First Draft

New England Electricity Scenario Analysis:

Exploring the economic, reliability, and environmental impacts of various resource options for meeting the region's future electricity needs

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Executive Summary

New England's public officials and other stakeholders face a number of issues regarding the future path for the region's electric power system. In the past decade, New England has seen substantial investment in new power production facilities—all of it coming in response to market and policy signals in the region. Almost all these new power plants, planned and built when natural gas prices were forecast to remain relatively low, operate on gas as the primary fuel. While the newer plants are much more efficient and have lower emissions than the older plants, natural gas prices have nonetheless doubled since 2000, resulting in electric energy price spikes and concerns about fuel diversity and overall system reliability.

This situation is challenging for a number of reasons. Residents and businesses expect reliable power on demand. And they want it to be low cost. But New England has long been a region with high energy costs and some of the highest retail electricity prices in the nation, and policymakers are searching for ways to lower electricity bills. At the same time, policymakers and citizens alike want the power sector to continue to make environmental progress, as witnessed by some New England states adopting air emission regulations stricter than required by the U.S. Environmental Agency (EPA) to limit sulfur dioxide (SO_2) and nitrogen oxide (NO_X)—which contribute to the formation of acid rain and smog, respectively—and carbon dioxide (CO_2), which has been linked to climate change. New England policymakers also want the region's electricity consumers to pursue energy efficiency on a more aggressive schedule than in the recent past. And, for reliability reasons, system planners have identified the need to diversify the types of fuels used to generate electricity and decrease the region's dependence on natural gas.[1]

Simultaneously accomplishing these three economic, reliability, and environmental objectives is highly complex. Given the region's lack of indigenous fuel supplies, dependency on imported fossil fuels, and its tightening environmental policies, it will be difficult to substantially reduce electricity costs. The challenge for policymakers is to find an appropriate balance between economic and environmental goals while ensuring reliability.

In theory, many options are available to satisfy New England's incremental electricity needs. Among them are ways to reduce demand, such as by increasing the use of more efficient appliances and equipment or by installing devices to cycle electric appliances on and off during peak hours. On the supply side, new transmission lines to allow more power to be imported can be built, and renewable resources, such as wind farms and solar photovoltaic (PV) projects, new gas-fired power plants (despite fuel-diversity issues), and even new coal or nuclear power plants, to name a few, can be

[1] *2006 Regional System Plan* (hereafter cited as RSP06) (Holyoke: IS0 New England Inc.; October 26, 2006) Section 6, and *2005 Regional System Plan* (hereafter cited as RSP05) (Holyoke: ISO New England Inc.; October 20, 2005) Section 5. Available online at http://www.iso-ne.com/trans/rsp/2006/rsp06_final_public.pdf and http://www.iso-ne.com/trans/rsp/2005/05rsp.pdf, respectively or by contacting ISO Customer Service at 413-540-4220.

added. These options tend to involve different trade-offs of one form or another. For example, while some of the technologies may come about naturally as a result of market forces, others may require change in public policy to encourage their development.

To help clarify some of these trade-offs and to inform the public, regional policymakers, and other decision makers about various choices for meeting consumers' electricity needs, the ISO has sponsored a regionwide initiative, the New England Electricity Scenario Analysis. The ISO's intention for this initiative was to provide a venue to examine how various ways of supplying electricity to the region could affect the costs to provide power, system reliability, and the environment. With this initiative, the ISO aimed to generate meaningful data, information, and discussion that regional decision makers can use as they develop New England's electricity markets and policies.

Over the past eight months, the ISO has worked with a Steering Committee, a number of focused working groups, and a plenary group comprising representatives from the ISO, utility and environmental regulators from the New England states, market participants, environmental and efficiency advocates, and other interested stakeholders. Together, these participants have identified and analyzed a number of supply- and demand-side resource scenarios, each revolving around a particular technology path.

The scenarios selected for analysis did not attempt to identify "right" or "wrong" electric technologies or develop a plan for what the region *should* or *will* do; none of the scenarios is designed to predict what the future will look like in New England or to dictate a particular path. Nor did the ISO attempt to build consensus about "preferable" technologies or outcomes. Additionally, this analysis is not a least-cost plan or multi-year present-worth analysis. Rather, the scenarios explore a comparable set of diverse economic, reliability, and environmental impacts, outcomes, and directions that might reasonably be expected to occur *if* one electric technology path were pursued over another.

The Seven Scenarios

Seven basic scenarios or technology paths were selected for analysis:

- **Scenario #1—The "Queue" Mix,** reflecting a combination of power plant technologies that were proposed in New England as of September 30, 2006, notably including gas-fired "peaking" units, combustion turbine (CT) units, and renewable resources[2,3]

- **Scenario #2—Demand-Side Resources,** including energy-efficiency technologies that reduce electricity use for a given level of system load or shift usage from on-peak to off-peak hours or reduce it during regionally high peak-demand conditions[4]

[2] The date of September 30, 2006, coincides with the start of the Scenario Analysis initiative.

[3] Relative to other types of resources, a *peaking un*it is designed to start up quickly on demand and operate for only a few hours during system peak days, which amounts to a few hundred hours per year. A combustion turbine is an example of a peaking turbine.

[4] Demand- and price-response measures are two types of demand-side resources. *Demand response* is when a demand-side resource reduces its consumption of electricity in response to a system reliability event and in exchange for compensation based on wholesale electricity prices. *Price response* is the reduction of electricity consumption in response to a price signal in exchange for compensation based on wholesale electricity prices.

- **Scenario #3—Expansion of Nuclear Capacity,** assumed to occur at or near existing nuclear stations in New England

- **Scenario #4—New Coal-Fired Power Plants Using Integrated Gasification Combined-Cycle (IGCC) Technology**, which gasifies coal and then runs the gas stream through a combined-cycle power production facility

- **Scenario #5—New Natural-Gas-Fired Combined-Cycle (NGCC) Power Plants,** reflecting additional new power plants similar to those added in large numbers in the region over the past decade

- **Scenario #6—New Renewable Projects,** reflecting a combination of new renewable technologies, including offshore wind, inland onshore wind, hydroelectric power, biomass, fuel cells, landfill gas (LFG), combined heat and power (CHP) systems, and solar photovoltaic (PV) technologies

- **Scenario #7—Increased Imports of Hydroelectric Power and Other Low-Emission Resources,** reflecting new transmission investment to support imports of a significant amount of new power supply from both Canada and New York

Assumptions and Methodology

The analysis envisioned a system demand of about 35,000 megawatts (MW) in the timeframe of beyond 2020 to 2025. The timeframe was far enough into the future to avoid knowing exactly when this level of demand would be reached.

In addition to the demand level, the analysis used a number of common assumptions about certain elements of the future state of the electric system—the resource mix, future fuel prices, operational characteristics of the region's existing fleet of power plants, incremental transmission costs that might be required for certain scenarios, and rates of and allowance costs for various air emissions. To see how sensitive the results were to changes in a number of key variables, the ISO modeled cases using alternative assumptions for fossil fuel prices (a low-price case and a case with significantly high natural gas prices), carbon-related emission allowance prices (a high- and low-price case), the type and degree of penetration of demand-side resources, the retirement of the oldest power plants in the region, and several other variables.

