutions (generation, demand response, etc.) to mitigate these needs. RSP05 thus is a broader plan of the region's electricity system needs than the previous RTEP reports.

RSP05 resource adequacy studies are consistent with previous RTEP findings that indicated the need for significant new generation or demand-side resources in New England in the 2008 to 2010 timeframe. Key findings of RSP05 are as follows:

- RSP05 identifies 272 transmission projects required for the reliability of the New England system. Previous RTEP reports emphasized the major 345 kV projects. RSP05 reinforces the need for the major 345 kV projects and places greater emphasis on the need for transmission projects throughout the system, particularly within load pockets.[1]
- Under high-demand conditions, New England will more likely be forced to operate under emergency conditions as soon as 2006 due to resource limitations in the Connecticut (CT), Southwest Connecticut (SWCT), and Norwalk/Stamford Subareas (NOR).[2]
- From a systemwide perspective, installed capacity (IC) projections show that additional resources are needed to meet systemwide demand as early as 2008 but no later than 2010.

[1] Load pockets are areas of the system where the transmission capability is not adequate to import capacity from other parts of the system, and load must rely on local generation.

[2] To conduct resource planning reliability studies within New England, the region is modeled as 13 subareas and three neighboring control areas. In addition to SWCT, NOR, and CT, these subareas include northeastern Maine (BHE); western and central Maine/Saco Valley, New Hampshire (ME); southeastern Maine (SME); northern, eastern, and central New Hampshire/eastern Vermont and southwestern Maine (NH); Vermont/southwestern New Hampshire (VT); Greater Boston, including the North Shore (BOSTON); central Massachusetts/northeastern Massachusetts (CMA/NEMA); western Massachusetts (WMA); southeastern Massachusetts/Newport, Rhode Island (SEMA); and Rhode Island bordering Massachusetts (RI). Greater Connecticut includes the CT, SWCT, and NOR Subareas. Greater Southwest Connecticut is comprised of the SWCT and NOR Subareas. The three neighboring control areas are New York, Hydro-Québec, and the Maritimes.

- Analysis of operating reserves shows the immediate need for approximately 1,100 megawatts (MW) of incremental quick-start resources or units with competitive energy prices in BOSTON and Greater Connecticut, especially in Greater Southwest Connecticut.[3] Adding 530 MW (of the 1,070 MW) in Greater Connecticut will meet this area's capacity needs and also serve to meet systemwide needs.

- The region must convert 400 MW of gas-fired generation to dual-fuel capability (i.e., having the flexibility and storage capacity to use oil as well as gas) by winter 2006/2007 and increase that capability by 250 MW per year through winter 2008/2009 and 500 MW more in winter 2009/2010.

Introduction to ISO New England

ISO New England is a not-for-profit corporation created in 1997. It is responsible for operating New England's bulk power generation and transmission system, overseeing and administering the region's wholesale electricity markets, and managing the regional bulk power system planning process. In February 2005, the ISO began operating as a Regional Transmission Organization (RTO). The ISO is submitting RSP05 in compliance with its Federal Energy Regulatory Commission (FERC)-approved tariff, *Electric Tariff No. 3, ISO New England Inc. Transmission, Markets, and Service Tariff*.[4] In addition to complying with federal regulations, the ISO works closely with state regulators and stakeholders, including participants in the marketplace, to carry out each of its functions.

The six-state New England electric power system serves 14 million people living in a 68,000 square-mile area. The system is fully integrated, using all regional generating resources across state boundaries. Over 350 generating units produce electricity, representing approximately 31,000 MW of generating capacity, connected to approximately 8,000 miles of high-voltage transmission lines. Most of these lines are fairly short and networked as a grid, resulting in close interrelationships of electrical performance in all corners of the system. Twelve transmission ties interconnect New England with neighboring electricity systems in the United States and Canada, including New York, New Brunswick, and Québec; these lines carry power into or out of New England depending on system needs.

Approach to Planning

RSP05 is a comprehensive assessment of the needs for producing and transmitting power in New England. Studies conducted for RSP05 projected energy use and load growth and analyzed the adequacy of installed and operable capacity in New England in terms of the amount and types of resources needed and when and where they will be needed to ensure the reliability of the system. It examined the need for additional dual-fuel capability and where such additions are needed. The ISO also simulated future air emissions from the region's generators and compiled information related to a potential regional carbon dioxide (CO_2) emission cap and other environmental regulations. Additionally, studies were conducted with the transmission owners to evaluate transmission system improvements needed for satisfying reliability requirements throughout New England. These studies identify major transmission upgrades as well as other required improvements. The ISO also examined system conditions to identify transmission improvements for enhancing market efficiency.

[3] Quick-start capacity is typically comprised of pumped storage and conventional hydro units, combustion turbines, many load-response (i.e., load-reduction) program resources, and internal combustion units that can start up and be at full load in less than 30 minutes. These units provide greater operating flexibility in daily operations and in emergency situations than base-load generators, which are available at all times to serve load, or generators that are available to serve intermediate load levels. In daily operations, quick-start resources can help replenish the capacity lost due to a sudden and unexpected loss of a generating unit or transmission facility. Under severe peak-load conditions, quick-start units can help avoid the need to implement involuntary load shedding by providing either energy or operating reserves.

[4] See <http://www.iso-ne.com/regulatory/tariff/index.html>.

As part of the RSP05 effort, the ISO consulted with stakeholders about numerous topics, including analysis of data trends, possible future developments, and options related to the region's short- and long-term electricity supply. The ISO met with the Planning Advisory Committee (PAC) eight times in 2005 to fully review RSP05 assumptions and study results. The PAC consists of participants in the electricity markets, transmission owners, representatives from government agencies, and consultants. The transmission projects are the result of an ongoing planning process among the ISO and New England transmission owners. This open stakeholder process has provided benefits to regional planning in terms of study priority, scope, and quality.

The ISO also fully participates with its neighboring electric power system control areas as well as interregional planning bodies, including the Northeast Power Coordinating Council (NPCC) and the North American Electric Reliability Council (NERC), to ensure the reliability and security of the wide-scale electric power system.[5] The ISO complies with all the NERC planning criteria and procedures (as well as all internal planning procedures) to enhance resource adequacy and transmission performance and to better coordinate the development of the interconnected power system in the Northeast.[6]

During 2004, the ISO signed the Northeast Planning Protocol, an agreement among ISO New England, the New York ISO (NYISO), and PJM Interconnection that commits the ISO and these transmission providers to cooperate in interregional planning studies.[7] The neighboring Canadian provinces participate on a limited basis to share data and exchange information. This overall cooperation is needed to improve the overall reliable and efficient operation of the electric power system in the northeastern United States and these provinces and to minimize interregional reliability problems. The protocol specifically aims to resolve interregional planning issues and identify the impacts that proposed generating units and transmission projects could have on neighboring systems. Additionally, the ISO participates in planning studies to ensure that contingencies in New England will not adversely affect neighboring systems.

Collectively, the results of the RSP05 studies, data gathering, and interregional coordinated study efforts provide the ISO with the information it needs to create system plans that market participants can use to develop market solutions or transmission improvements to meet system needs. The studies conducted are summarized below.

Projected Energy Use and Load-Growth Studies

To estimate demand, the ISO conducted energy and load-growth studies that forecasted energy and peak loads for 2005 to 2014. These forecasts considered data on historical demand, economic and demographic factors, weather, and projected reductions in energy use and peak loads based on conservation efforts and peak-load management (C&LM) programs. The analyses use data on "50/50" and "90/10" peak loads in New England. A 50/50 peak load has a 50% chance of being exceeded due to weather conditions, while a 90/10 peak load has a 10% chance of being exceeded due to weather conditions.[8]

[5] NPCC defines control areas as electric systems bounded by interconnection metering and telemetry that can control generation to maintain a net interchange schedule with other control areas and contribute to the frequency regulation of the interconnection. For further information, see <http://www.npcc.org/default.asp>. Also see <http://www.nerc.com/>.

[6] For more information on the ISO's planning procedures, see <http://www.iso-ne.com/rules_proceds/isone_plan/index.html>.

[7] PJM is the RTO for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and the District of Columbia.

[8] In the past 10 years, New England has exceeded the 90/10 peak load forecast under hot and humid weather conditions four times.

Resource Adequacy Studies

ISO New England relies on several types of studies to identify the resources required to meet future system reliability needs. The two frequently used studies are the installed capacity analysis and the operable capacity (OC) analysis. The IC analysis uses a well-established probabilistic method for determining the resources needed to meet a loss-of-load-expectation (LOLE) criterion that prevents the system from disconnecting firm load for a range of possible load levels and resource availabilities. The operable capacity analysis uses a deterministic method for identifying the amount of capacity needed to be operable to meet a specified peak load level including operating reserves. The OC analysis methodology is very similar to the approach system operators use to identify the resources needed on a daily basis to meet the expected peak-load conditions. Thus, installed capacity studies identify bulk power system reliability issues related to the adequacy of system resources, and operable capacity analyses identify reliability issues related to system security.[9]

Installed Capacity Analysis

When planning the generation system, ISO New England conducts an installed capacity analysis to identify an IC Requirement, or the adequacy of New England system resources and the amount of resources needed to meet an NPCC and ISO New England LOLE criterion.[10] To meet this criterion, the ISO must plan and install adequate resources for the New England bulk power system so that the probability of disconnecting firm customers due to resource deficiency will be no more than 1 day in 10 years.