Accounting for these assumptions and the system's existing generation and transmission facilities, the ISO modeled how various combinations of resources within each scenario could perform in supplying customers' electricity needs. The simulations reviewed system performance in all hours of the future "study year." Although limited in scope, the analysis ran a total of 52 simulations using these different metrics.

For each scenario and the sensitivity analyses accompanying them, these results included systemwide economic, reliability, and environmental metrics. Economic metrics included the following:

- Average and total systemwide costs to produce power

- Overall efficiency with which power is produced

- Average clearing prices in electric energy markets
- Ranges of capital costs associated with each technology

The analysis also evaluated the ability of projected market-based net energy revenues to support these investment costs (including incremental investment in electric transmission and fuel-supply delivery infrastructure costs). This suggests the extent to which investing in a particular technology might be supported by revenues in the wholesale energy markets alone and the requirement for revenues from other sources, such as tax incentives, absent any changes in policy or other revenue streams.

Examples of reliability metrics include the amount of electricity produced by different types of power plants, total fuel consumed to produce power (by type of fuel), and exposure of the electric power system to various types of fuel-related shortages.

The environmental outcomes that were tracked include such metrics as systemwide emissions of SO_2, NO_X, and CO_2, as well as the 10 highest daily NO_X emissions for peak-load summer days. The use of water for cooling new power plants, the incremental amount of land needed to produce and transmit power, and the percentage of power produced by renewable resources were also evaluated.

Key Themes of the Results and Conclusions

The numerous results of the Scenario Analysis provide a picture of how the electric power system's reliability, economic, and environmental impacts could vary given changes in the technology path. Some of the key themes that have emerged are as follows:

- ***Under all the scenarios, New England will continue to depend on natural gas to supply electricity.*** Even adding 5,400 megawatts (MW) of new capacity from a single technology or resource type (i.e., nuclear, renewables, imports, or energy efficiency), will not change this dependence. Mainly as a result of adding a large amount of new gas-fired generating capacity to New England over the past decade, these plants would continue to have output levels shaped by changing fuel prices. In all scenarios, natural gas would comprise a minimum of 36% of the systemwide capacity. This is because, in large part, each of the cases assumed that 8,000 MW of new capacity was added to a generating capacity base of approximately 31,000 MW existing in 2007. The biggest changes in the capacity mix occur in the sensitivity cases that assumed that 3,500 MW of the oldest generating capacity in the region would be retired and replaced with capacity provided by that scenario's core technology. The addition of 8,900 MW of NGCC generating units would grow this percentage to 58%.

- ***The prices of fossil fuels, particularly natural gas, drive the region's electric energy mix, costs, electric energy prices, and level of emissions.*** Low natural gas prices relative to expected crude oil prices reduce electric energy prices and lower air emissions. High natural gas prices tend to increase the price of electric energy and increase the overall emissions of SO_2, NO_X, and CO_2. If gas shortages were to occur, the system would be exposed to fuel interruptions and increased commodity prices, which would in turn expose New England to greater electric energy price volatility.

  However, predicting future oil and gas prices and circumstances is difficult, if not impossible, and the underlying forces in global energy markets could lead to a wide variability of results for the scenarios and cases analyzed. The addition of infrastructure in the regional natural gas supply and delivery systems and reductions in gas sector demands could mitigate price volatility during periods of high demand. Several demand-side technologies [e.g. efficient gas-fired heating systems; additional home insulation; heating, ventilation, and air-conditioning (HVAC) environmental controls] could provide the dual benefits of reducing the demand for both natural gas and electrical energy, at the same time reducing prices for both products.

- ***Across all the scenarios and sensitivity cases, gas-fired power plants tend to be among the last plants dispatched (the so-called marginal units) in New England to meet demand and the plants that set electric energy clearing prices in the wholesale electricity markets in most hours of the year, approximately 90% of the time.*** Therefore, average clearing prices appear to be most sensitive to the price of natural gas, and the overall average clearing prices differ only somewhat across the scenarios. However, some scenarios (e.g., nuclear, natural gas combined cycle, renewables) and a double-energy-efficiency sensitivity case result in more efficient natural gas units being on the margin and subsequently having average clearing prices that are lower by up to 10% than several other cases.

- ***The scenarios that have low variable cost, low emissions, and medium-to-high energy output (e.g., double energy efficiency, nuclear, hydro imports) will produce electricity more efficiently (i.e., with less overall fossil fuel consumption and lower emissions).*** Just as the overall efficiency of the region's power system has improved in the past decade—as newer, more efficient power plants with lower air emissions have been added—the scenarios show continued improvements in the overall systemwide efficiency of converting fossil fuels to electrical energy. The scenario cases that assume the retirement of the region's oldest generating capacity underscore this result, producing results that indicate fewer overall emissions of NO_X, SO_2, and CO_2; lower production costs; and less oil consumption.

- ***New England's CO_2 emissions from the power sector vary considerably across the scenarios.*** The analyses indicate that for the different cases, satisfying the region's CO_2 emissions targets under the Regional Greenhouse Gas Initiative (RGGI) will require some combination of adding substantial amounts of low- or zero-CO_2-emitting resources or having affected power generators buy additional CO_2 allowances from sources outside the region.[5] If New England were to reduce CO_2 emissions by adding more renewables in areas far from load centers or importing more hydroelectric power, the region will need to build substantially more transmission to move this power to the load centers.

- ***The demand-side resources provide capacity and energy to the system at relatively low capital costs and emissions.*** Similar to other low- or zero-emitting supply-side technologies, energy efficiency provides capacity, electric energy "savings," and emission benefits to the system. Because the demand-response resources have operating characteristics that are similar to peaking units, the Scenario Analysis shows that these resources provide capacity but relatively little electric energy to the system. Other demand resources, such as energy efficiency, have operating characteristics that are similar to baseload units and provide capacity and energy savings.

[5] The Regional Greenhouse Gas Initiative is a 10-state voluntary CO_2 cap-and-trade program being implemented in the Northeast. Under RGGI, the Northeast region will cap its emissions at 1990 levels by 2014 and reduce this level by 10% by 2018. The six New England states will be allocated 50.2 million tons of carbon allowances and will either need to reduce emissions to that level or trade emissions allowances with other states in the Northeast region (which includes New York, New Jersey, Maryland, and Delaware).

The Scenario Analysis has produced volumes of detailed information about the scenarios—the economic, reliability, and environmental impacts of the expansion technologies on the region's future electric power system and how these impacts change under different sets of assumptions. This summary provides only the tip of "information iceberg." Additional results are summarized in this report; all the results are available to the public on ISO's Web site.