The LOLE criterion has been used to determine New England's IC Requirement since 1971 when the New England Power Pool (NEPOOL) was charged to conduct regional planning.[11] This calculation assumes that no transmission constraints exist within New England so that all generating resources in the region are available to all loads. Other critical assumptions are as follows:

- The load forecast is modeled as a probability distribution of the weekday peak loads that accounts for the effects of weather uncertainty.
- The availability of resources is modeled based on the probability of forced outages.
- The transmission system can be operated reliably when systemwide operating reserves have been fully depleted.
- No generating units will be added or removed from the system during the assessment period.
- To meet emergency needs throughout the assessment period, New England can rely on 2,000 MW of uncontracted or otherwise unscheduled capacity (called tie benefits) from New York, Québec, and the Maritimes to meet needs.

[9] Reliability adequacy is a measure of the reliability of the bulk power system to meet demand and the sufficiency of the system's generating resources. Reliability security is a measure of the reliability of the bulk power system in terms of its ability to withstand disturbances arising within the system.

[10] Additional information on NPCC planning criteria can be found at: <http://www.npcc.org/criteria.asp>.

[11] NEPOOL was formed in 1971 by the region's private and municipal utilities to foster cooperation and coordination among the utilities in the six-state region and ensure a dependable supply of electricity. Today, NEPOOL members are ISO New England stakeholders and market participants. Over the next 18 months, the New England system stakeholders will review the methodology that calculates the IC Requirement.

- All ISO New England emergency actions per Operating Procedure No. 4, *Actions during a Capacity Deficiency* (OP 4), will be fully available during a capacity deficiency.[12]

Using this methodology and these assumptions result in identifying the minimum amount of capacity needed to meet the LOLE criterion. This is because these assumptions do not take into account the following risks, which, if present, would increase the IC Requirement:

- The New England transmission system may not be able to simultaneously transfer to load the full output from all of New England's generators. For example, Greater Connecticut is transmission limited, and power cannot always reliably or securely flow from a generator within that area to the load there. Also, the Maine–New Hampshire interface limits the receipt of generation output from Maine, including transfers from New Brunswick into New England.

- As shown by operating experience, transmission security (first- and second-contingency protection for thermal overloads, voltage collapse, and generator instability) cannot be maintained when New England-wide operating reserves do not meet the requirements stated in ISO New England Operating Procedure No. 8, *Operating Reserve and Automatic Generation Control* (OP 8).[13, 14]

- The ability of neighboring systems to supply emergency power may well diminish, as neighboring regions experience load growth that exceeds generation additions, and the reserve supplies in these regions decrease. The future ability to simultaneously import a total of 2,000 MW of uncontracted emergency assistance from Hydro-Québec, the Maritimes, and New York is uncertain. By 2008, New York is projected to run short of the installed capacity its criteria require. Ontario is also projected to be short of capacity resources within five years and will be facing additional governmental plans to phase out 6,500 MW of coal plants and acquire replacement resources within the same period. Since New England currently relies on 2,000 MW of tie benefits from other control areas, the projected resource adequacy of the surrounding NPCC systems is of great importance to New England. The projected capacity situation for the neighboring NPCC control areas coupled with transmission limitations shows that New England should not heavily rely on neighboring systems for capacity during periods of peak load, especially during the latter part of the planning period.

- While over 1,700 MW of New England generating capacity has been retired since 1999, RSP05 assumes no additional generators will retire during the 10-year planning period.

[12] Under OP 4 conditions, the system operator must take special steps to prevent curtailment of firm customer load. These actions include reducing operating reserves, reducing voltages, importing emergency power, activating emergency demand response to make capacity available, and taking other emergency measures while still maintaining transmission system reliability. See <http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html>.

[13] The first contingency is the loss of the first facility that has the largest impact on system reliability. The second contingency is the loss of the next facility, which would then have the largest impact on the system.

[14] For more information on OP 8, see <http://www.iso-ne.com/rules_proceds/operating/isone/op8/index.html>.

Operable Capacity Analysis

IC Requirement analyses do not identify the amount of resources that must be operational to meet a defined load level plus the requirements for operating reserves. Thus, to assess the ISO's operational risks and identify the amount of generating resources that must be operational to meet expected load and operating-reserve requirements, as well as the sensitivity of day-to-day system reliability and security to these risks at some point in the future, RSP05 complements the IC Requirement analysis with an operable capacity analysis. This is a deterministic analysis that reviews the ability of the bulk power system to serve load using a specific scenario. This approach compares the expected peak loads plus the requirements for reserve capacity to the amount of operable capacity the system is expected to have available during these peak loads. An adequate operable capacity margin maintains sufficient capacity resources to serve the native load and meet NERC and NPCC operating criteria (for operating reserves and transmission security) for the peak hour of each year, while recognizing the physical nature of the transmission system and the amount of capacity historically unavailable due to random forced outages on that peak day.[15] The operable capacity analysis considers both the 50/50 and 90/10 peak-load levels.