To assist stakeholders in analyzing the data, the ISO is also posting on its Web site a spreadsheet tool that stakeholders can use to explore the information, make their own investigations, and even assess the impacts of making different assumptions (i.e., about capital costs, transmission requirements, gas delivery infrastructure costs, and the like). The ISO encourages interested parties to compare the results for the different scenarios and reach their own conclusions about the various options.

Consistent with the original objectives of this initiative, the Scenario Analysis stops short of indicating what steps the region should now carry out. The ISO is willing to continue to work with policymakers and stakeholders to define the next stage in this analysis.

Section 1 Introduction

New England's electricity infrastructure and marketplace provides the region's 14 million people with a reliable supply of electricity. Over the past decade, substantial investment in the region's electric power system has added much new generating and transmission capacity, demand-side measures, distribution system enhancements, and other upgrades to help assure that the system continuously operates even during unexpected infrastructure outages.[6,7]

Virtually all the new power plants added in the region since 2000 burn natural gas as their primary fuel, and were planned and built when gas prices were forecast to remain relatively low. Since 2000, however, natural gas prices have doubled and are subject to considerable volatility, which has led to relatively high electricity prices for New England's consumers. In addition to this price volatility, the region's reliance on significant amounts of natural gas makes New England more vulnerable to short-term seasonal reliability issues.[8] On top of the need for enhanced fuel-supply diversity is the need to add more capacity in the long term, as indicated by the long-range capacity and resource adequacy forecasts conducted as part of the ISO's regional system planning process.[9] In planning for possible fuel-diverse capacity, the region must comply with regulations at all levels that aim to protect the region's environment—air, land, and water.

Most would agree that New England's future economic health depends on the region having a reliable, low-cost, and environmentally sound supply of electricity that can minimize variations in costs that result from dramatic changes in fuel prices or fuel availability. Moreover, an increase in demand-side resources is key to providing an economically efficient mix of systemwide resources that decreases the need to build new facilities, eases the burden on existing infrastructure and land and water resources, and lowers the power plant emissions of the sulfur dioxide (SO_2), nitrogen oxides (NO_X), and carbon dioxide (CO_2) gases that contribute to acid rain, the formation of ozone (smog), and greenhouse gases, respectively. Many options exist to accomplish these hoped-for objectives, supply-side and demand-side. Among the well-known demand-side resources available in the near term are the following:

- Using energy-efficient lightbulbs, refrigerators, air conditioners, and other equipment and adopting other advanced energy-efficiency measures in homes, offices, appliances, and industrial processes[10]

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[6] Between 2000 and 2004, private companies have invested more than $6 billion in new, modern power plant capacity, adding 9,000 MW of supply. The ISO's demand-response programs have grown from approximately 100 MW in early 1997 to more than 900 MW enrolled in early 2007. Also since 2000, New England's transmission companies have put into service close to 200 transmission system enhancements for reliability purposes. By the end of 2007, this will represent an investment of approximately $1.5 billion.

[7] In general, *demand-side* resources are measures that reduce the use of electricity from the bulk power system in homes, offices, industries, and for other uses.

[8] *2006 Regional System Plan* (hereafter cited as RSP06) (Holyoke: IS0 New England Inc.; October 26, 2006) Section 6. RSP06 is the ISO's the most recent annual planning report that contains information about the resources and transmission facilities needed to maintain reliable and economic operation of New England's bulk electric power system over a 10-year horizon. (Available online at http://www.iso-ne.com/trans/rsp/index.html.)

[9] RSP06 Section 4.

[10] Energy efficiency measures reduce the energy inputs for a given level of service or increase or enhance services for a given amount of energy inputs. Additional information is available online at http://eia.doe.gov/emeu/efficiency/definition.htm.

- Incorporating energy-efficiency-related elements into the building codes for homes and offices so that new structures must use equipment and processes that are more energy efficient than standard ones
- Shifting the use of appliances (e.g., dishwashers and washing machines) from on-peak (summer afternoon) to off-peak (summer morning or evening) periods
- Using advanced meters and software that show generally transparent real-time price signals to consumers as an incentive to modify their use of electricity as the cost to supply it changes over the course of the day (called *price response*)—for example, when consumers switch to using small-scale on-site "distributed" generation (DG)
- Using automatic devices to cycle equipment on and off during on-peak hours (e.g., briefly turning off air conditioners during those same summer-peak hours), called *demand response*

Available supply-side options include the following measures:

- Adding wind, solar, and other renewable resources
- Upgrading long-distance transmission systems to provide greater imports of power supplies from outside the region
- Building new gas-fired and coal power plants and expanding generating capacity at nuclear stations

These options involve a range of different trade-offs—different technological paths, combinations of supply-side and demand-side resources, decisions about energy supply and use, local and regional environmental outcomes, time horizons and investment pay-back periods, investment options and approaches, costs, reliance on fuel sources from outside the region, risks and uncertainties, and so forth. Some of these trade-offs are well-known; others are less obvious or easily understood.

1.1 Purpose of the Initiative

Recognizing that the region must pursue new energy resources in the near future and to help clarify some of the trade-offs involved in pursuing the various paths to attain these resources, the ISO has initiated a Scenario Analysis study. This initiative has sought to inform regional policymakers and stakeholders about various choices for meeting consumers' needs for reliable, economically efficient, and environmentally sound supplies of electricity. By presenting a series of economic, reliability, and environmental results—for such metrics as the cost to produce electricity, electricity prices, electric power supply reliability, fuel diversity, total emissions, and other dimensions of interest—this exercise sheds light on each technology path's implications for the region and future investment in electricity resources.

Above all, the Scenario Analysis initiative has aspired to help government officials, environmental advocates, and other stakeholders, understand possible outcomes and consequences of pursuing one technology path over another and what might be needed for deploying a preferred option. It is intended that interested parties use the results as a basis for further discussion in other forums about any preferred outcomes; likely (or unlikely) technology paths given today's policy and market conditions; or paths that might need policy changes to induce private investment in that path for attaining certain outcomes. For example, if the combination of market forces and current array of public policies do not stimulate investment in a robust set of the desired resources, additional public policies and market incentives—or the removal of disincentives—may be needed.

1.2 The Scenario Analysis Process

For the Scenario Analysis project, the ISO created a Steering Committee, which includes representatives from the New England Conference of Public Utilities Commissioners (NECPUC), the New England Power Pool (NEPOOL), and ISO staff.[11,12] The committee's role was to generally guide the process, structure the stakeholder meetings, and review and comment on discussion documents.

Through a series of open meetings, committees, and technical working groups, the ISO has worked directly with stakeholders to develop the scenarios and assumptions Participation has been strong and has included broad representation from the industry as well as a range of state government agencies, including electric utility and environmental regulators. As a result, the ISO has heard many diverse views and has received and incorporated many technical comments on how the simulations should treat various technologies, systems, and other issues[13]

The depth and breadth of the results have been strengthened by the diversity of data sources used in the analysis. In addition to incorporating data provided by stakeholders, the ISO used data from consultants, academia, trade associations, governmental sources, and leading experts in the field. These data were essential for defining appropriate assumptions and capturing more widely accepted ranges for a number of the simulations conducted.