Fuel Diversity and Other Issues

RSP05 discusses the short- and long-term issues of fuel diversity. The short-term issues relate to a large portion of the gas-fired generating units lacking either firm gas contracts or dual-fuel capability to mitigate possible shortages of natural gas during periods of extreme winter weather. The longer-term issues relate to the ever-increasing reliance on natural gas in New England and neighboring regions and the need for more supply-side fuel diversity. The report discusses New England's winter capacity mix of fuels. It also summarizes a probabilistic study that investigated the physical risks related to winter gas-fired capacity and the amounts of dual-fuel conversions that could mitigate those risks. The report provides recommendations for encouraging dual-fuel capability and new energy resources.

RSP05 contains environmental information that can assist market participants in determining the types, amounts, and locations of resources they might find attractive for development. This includes analysis of future air emissions, the status of Renewable Portfolio Standards (RPS), and discussions of distributed resources including demand-response resources.[16] The report also presents the status of proposed generating projects in the ISO Interconnection Study Queue.

Transmission Studies

RSP05 summarizes the status of a number of transmission planning studies that aim to identify needed transmission facilities. Two studies that have a significant impact on RSP05 results have focused on reliability issues in southern New England and the interface constraints for the Connecticut and Southwest Connecticut imports.

[15] Additional information on NERC and NPCC planning criteria can be found at: <http://www.nerc.com/~filez/criteria-guides.html> and <http://www.npcc.org/criteria.asp>, respectively.

[16] State-mandated Renewable Portfolio Standards generally require competitive retail providers to supply a certain percentage of electricity from various renewable sources and technologies. Distributed resources are a growing form of smaller-sized on-site resources that involve load-reduction technologies or on-site generators. Distributed resources are typically located at or near load centers and are generally installed and owned by commercial or industrial facilities. A facility's use of these resources helps maintain the reliability of its electric supply during grid emergencies. Distributed resources may be installed to serve all or part of a facility's electric load and to provide thermal energy to enhance the economics of its overall energy supply. The ISO's demand-response programs are examples of distributed-resource measures. These programs provide financial incentives to customers that make their distributed-resource capacity available during OP 4 conditions or when wholesale prices are high. Demand response is when customers reduce load based on reliability needs or price signals.

Consistent with transmission reliability requirements, the ISO continues to study the southern New England region to identify and resolve its reliability issues. An overall goal of the study is to formulate a solution that better integrates load-serving and generating facilities within Massachusetts, Rhode Island, and Connecticut, thereby enhancing the grid's ability to move power between east and west and vice versa. The study report is scheduled to be completed by the end of 2005, and the project plan is scheduled for ISO approval by July 2006. The current in-service date for this project is December 2011.

The ISO has determined that the interface limits for the Connecticut and Southwest Connecticut imports have increased over the RTEP04 limits by 100 MW and 300 MW, respectively. This increase results from system improvements that relieved many voltage constraints in those areas. The new higher limits are primarily based on thermal limits, which will be addressed by subsequent projects. While operating practices have validated these study results, the ISO and the NEPOOL Reliability Committee will review the procedures and supporting documentation for establishing interface limits.[17]

RSP05 Findings

RSP05 generated data on future energy use and load growth, installed and operable capacity, and transmission needs. The results of the projected energy use and load-growth analyses conducted in January 2005 indicated that the use of energy in New England is projected to grow by 14% from 2005 to 2014. New Hampshire and Connecticut are projected to be the highest growth states. Greater efforts at conservation could reduce the energy-use growth rate throughout New England.

The summer 50/50 peak load in New England is expected to grow by about 15%, from 26,355 MW in 2005 to 30,180 MW in 2014. The summer 90/10 peak loads also are expected to grow about 15%, from 27,985 MW in 2005 to 32,050 MW in 2014. These projections include about 1,600 MW of peak reduction from ongoing utility-sponsored conservation programs. Due to several economic factors, the RSP05 summer-peak load forecasted for 2014 is about 1,000 MW higher than the RTEP04 peak load forecast for 2013. The preliminary peak load of July 19, 2005, was 26,749 MW, establishing a new all-time system peak for New England 5.5% higher than the previous all-time peak established in 2002. Eight days later on July 27, the system reached another all-time peak of 26,921 MW. This peak load would have been even higher by approximately 200 MW had demand-response measures not been activated in Connecticut under OP 4.

The long-run peak load forecasts in RSP05 assumed a constant load factor, which has been found to be inconsistent with historical data and short-term forecasts and has contributed to the under-forecasting of summer-peak loads. The ISO is in the process of improving its peak-forecast methodology by extending its declining summer-peak load factor over the entire forecast period.

Table ES.1 shows projected resource needs in New England in terms of the amount and types of generating resources needed and where and when these resources will be needed. The table also relates the system needs identified in RSP05 to solutions and requirements. The following sections summarize the findings presented in the table.

[17] For information on the NEPOOL Reliability Committee, see <http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/index.html>.

TABLE ES.1

Summary of RSP05 System Needs, Solutions, and Requirements Based on RSP05 Assumptions and Analyses

System Needs	Solutions	Specific Requirements
Meet load-pocket requirements	Add resources to satisfy reliability needs (preferably quick-start resources)	For Greater Connecticut: Operable Capacity: - Need 30 MW by 2006 (90/10 load) - Need 670 MW by 2009 (90/10 load)
Meet systemwide operable capacity forecast requirements	Meet systemwide needs by adding quick-start resources that satisfy load-pocket needs	- Need 160 MW by 2008 (50/50 load) - Need 1,900 MW by 2008 (90/10 load)
Provide operating reserves	Add incremental quick-start resources or units with energy prices competitive with resources external to the load pockets	For Greater Connecticut: - Need 530 MW by 2006 *The preferred location for adding quick-start resources for meeting the needs of Greater Connecticut is Greater SWCT because this area needs 350 MW by 2009* - Need 500 MW in BOSTON by 2006
Meet systemwide 1-day-in-10-year LOLE criterion	Meet systemwide needs by meeting load-pocket needs	- Need 170 MW systemwide by 2010
Reliably operate system when gas is not available	Achieve greater fuel diversity by adding incremental dual-fuel conversions in southern New England, predominantly BOSTON	- Need 400 MW by winter 2006/2007 - Need an additional 250 MW every winter through 2008/2009 - Need an additional 500 MW in winter 2009/2010

Need for Capacity and Operating Reserves in Load Pockets

Among specific subregions, Greater Connecticut has the most significant resource need in New England, coupled with transmission constraints that limit the import of electricity into the state. If additional resources are not added soon, or the transmission lines currently being developed are not completed in a timely manner, these constraints create a significant risk that system operations will be required to shed load or to disconnect firm customers during periods of extremely hot weather and when generating units are less available than expected.

RSP05 results indicate that Greater Connecticut is also short of quick-start generating capacity that provides economical operating-reserve coverage under high-load conditions. Because of this shortage, intermediate units not economic in the energy market must be put on-line (for which the load-serving entities would incur operating-reserve costs) to provide the 30-minute response needed to maintain reliability upon loss of a critical generator or transmission line.[18]

Greater Connecticut currently needs an additional 530 MW of resources that can provide 30-minute response to meet its operating-reserve and second-contingency coverage. Ideally, a majority of these quick-start resources

[18] Operating-reserve costs are payments to generators for operating when it is more expensive for them to do so than the price-setting generator in the energy markets.

would locate in Greater Southwest Connecticut, which would need approximately 350 MW of this type of resource. These resources are needed with the addition of Phase 2 of the Southwest Connecticut Reliability Project, due to be in service in late 2009 and required to reliably serve load in Greater Southwest Connecticut.

BOSTON, another subarea of New England's power system, needs 500 MW of quick-start resources now to reduce out-of-merit commitment of uneconomic generation and provide operating reserves for contingency coverage under high-load conditions. Adding quick-start resources in BOSTON also would serve New England's overall resource adequacy needs and help reduce some of the operating-reserve costs in Boston. Adding quick-start units in the southern part of the New England system would provide for operating flexibility and improve the reliability of operation at critical load centers. As noted below, it is desirable for the units to have dual-fuel capability.

Systemwide Capacity Needs

By 2010, New England will require about 170 MW of capacity to meet the NPCC and ISO New England 1-day-in-10-year LOLE criterion. This calculation assumes no additional units will retire or deactivate by 2010 and load-growth and other assumptions remain appropriate. These results indicate total resource capacity barely meets the reliability requirement today and, as load grows, the need for operation under OP 4 will become more commonplace during high-demand hours.

During times of extreme peak demand, the use of additional capacity over the amount committed to firm contracts or OP 4 actions during emergency conditions may be needed. The fragile state of the transmission system and the lack of sufficient 30-minute-response resources in Connecticut make it especially vulnerable to the risk of unreliable operation or, in extreme conditions, load shedding. Quick-start resources and added diversity in generating-unit types are needed to reduce the operational risks identified.

Based on the results of the operable capacity analysis, by 2008, New England must acquire or rely on OP 4 actions to gain an additional 160 MW and 1,900 MW to meet the 50/50 and 90/10 peak-load forecasts, respectively.

Taken together, the results of the installed and operable capacity analyses demonstrate that New England will likely face an increased risk of operating with less capacity than needed by 2008. The results also show that the region will not have sufficient capacity to meet the IC Requirement in the 2008 to 2010 timeframe, depending on load growth, weather conditions, generator performance and attrition, and the conditions in specific load pockets, such as Connecticut. Because the timeframe for building new generation resources is about two to four years, the analysis highlights the urgent need for new generating resources in New England.