1.3 Overview of the Assumptions and Approach

The analysis generated a common set of assumptions about certain elements of the future state of the New England electric power system in 2020 to 2025 and beyond. These included an assumed system peak demand of 35,000 MW that new demand and supply resources, together with the existing system, must have the capacity to reliably supply. Assumptions were also estimated for future fuel prices, the future capabilities of today's fleet of generating units, and transmission and distribution facilities. To determine how sensitive the results were to changes in a number of other variables, such as higher and lower forecasts for fuel prices, the ISO used alternative assumptions for these variables.

Accounting for these assumptions and sensitivities, the ISO modeled how the various combinations of resources in each scenario could perform in supplying customers' electricity needs. A series of economic, reliability, and environmental, "outcome" metrics allowed for comparing the results of the different scenarios. Although limited in scope, the results of each modeling run provide a picture of

[11] The New England Conference of Public Utilities Commissioners, Inc. is a nonprofit corporation comprising the utility regulators of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that provides regulatory assistance about electricity, gas, telecommunications, and water industry issues of common concern to the six New England states. Additional information can be obtained online at http://www.necpuc.org/.

[12] NEPOOL was formed 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 serve as ISO stakeholders and market participants. For more information on NEPOOL participants, see http://www.iso-ne.com/committees/nepool_part/index.html#top.

[13] The working groups specifically addressed environmental, power supply, transmission, energy efficiency, and demand-response issues.

how the electric power system's costs, reliability, and environmental impacts could vary, given changes in the technology path and sensitivity to some key variables.

The scenarios selected for modeling and analysis did not attempt to identify "right" or "wrong" electric technologies or develop a plan for what the region *should* do. Nor did it attempt to build consensus about which technology path or outcomes are preferable. Additionally, it was not designed to show what actual futures *will* occur but rather to explore the set of diverse economic, reliability, and environmental impacts or outcomes that *might* reasonably be expected to occur *if* one energy path were pursued over another. The analysis specifically is not a least-cost plan or a multi-year present-worth analysis.

That said, the ISO appreciates the challenges in modeling future states of the region's electric power system. Inherent limits to the type of "what if" analyses attempted for this initiative include the ability of quantitative models and other tools to depict how the system would actually operate if the assumed conditions occurred in the future, the ability to predict how the electric system interacts with other elements of the economy, and so forth. For this reason, this effort has had to both simplify key elements of the system and qualify its results as being informative of—rather than deterministic about—how future electric technology choices will play out in the region's electric energy system. Additionally, by purposefully adopting scenarios with an exaggerated mixes of new capacity from one particular resource or another, the process has dramatized the differences among the scenarios. This deliberately provides distinct and clear pictures of possible future states that can be compared readily, rather than realistic pictures of the future.

1.4 Overview of the Scenarios

The Scenario Analysis examined seven different technology paths for New England, which emphasize both supply-side and demand-side options. The seven scenarios, as summarized below, varied according to the type of new electricity resource assumed to be added to the system:

- **Scenario #1—The "Queue" Mix.** This scenario reflects the mix of generating technologies currently being proposed in New England, notably gas-fired "peaking" units, combined-cycle (CC) units, and renewable resources. The mix reflects the proportion of the mix of generating resources in the ISO Generator Interconnection Queue as of September 30, 2006.[14]

- **Scenario #2—Demand-Side Resources.** This scenario shows significant investment in demand-side resources, including an aggregate of energy-efficiency technologies that reduce or shift load (i.e., customer usage) from on-peak to off-peak hours and measures that send price signals to customers to curtail their use in certain high peak-demand periods.

- **Scenario #3—Expansion of Nuclear Capacity.** For this scenario, nuclear capacity is expanded at or near existing nuclear stations.

- **Scenario #4—New Coal-Fired Power Plants Using Integrated Gasification Combined-Cycle (IGCC) Technology.** This scenario involves adding an advanced coal technology,

[14] The ISO's Generator Interconnection Queue is a list of the requests submitted to the ISO to conduct studies on interconnecting specific power plants to the region's electric power grid. While projects in the queue may not actually be permitted, financed, or constructed, the mix of projects in the queue is a reasonable approximation of the market's response to current conditions and outlooks in the region and private stakeholders' interest in developing projects to meet future requirements in the absence of changes in policy.

IGCC, to generate electricity and add to the capacity mix in New England. Unlike conventional coal plants, this technology gasifies the coal, thus allowing separation of useful energy and waste by-products. After separating the by-products, the gas stream passes through a combined-cycle production facility.

- **Scenario #5—New Natural-Gas-Fired Combined-Cycle (NGCC) Power Plants.** This scenario adds new gas-fired combined-cycle power plants similar to those added in large numbers in the region over the past decade.

- **Scenario #6—New Renewable Projects.** This scenario adds capacity from new renewable resources, as defined in the states' Renewable Portfolio Standards (RPSs).[15] These resources include onshore and offshore wind, hydroelectric, biomass, landfill gas (LFG), solar photovoltaic (PV), fuel cells, and combined heat and power (CHP) systems. This scenario reflects the effects of expanded state RPSs, which may be in the range of 20 to 25% by 2025.[16]

- **Scenario #7—Increased Imports of Hydroelectric Power and Other Low-Emission Resources.** This scenario adds new imports of hydro or other low-emission resources from Canadian provinces to the north (Quebec and the Atlantic and Maritime provinces), as well as from the west (New York and Ontario).[17] This scenario takes into consideration the different seasonal demand patterns experienced in Canada (winter peaking) and New England (summer peaking) and improves the use of planned hydroelectric and wind projects.

1.5 Outline of the Report

Following this introductory section, Section 2 describes the basis for the common assumptions about New England's future electricity system that were incorporated into the analysis. The methodology, models, and metrics used to analyze the various technology paths are summarized in Section 3. Section 4 provides more details about each scenario, along with the sensitivity analyses performed in studying each scenario, and Section 5 presents some of the key results of the analyses, comparing the results for various technology paths and sensitivities. Section 6 discusses the results and how policymakers and other stakeholders might be able to incorporate them into other analyses more specific to their needs.

The reference section contains a complete list of the data sources used. A series of links to Web pages that contain more detailed results are provided throughout the report.

[15] Renewable Portfolio Standards are state standards for load-serving entities to provide a portion of their energy from specific renewable technologies, this portion increasing each year. Maine, Massachusetts, Rhode Island, and Vermont have RSPs, and New Hampshire has recently established one. The definition of RPS requirements varies by state.

[16] Rhode Island's RPS requirement grows to 19%, and New Hampshire recently passed an RPS bill that seeks to have 25% of renewable resources by 2025. Except for Maine, the other states have lower percentage RPS targets but could increase them in the future.

[17] Atlantic Canada, also known as the Atlantic provinces, comprises four provinces located on the Atlantic Coast: the three maritime provinces of New Brunswick, Nova Scotia, and Prince Edward Island, as well as the province of Newfoundland and Labrador.