Need for Fuel Diversity

ISO's operating experience and RSP05 highlight a high level of vulnerability to increases in gas and oil prices and the potential for fuel disruptions in that gas and oil fuel plants provide almost two-thirds of the system's capacity. RSP05 identifies that to mitigate the impacts of possible natural gas shortages on system reliability during the winter, the region must convert approximately 400 MW of gas-fired generation to dual-fuel capability by winter 2006/2007, increasing the amount by 250 MW per year through 2008/2009 and by 500 MW for 2009/2010. Alternatively, gas-fired units could contract for firm supply, recognizing that scheduling flexibility may not be available for quick-start units. Study results indicate that converting gas-fired generation in southern New England, particularly in the BOSTON Subarea, to dual-fuel operation would help mitigate reliability concerns. These concerns are associated with a natural gas shortage that could occur during a winter cold snap and a resulting regional gas shortage. Additional dual-fuel capability, an additional firming of contracts, and/or an increase in the natural gas delivery system infrastructure-including new liquid natural gas (LNG) terminals-will be needed to support load growth in the future if gas continues to be a preferred fuel for new generation.

Since approximately 50% of New England's generating capacity is capable of being fueled with natural gas, and gas actually fuels 40% of the region's electrical energy generation, the region must focus on developing greater fuel diversity for its electricity supply for the long term. The fuel-diversity analysis clarified that adding resources, including nuclear-powered capacity, coal units, or renewable resources, will improve reliability in New England. RSP05 determined that energy conservation and peak-load management programs could contribute to decreasing New England's need for capacity in the short term and improve the fuel-diversity situation. The region also has the increased potential for using distributed resources to meet New England's growing demand for electricity.

An increasing energy use and rising natural gas prices relative to oil prices will tend to increase generating plant production by oil units, resulting in higher total air emissions in New England over the 10-year period. Conservation efforts and renewable resources will reduce emissions and encourage greater fuel diversity.

Needed Transmission Projects

RSP05 identifies 272 transmission projects required throughout New England to meet planning criteria. These upgrades are required to reliably serve load and to reduce the need to commit generating units for operating reserves, voltage support, and relief of other transmission constraints. These 272 projects are estimated to cost about $3.0 billion. Two-thirds of this cost is related to the following six major 345 kV projects.

- NSTAR 345 kV Reliability Project
- Southwest Connecticut Reliability Project Phase 1
- Northwest Vermont Reliability Project
- Northeast Reliability Interconnect (NRI) Project
- Southwest Connecticut Reliability Project Phase 2
- Southern New England Reinforcement Project

The load/generation pockets discussed in RSP05 include Middletown (CT); Norwalk-Stamford (CT); Southwest Connecticut; Springfield (MA); Boston; Wachusetts (MA); and the North Shore (MA). Additional studies are required to finalize many of the 272 projects, such as those required for increasing the northern New England transmission-transfer capability and improving the voltage performance of Downtown Boston.

Most of the transmission projects identified during the RSP process are reliability upgrades for ensuring the region continues to satisfy national and regional reliability standards while continuing to operate in an economical manner. Many of these upgrades will provide the additional benefit of enhancing the efficient operation of the region's power markets, as they will allow access to generating resources external to the load pockets, the repowering or interconnection of generating facilities, and the movement of power to where it is needed.

Infrastructure Achievements

This is the fifth year of ISO's leadership on the RTEP/RSP process for the region, and much progress has been made over the past years in planned transmission projects and market enhancements. Since the inception of the RTEP/RSP planning process in 2001, significant system improvements and modifications have been identified, seventy-five projects have been placed in service totaling $217 million in construction costs, and many others are well on their way toward completion. As of September 2005, the ISO had close to 500 MW enrolled in all of its demand-response programs implemented as part of Standard Market Design (SMD).[19] An audit in August 2004 of the demand-response programs showed these resources to be substantially capable when called upon to reduce load.

Transmission Upgrades

Because Connecticut and Southwest Connecticut are considered critical areas in terms of service reliability, shorter-term system improvements have been implemented in these areas. Coupled with reactive improvements to the distribution system, several completed reliability projects in Connecticut have enhanced both system reliability and market efficiency. Highlights of these projects are as follows:

- Elimination of a Long Mountain stuck-breaker contingency that led to the loss of three 345 kV lines
- Installation of the Glenbrook static compensator (STATCOM) to improve voltage performance in Southwest Connecticut
- Installation of two dynamic Voltage Ampere Reactive (DVAR) systems to improve voltage performance in Southwest Connecticut
- Installation of capacitor banks at strategic locations in Connecticut to further support steady-state voltage conditions
- Replacement of circuit breakers across Connecticut to increase short-circuit interrupt duty

ISO studies show that these improvements have reinforced the reliability of the Connecticut transmission system in advance of completing the major 345 kV reinforcement projects taking place in New England (see below). Earlier improvements have increased transfer limits into Southwest Connecticut by 300 MW, from 1,700 MW to 2,000 MW. More recent transfer-limit improvements have increased transfer limits into Southwest Connecticut by another 300 MW (up to 2,300 MW) and Connecticut's ability to import power by 100 MW up to 2,300 MW. These improvements help bring lower-cost energy into each area when available and mitigate the need for out-of-merit commitments for system reliability support. However, these projects have not eliminated the need for major additional system improvements.

Similarly, the NEMA upgrades, placed in service in the 2002 to 2003 timeframe, improved reliability to the northeastern Massachusetts/Boston load pocket while increasing transfer limits by 300 MW. The recent installation of a reactor in Cambridge helps improve VAR control in the Cambridge/Boston area during periods of lighter load. Significant progress has been made over the past year in siting and constructing five of the six major 345 kV projects the RTEP/RSP process has identified as critical for supporting a reliable power supply in New England into the foreseeable future, as summarized below:

- **NSTAR 345 kV Reliability Project**—increases the transfer limits into the Greater Boston area. The Massachusetts Energy Facilities Siting Board permitted the project in January 2005, and NSTAR has commenced construction. The projected in-service date is June 2006 for the first two cable circuits.

[19] ISO New England implemented Standard Market Design on March 1, 2003. SMD is an energy market structure that incorporates locational-marginal pricing, day-ahead and real-time energy markets, and risk-management tools to hedge against the adverse impacts of having to pay higher locational-marginal prices (LMPs) when transmission congestion occurs.

The third cable is scheduled for service before summer 2008. The first two cables will increase the import capability by 900 MW and the third cable by another 200 MW.

- **Northeast Reliability Interconnect Project**—adds a new 345 kV tie line between New England and New Brunswick to improve the transfer capability between the two regions by 300 MW and improve system performance in northern Maine. The Maine Public Utilities Commission permitted the project in July 2005. The projected in-service date for this project is December 2007.

- **Southwest Connecticut Reliability Project Phase 1**—improves the transfer of power and system performance in Southwest Connecticut as the first stage of the major Northeast Utilities/United Illuminating Company (NU/UI) 345 kV project. The project is currently under construction with a projected in-service date of December 2006. Phase 1 will increase the import capability by 275 MW.

- **Southwest Connecticut Reliability Project Phase 2**—improves the transfer of power and system performance in Southwest Connecticut as the second stage of the major NU/UI 345 kV project. The Connecticut Siting Council (CSC) permitted the project in April 2005, and the project is currently in the final design and analysis stage. Its projected in-service date is December 2009. Phase 2 will increase the import capability by 825 MW.

- **Northwest Vermont Reliability Project**—improves the Vermont Electric Power Company's (VELCO) 345 kV and 115 kV transmission system for the major load center in northwestern Vermont. The Vermont Public Service Board permitted the project in January 2005 and, as part of that approval, ordered several project modifications. VELCO has commenced construction, is preparing the final design, and is analyzing project modifications. The projected in-service dates for individual stages of the project range from May 2006 through October 2007.

In addition to the Connecticut, NEMA/Boston, and major 345 kV line projects, a number of other significant system improvements are being made. The North Shore/Ward Hill (MA) Substation is currently being upgraded to work in conjunction with the NSTAR 345 kV project. Two of three 115 kV line upgrades from Ward Hill Substation have been completed, and an autotransformer is being added. Other improvements were made to increase the reliability to the Cape Cod load pocket, including the addition of an autotransformer, a new line, and a capacitor bank. The Central Massachusetts Project, which will unload the Sandy Pond Substation transformers, and the Auburn Project, which will upgrade a number of stations and lines in the Auburn-DuPont-Bridgewater area, also are under construction.

To increase the SEMA/RI export capability, improvements were made to select breakers at West Walpole, West Medway, Millbury, and Sherman Road. To increase the ability to move power within the Norwalk-Stamford and SWCT load pockets, two lines from Glenbrook Substation were reconductored, and 115 kV cables in the Bridgeport area and the Baird-Congress 115 kV lines were upgraded. Autotransformers were added at Scobie Substation in New Hampshire and at West Rutland Substation in Vermont.

Other projects nearing construction or recently begun include the following:

- **Southwest Rhode Island**—will increase both reliability and inter-area transfer capability between Rhode Island and Connecticut.

- **Y-138**—will increase both reliability and increase the transfer capability between Maine and New Hampshire by 100 MW.