Section 2 Assumptions

To facilitate a comparison of the results, each technology path was based on a common set of assumptions about the bulk power system. Additionally, more specific assumptions were made about each technology path. This section summarizes the major assumptions incorporated into the models and post-processing calculations (discussed in Section 3). These assumptions are explained in more detail on the ISO Web site and reflect input from the open stakeholder process.

2.1 Systemwide Assumptions

The common set of assumptions addressed the following characteristics of the power system in the 2020 to 2025 timeframe and beyond:

- Summer peak demand
- New resource level
- The mix of resources (i.e., fuel diversity)
- Expansion of the transmission and distribution systems
- Prices of fuels

2.1.1 Target Peak Demand

With approximately 31,000 MW of generating capacity expected to be available in summer 2007 to meet a projected summer peak demand of 27,360 MW, the region currently has sufficient supplies to reliably meet customers' needs. But the starting premise for the Scenario Analysis was that electricity demand in the region will continue to grow, and to reliably meet this future demand, some combination of demand-side resources, new power plants, and transmission expansion, will be needed. To reflect customer requirements beyond the 2020 to 2025 timeframe, all seven scenarios assumed that the system will need to meet a summer peak demand of 35,000 megawatts (MW).[18,19]

Because the Scenario Analysis treats incremental demand-side resources on the same basis as other supply-side resources as opposed to simply treating them as reducing New England load, this planning target level for demand is assumed to be needed in the absence of new demand-side measures. Scenario #2 focuses on adding significant new demand-side resources to meet the summer-peak demand. One sensitivity case for all the scenarios (see Section 3.2.2) assumes that if 3,500 MW of energy-efficiency and demand-response resources were available to lower the summer peak demand, 3,500 MW of the new generating resources may not be needed.

[18] The 35,000 MW level is based on a 50/50 summer-peak demand, which is expected to occur at a temperature of 90.4°F and has a 50% chance of being exceeded due to weather.

[19] The analysis assumes the same load-duration curve (i.e., the relative or absolute level of demand, measured in megawatts, in each hour of the year) that was assumed for calendar year 2015 in RSP06.

2.1.2 New Resource Level

To meet this future level of demand, the Scenario Analysis assumed that 8,000 MW of new resources would need to be added to the existing resource mix to serve customer requirements. Consistent with the ISO's system planning criteria and practices, the analysis assumed that this level of resources would be needed to reliably meet customers' requirements without involuntary interruptions of service under a range of forecast system loads, resource conditions, and the ability of New England and neighboring systems to provide emergency capacity.[20]

The 8,000 MW level of new resources and total system capacity level of about 39,000 MW—which is greater than the existing supply-side power production, transmission import, and demand-reduction capacity currently installed in the region or discussed in the ISO's most recent long-range system plan—is large but not unrealistic.[21] For example, a decade ago in summer 1998, the region had 23,171 MW of capacity to meet a summer peak demand of 21,406; this provided a relatively slim margin of reserve supplies.[22] From then until summer 2006, the region had added over 7,500 MW of additional net supply, not counting the demand-side resources that had been added during the decade.[23] Customers' electricity use set a new record peak at 28,021 MW in August 2006—up over 6,500 MW from a decade ago.[24] The target of an additional 8,000 MW of new resources for no earlier than the 2020 to 2025 timeframe thus seemed a reasonable point to begin the analysis.

2.1.3 Resource Mix

Adding 8,000 MW to the existing mix of resources, means that all of the scenarios will still depend heavily on the existing fossil-fired generating capacity, even when it is assumed other technologies and resources will be added in the future. Of the roughly 31,000 MW of power production capacity in place today, about two-fifths use natural gas as its primary fuel, one-tenth uses coal, one-fourth uses oil, one-sixth is nuclear capacity, and approximately one-tenth uses renewable resources. This mix is shown in Figure 1.

[20] The ISO system must comply with Northeast Power Coordinating Council (NPCC) resource adequacy criterion, which states that the "probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in 10 years." Compliance with the criterion can be achieved, in part, through the use of operating procedures designed to mitigate capacity deficiencies and more likely to be invoked during periods of extremely high loads or severe generator-outage conditions. For additional information about the criterion, see http://www.npcc.org/criteria.asp.

[21] RSP06

[22] 1999 CELT Report (Holyoke: ISO New England Inc., 1999) Section 1. This peak load was the actual metered load of the region during summer 1998; the planning target for the summer peak had been 22,108 MW, reflecting what would have been expected under more normal weather conditions. This capacity figure reflects utility-owned generation, nonutility generation, and firm purchases and sales of capacity from other regions.

[23] In summer 2006, net installed capacity (including firm purchases of power from outside the region) totaled 30,895 MW. [2006 CELT Report (Holyoke: ISO New England Inc.: 2006), Section 1].

[24] "New England Consumers Set New Record for Electricy Use" (press release) (Holyoke: ISO New England Inc., August 2, 2006). Available online at http://www.iso-ne.com/nwsiss/pr/2006/august_2_2006_record_breaking_demand.pdf.

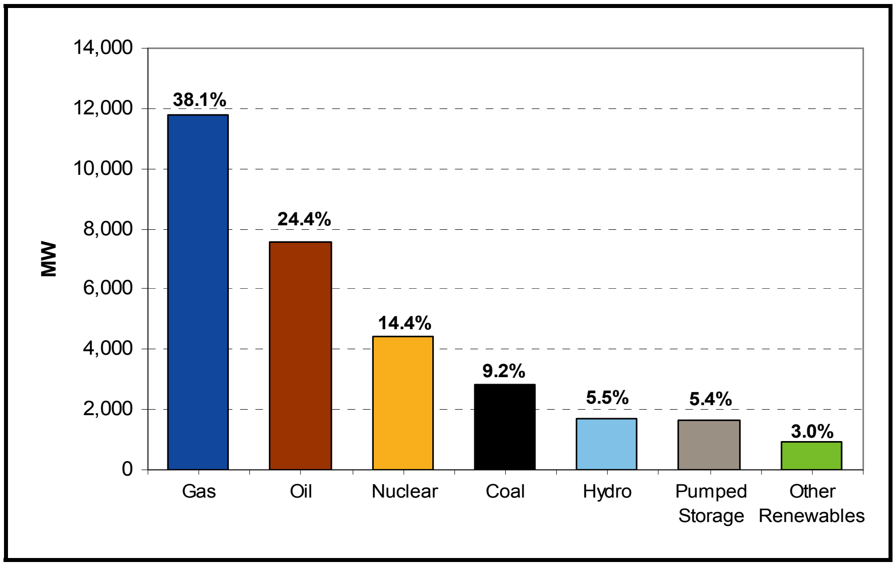

Figure 1: New England generating capacity by fuel type, 2006.

Note: Some plants tend to operate more often than these percentages indicate. For example, nuclear plants tend to produce more than one-sixth of the electric energy because they typically operate around-the-clock when not out for maintenance. Depending on the relative prices of fossil fuel, some plants run less often; for example, many oil-fired "peaking" units operate only rarely as a result of their relatively high operating costs.