- **Monadnock**—will eliminate thermal and voltage problems and increase reliability by creating stronger ties between central Massachusetts, southeastern Vermont, and southwestern New Hampshire.
- **Vermont Northern Loop**—will increase the reliability of the line by looping it through the area instead of feeding it radially.
- **Haddam Substation**—will connect a 345/115 kV autotransformer into the 115 kV system in south-central Connecticut.
- **Killingly Substation**—will install a 345/115 kV autotransformer in Connecticut into a 115 kV system, increasing the transfer limit into Connecticut.

New Initiatives

RSP05 identifies several new ISO initiatives and tasks to improve its planning process and assure the future reliability of service to the region's load:

- Develop a *Horizon Year Study* to provide longer-term direction for New England's transmission development.
- Review the load-forecast methodology to improve its quality.
- Conduct a comprehensive review of all the methodologies, criteria, and assumptions used to calculate the Installed Capacity Requirements for the system and load pockets. The review will take about 18 months to complete, with any revisions incorporated in the calculation used to generate the IC Requirements for Power Year 2007–2008.
- Initiate a long-term program to improve the monitoring and control of the grid. This effort will assess the data-communication and substation monitoring and control equipment presently installed on the grid and the effectiveness of the methods and facilities system operators use to respond to contingencies, including load shedding.
- Identify and address those issues that obstruct the market from providing, in response to price signals, the resources needed to reliably operate the power grid. These measures will reduce the commitments made to generating resources operating out of economic merit order to satisfy power system criteria. One area of focus for this project will be to identify key upgrades to the power system infrastructure that would reduce or eliminate the need to commit out-of-market generation to control voltage.
- Investigate the pricing rules and operating procedures to ensure that they are consistent with each other and that barriers do not exist for properly pricing or efficiently using resources.
- Evaluate and apply advanced technology solutions to maximize the thermal use of existing rights-of-way and improve voltage performance. These solutions include the use of new conductor technologies and innovative voltage-control devices.
- Conduct interregional transmission planning. Implementation of the Northeast Planning Protocol and continued participation in NPCC activities will improve coordination with neighboring control areas.

- Review the long-term viability of each Special Protective Scheme (SPS) used on the New England bulk power system to optimize transfer capability.

Recommendations for New England

The following are the ISO's recommendations to assure, through market incentives where appropriate, a reliable and more robust electricity supply system is implemented in New England over the next 10 years:

- **Complete Transmission Projects**—Improve the New England infrastructure and maintain power system reliability in New England over the next 10 years by supporting the timely completion of ongoing transmission improvements identified in RSP05. The report currently contains 272 projects, which will continue to be modified on an ongoing basis as new improvements are identified and projects are completed or eliminated from the listing.

- **Develop Resources**—Increase systemwide resources by at least 160 MW in the 2008 to 2010 timeframe. Add 670 MW in the Greater Connecticut load pocket by 2009 to satisfy reliability needs. Increase quick-start resources by 530 MW in Greater Connecticut now and by 500 MW in BOSTON to improve operating flexibility and efficiency. Greater Southwest Connecticut also needs 350 MW of quick-start resources by 2009, but if added by 2006, it can help satisfy Greater Connecticut's reliability needs. These needs are not mutually exclusive. The addition of quick-start resources in Greater Connecticut or BOSTON will satisfy system requirements. Additions to quick-start resources in Greater Connecticut will satisfy load-pocket needs as well as system needs.

- **Enhance Fuel Diversity**—Develop mechanisms to attract an improved diversity of fuel types for the New England fleet of supply resources. This should include clean coal technologies and additional nuclear resources. In addition, investigate the impact that alternative resources, such as wind and distributed generation (DG), will have on the operation and long-term security of the power system.

- **Improve Firmness or Flexibility of Gas Resources**—Firm up gas-supply arrangements for at least 400 MW or convert 400 MW to dual-fuel operations in southern New England by 2006 to 2007. This will provide for reliable operation of the system during periods of high demand when natural gas may be unavailable for electricity generation. Increase the arrangements or conversions by 250 MW per year through 2008/2009 and by another 500 MW by 2009/2010.

- **Develop Gas Supplies**—Develop new gas supplies and delivery capacity, including LNG facilities, to meet increased demand in New England.

- **Increase Demand Response**—Increase the penetration of demand response as part of the overall supply to assure reliability and ensure its operability.

- **Improve Operational Control**—Initiate a long-term program to improve the monitoring and control of the grid, to prepare for the upcoming period in New England when capacity will become more constrained and to respond to recommendations of the August 2003 Blackout Task Force.[20] This will allow the ISO and the local control centers to better monitor the grid and more accurately initiate load shedding at a substation feeder level.

[20] Natural Resources Canada and U.S. Department of Energy, *The August 14 2003 Blackout One Year Later: Actions Taken in the United States and Canada to Reduce Blackout Risk*. Report to the U.S.-Canada Power System Outage Task Force. August 13, 2004.

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