Source: ISO New England, *2006 Regional System Plan* (RSP), Figure 4.1.

Of the 8,000 MW of new resources assumed to be added to the system's existing fleet of generation units, the first 2,600 MW is assumed to be a mixture of technologies that are already in the "development pipeline." This is indicated by the ISO's Generator Interconnection Queue as of September 30, 2006, when the Scenario Analysis initiative began. The Scenario Analysis assumes that the 2,600 MW portfolio of technologies in the queue, which includes wind projects, biomass and landfill gas projects, hydro projects, fuel cell installations, gas-fired combustion turbines and combined-cycle facilities, and IGCC projects, represents a reasonable mix of possible future resources. Figure 2 shows the mix of generation technologies in the queue as of September 30, 2006.[25]

[25] The queue includes many proposed projects, and past experience indicates that many of these are never built for a variety of reasons. The queue nevertheless represents a snapshot in time of what the market is proposing for a mix of resources.

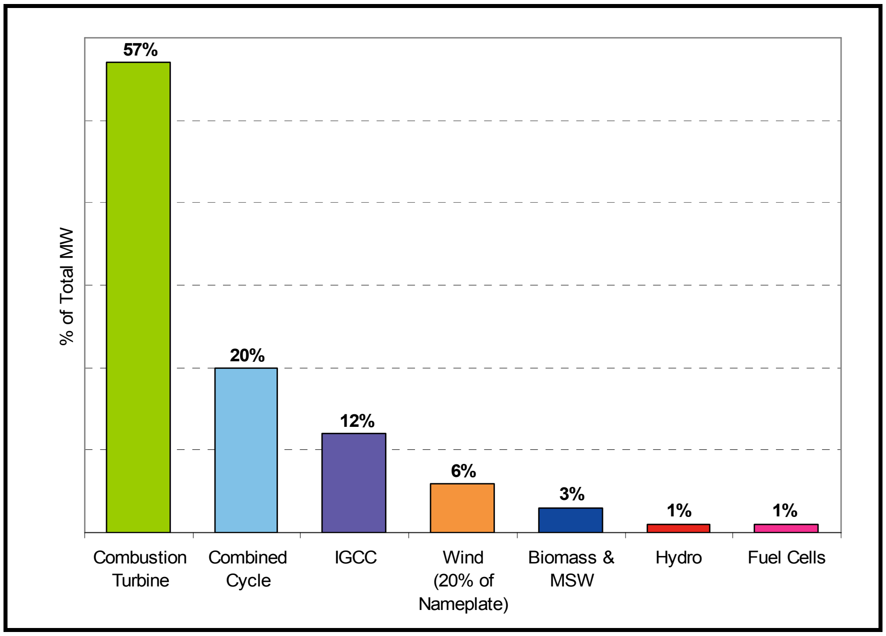

Figure 2: The mix of fuels for proposed power plants in the ISO's Generator Interconnection Queue as of September 30, 2006.

After adding this same 2,600 MW blend of technologies, each of the scenarios make up the remaining 5,400 MW of the total 8,000 MW of needed resources with a different technology path (as explained in more detail in Section 4). Having each scenario reflect a single dominant supply-side or demand-side technology path for the remaining 5,400 MW distinguishes the differences in each path's economic, reliability, and environmental outcomes, more so than scenarios with less varied technology bundles. While it may be unlikely that a single technology or resource type will dominate future electricity developments, such an outcome has been the recent experience in New England.[26]

2.1.4 Physical Configuration of the System

Also common to all the scenarios and simulation models are assumptions about the physical configuration of the electric power system. New England's electric transmission system is a complex array of interconnected transmission facilities linking generation units and customers' loads. The system includes 8,000 miles of high-voltage lines within New England and 12 tie lines interconnecting New England to three neighboring regions.

To simplify the modeling in the Scenario Analysis, however, these simulations assume a single "one-bus" model of the system (as if it did not experience any transmission congestion). This is consistent with the assumption that the transmission system will undergo normal expansion as part of the region's transmission planning process, which will effectively eliminate regional price differences within New England. To account for additional costs for generic transmission expansion for each of the scenarios, assumptions were made for mileage ranges, installed costs per mile of transmission, necessary acreage for rights-of-way, and substation equipment.

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[26] Notably, over 96% of the new power plants added in New England were gas-fired combined-cycle units, accounting for over 90% of the capacity added since 1999. (RSP06)

Similarly, the Scenario Analysis assumed that the local distribution system (i.e., the carrying power from the high-voltage system to customers' premises) will be expanded as needed, except for the scenarios with demand-side resources, which in theory account for a reduced need for the expansion of distribution infrastructure.

2.1.5 Fuel Prices

All seven of the scenarios were analyzed with common assumptions about the level and prices of fossil fuels used to generate the region's electricity: oil, natural gas, and coal. The starting point was a "base-case" fuel-price forecast built around what is considered to be the "conventional wisdom" regarding fossil fuel markets.[27] These prices for 2020 are shown in Table 1. This conventional-wisdom forecast assumed relative stability in the fuel-producing regions and continued development of additional supplies of fossil fuels. Specifically, the forecast assumed the following: relative stability in OPEC nations; new oil supplies from Alberta tar sands, the former Soviet Union, and ultra-deepwater sources; steady worldwide investment in exploration and production; the gradual development of new natural gas reserves; moderate worldwide oil demand growth; and the development of new U.S. supplies in the Alaska North Slope and Gulf offshore areas. In addition, the fuel prices include transportation costs to New England.

On the basis of these assumptions, the relative prices for fossil fuels are comparable to recent experience.

Table 1
Forecasted Scenario Analysis Fossil Fuel Prices for 2020,
2006 $/Million Btu

Natural Gas[(a)]	Residual Oil (0.3% Sulfur)	Distillate Oil	Appalachian Coal	Imported Coal
6.16	7.03	11.93	2.00	2.11

(a) For natural gas, a monthly price profile was developed to reflect typical historical patterns across the year to capture seasonal differences.

While electricity prices in the region have consistently been higher than the national average for many decades, more recently, prices have risen significantly.[28] This is, in part, a result of the region's reliance on natural gas—a fuel whose prices have more than doubled from their pre-2000 levels.[29,30] In 2000, gas was used to produce 16% of the region's electricity; in 2006, this percentage had risen to

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[27] Levitan and Associates, Inc. (LAI). *Scenario Analysis Project— Long Term Forecast of Oil, Natural Gas and Coal Prices In New England*, March 22, 2007).(March 22 2007). Available online at http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/apr22007/fuel-price-forecast.pdf.

[28] Tierney, Susan. *Analysis of Energy Information Administration Form 826 Data*. Presentation to the 100th Massachusetts Restructuring Roundtable, March 30, 2007. Available online at http://www.raabassociates.org/Articles/Tierney%20Presentation_3-30-07.ppt.

[29] See the *2005 Annual Markets Report* (hereafter cited as AMR05) (Holyoke: ISO New England Inc., June 1, 2006), available online at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2005/2005_annual_markets_report.pdf. Also see Electricity Cost White Paper (Holyoke: ISO New England, 2006), available online at http://www.iso-ne.com/pubs/whtpprs/elec_costs_wht_ppr.pdf. This paper discusses the links between wholesale electric energy prices in New England and the price of natural gas.

[30] From 1990 through 1999, wellhead prices for natural gas in the U.S. averaged $1.92 per thousand cubic feet (cf) of gas; after 2000, annual wellhead prices for natural gas have been considerably higher: $3.68 in 2000, $4.00 in 2001, $2.95 in 2002, $4.88 in 2003, $5.46 in 2004, $7.33 in 2005, $6.42 (estimated) for 2006. Source of wellhead data:
http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/historical_natural_gas_annual/current/pdf/table_07.pdf;
http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/natural_gas_monthly/current/pdf/table_04.pdf.

40%, with gas- and gas-oil-fired power plants setting the price in New England's energy market in over 80% of the hours of the year. In the scenarios, it was assumed that the price of natural gas would vary seasonally, but would not change as a result of differences in the demand for natural gas associated with the various scenarios.

2.2 Technology-Specific Assumptions

In addition to systemwide assumptions, the analysis incorporated a number of assumptions in the following categories specific to each technology:

- Each technology's capacity value, ability to produce electric energy, and operating characteristics
- Annual capital cost requirements
- Emission rates of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and carbon dioxide (CO_2) for units that burn fossil fuels
- Value (or cost) for emission allowances
- Amount of water that would be needed for cooling purposes for some types of major new power plants
- Amount of land that would be required to site various types of infrastructure, including new supply-side resources and transmission lines that some technologies would presumably need

2.2.1 Availability of Capacity and Ability to Produce Electric Energy

Each type of resource is associated with a capacity value (CV) and ability to produce electric energy. The CV variable represents the resource's seasonal capability taking into account its planned and forced outages.[31] The CVs for resource additions were assumed to be the same in all scenarios. Assumptions for the ability of a technology to produce electric energy were generated on the basis of the availability of the technology's fuel source or its dependence on system load levels, as is the case with demand-side resources. The availability factors for most generating units reflect industry averages based on recent experience. Because the functional characteristics of intermittent resources are highly dependent on location and time, the modeling of generic intermittent resources required additional considerations.

The ability of photovoltaic and wind facilities to produce electricity is directly tied to the availability of the light or wind at a specific location, time of day, and season (among other factors), as well as the engineering performance of the energy-conversion equipment (e.g., the PV panels and wind turbines).

Solar PV energy profiles were developed from many years' worth of hourly solar measurements taken at two representative sites: Hartford and Boston. The profiles for the two sites were then

[31] A *planned outage* is the planned inoperability of a generator, generally to perform maintenance. A *forced outage* is a type of unplanned outage that involves the unexpected removal from service of a generating unit, transmission facility, or other facility or portion of a facility due to an emergency failure or the discovery of a problem. These problems must be repaired as soon as crews, equipment, corrective dispatch actions, or a combination of all measures can be activated to allow the work to be performed.

integrated into one representative New England PV site for the modeling of this resource in Scenario #6.[32] Solar photovoltaics were assumed to have a capacity value of 40% during the summer and 5% during the winter.

Similar to the PV profile, to model wind as a energy resource in New England, hourly, monthly, and annual wind energy profiles were developed for two representative New England inland wind sites and three offshore wind sites.[33] Composite monthly profiles were then developed for both the inland and offshore sites. Overall, onshore wind had a capacity value of 19% for summer and 41% for winter. Offshore wind had summer and winter capacity values of 26% and 47%, respectively. Actual installations of wind resources could have substantially different values.

Demand-side resources were represented in the Scenario Analysis by demand- (and price-) response and energy-efficiency (EE) resources. Demand-response resources reduce the system load when the ISO calls on them to do so because the system has a deficiency of electric generating resources, including imports, for operating the system. Price-response resources reduce demand because wholesale electric energy prices are high. Energy-efficiency programs reduce the use of electricity over considerable hours of the year and include the permanent installation of devices, such as compact fluorescent lighting, efficient pumps and motors, refrigerators, air conditioners, and other efficient equipment. Because demand-response and energy-efficiency resources for this scenario analysis represent the aggregate electrical characteristics of many thousands of demand-side resources together, and not one particular technology, the “availability” of some demand-side resources is affected by the mix of measures in place (e.g., the installation of high-efficiency air conditioners) and the demand at different times of year (i.e., winter, when an efficient air conditioner would not reduce electricity usage). Thus, the ability of certain demand-reduction measures to reduce customer usage depends, in part, on the technical fit between the demand-reduction measures and the time(s) of day or season(s) of the year when the affected equipment or appliance would otherwise have been used. Some technologies also shift load from peak periods to times of reduced systemwide load.

For this analysis, demand response was modeled assuming a reduction in demand without any generation turned on “behind the meter,” which would reduce the net load experienced by the system. Only the highest systemwide loads of the year were reduced. Energy efficiency was modeled as large load reductions at times of highest systemwide demand and as small load reductions during periods of lowest systemwide demand.

2.2.2 Plant Operating Characteristics and Costs

Data assumptions for plant operating characteristics and total plant capital costs for each of the expansion technologies are summarized in Table 2. The operating characteristics and costs for existing power plants are based on actual data for each type of plant as reflected in the RSP06 database. To determine operating characteristics and costs for new demand-side technologies and power generation resources added in each of the scenarios, the analysis incorporated information from published reports, manufacturers, developers, and others sources. The cost assumptions for energy efficiency and demand-response measures were developed from historical demand-side program costs as reported by the states or to them from the utilities implementing such programs.

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[32] See slides 12 and 13 in the linked solar PV energy profile.

[33] LAI. *Technical Assessment of Onshore and Offshore Wind Generation Potential in New England*, Boston: Levitan and Associates, Inc.. May 1, 2007. Report is available online at: http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/may212007/levitan_wind_study.pdf.

Table 2
Major Assumptions for Plant Operating Characteristics

Technology	Energy Source	Unit Size (MW)	Heat Rate (Btu/kWh)(a)	Annual Capital Costs (2006 $/kW)	Sources[b]
IGCC	Appalachian coal	600	8,600	2,500–3,500	EPA, EPRI, MIT, DOE
IGCC with carbon capture	Appalachian coal	600	9,750	2,900–3,900	EPA, EPRI, UN, MIT
Combined cycle	natural gas	400	6,500	800–1,000	GE
Combustion turbine	natural gas	100	8,500	500–700	GE
Nuclear	uranium	1,080	10,000	3,000–5,000	Westinghouse, NEI
Fuel cell[c]	natural gas	1	8,000	3,500–4,000	Fuel Cell Energy
Biomass	wood chips	40	14,000	2,500–3,500	CT Projects, NH DES
Hydro	water	5	N/A	3,000–4,000	NE Developer
Landfill gas	landfill gas	5	10,500	2,000–2,500	NE Plants
Combined heat and power[c]	natural gas	5	9,750	1,000–1,500	Solar Turbines
Solar photovoltaic	sun	1	N/A	4,000–6,000	UMASS RERL
Onshore wind	wind	1.5	N/A	1,500-2000	UMASS RERL, Levitan
Offshore wind	wind	3.5	N/A	2,000–2,500	UMASS RERL, Levitan

(a) A plant's heat rate is its operating efficiency for converting fuel to electricity.

(b) See the List of Resources for complete citation information.

(c) The fuel cell and CHP distributed generation systems are typically installed at a larger facility like a university hospital. These technologies offer dual benefits of electricity production and the use of the exhaust heat for heating, process steam, hot water, and other applications. The heat rates and capital costs of these technologies reflect only the production of electricity and not the use of the exhaust heat.

Clearly, adding new gas-fired power plants, nuclear capacity, demand-side resources, and so forth, have associated investment costs. The analysis assumes that under all scenarios, the regional natural gas delivery system will undergo a baseline expansion to accommodate futuregas needs in the region. A common fuel-supply assumption across all scenarios and all sensitivity cases is that the Canaport LNG project in St. John, New Brunswick, is commercialized.[34] The capital costs for new energy resources were analyzed as cost ranges reflecting the addition of each supply-side or demand-side technology, including any load-serving entity (LSE) costs.[35]

All but Scenario #7 (the import scenario) involved capital investment associated with the electric power resource itself, that is, the nuclear capacity, the gas-fired generation units, the advanced coal-fired power plants, the demand-side measures, or the renewable power facilities. No capital costs for resources supplying the hydro imports or other resources with low emissions were added for Scenario #7 because it was assumed that infrastructure for this scenario already exists or would be built (and paid for) in neighboring regions. For example, because load peaks in Canada during the winter, Canada may have extra capability to export hydro resources during the summer when most

[34] Respol/Irving. Additional information is available online at http://www.canaportlng.com.

[35] A *load-serving entity* secures electric energy, transmission service, and related services to serve the demand of its customers.

needed in New England. However, the capital investment costs for Scenario #7 were tied to the new high-voltage transmission additions that would be needed to reliably import significant new power supplies from these neighboring systems.

Scenario #4 includes a sensitivity case in which facilities are built for carbon capture and sequestration (as opposed to constructing facilities without that feature) and for adding the capability to actually sequester carbon emissions from the facility.

2.2.3 Air Emissions, Control Measures, and Costs

Environmental impacts from generating plants, particularly air emissions released from coal and oil-fired facilities, are a continuing issue in the region. Emissions of sulfur dioxide, nitrogen oxides, carbon dioxide, and mercury (Hg) are all concerns. NO_X emissions are of interest because they contribute to the formation of smog, especially during summertime conditions—the very periods when the region's electricity use and power production peaks. NO_X emissions are typically higher on days with high electricity use when a considerable amount of peaking units are run to produce power for short periods of time, but total year-round emissions of NO_X are significant as well. Sulfur dioxide is a main contributor to acid rain, and mercury emissions have been shown to have detrimental health effects.[36] Carbon dioxide emissions have been linked to climate change.[37]

Existing federal and regional regulations and those under development will require existing and new generators to further reduce these pollutants in the timeframe of this analysis. These regulations include the Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) and state implementation of these, the Ozone Transport Commission's (OTC) High Electric Demand Day (HEDD) Initiative, and the Regional Greenhouse Gas Initiative (RGGI), a northeastern 10-state voluntary CO_2 cap-and-trade program being implemented.[38] The Scenario Analysis did not explicitly model meeting these regulations but produced emission estimates for examining the relative differences among the scenarios and sensitivities.

To comply with these regulations, generators would have to install emissions control equipment or take other measures, such as switching the type of fuel used, to physically and chemically reduce the amounts of emissions. One measure to control CO_2 emissions is *carbon sequestration*, which involves carbon capture, transport, and permanent storage.[39] Operating costs for these controls add to a fossil fuel generator's total variable costs and are not yet economically available. The analysis examined the impact of using CO_2 sequestration as an IGCC scenario sensitivity case.

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[36] U.S. EPA. Mercury Web page, http://www.epa.gov/mercury/index.htm. Accessed April 23, 2007.
http://www.epa.gov/interstateairquality/; http://www.epa.gov/camr/; http://www.rggi.org/about.htm

[37] Intergovernmental Panel on Climate Change Working Group 1.Physical Science Basis; Fourth Assessment Report of the IPCC, *Summary for Policymakers* (World Meteorological Organization and United Nations Environment Programme, April 2007). Available online at http://www.ipcc.ch/WG1_SPM_17Apr07.pdf.

[38] The HEDD initiative is a multi-state effort but only affects Connecticut in New England.

[39] Several possible methods exist for sequestering carbon. They include the geological storage of CO_2 (deep injection into the ground), ocean storage, biological processes, and afforestation, which is a current practical option being conducted by many companies around the country. In 2003, the top 10 U.S. companies in this field sequestered about eight million tons of CO_2 mainly through forestry practices. (See http://www.treepower.org/EIA2004/main.html.)

2.2.3.1 SO_2, NO_X, and CO_2 Emission Rates

Table 3 shows the emission rates assumed for SO_2, NO_X, and CO_2 for the generating resources modeled in the analysis. The emission rates for existing power plants were principally based on data from U.S. EPA databases. No changes were made in the existing system emission rates since these would be difficult to estimate for the future period and would not significantly influence the relative differences among the scenarios. It was assumed that these relatively current emissions rates for these types of power plants will be in place in 2020.

Table 3
Emission Rate Assumptions for 2020

Technology	Unit Size (MW)	SO_2 (lbs/MBtu)	NO_X (lbs/MBtu)	CO_2 (lbs/MBtu)	Reference[a]
IGCC[b]	600.0	0.0300	0.0100	210.0	EPA, EPRI, MIT, DOE
IGCC with carbon capture[b]	600.0	0.0300	0.0100	21.0	EPA, EPRI, UN, MIT
Combined cycle[c]	400.0	0.0006	0.0100	120.0	GE
Combustion turbine	100.0	0.0006	0.0300	120.0	GE
Nuclear	1,080.0	none	none	none	Westinghouse, NEI
Fuel cell	1.0	0.0006	0.0088	120.0	Fuel Cell Energy
Biomass	40.0	0.0200	0.0750	170.0	CT Projects, NH DES
Small hydro	5.0	none	none	none	NE Developer
Landfill gas	5.0	0.0200	0.0300	0.0	NE Plants
Combined heat and power	5.0	0.0006	0.0140	120.0	Solar Turbines
Solar photovoltaic	1.0	none	none	none	UMASS RERL
Onshore wind	1.5	none	none	none	UMASS RERL, Levitan
Offshore wind	3.5	none	none	none	UMASS RERL, Levitan

(a) See the List of Resources for complete citation information.

(b)The emission rates from IGCC plants typically are lower than the emission rates for existing coal plants.

(c)New combined-cycle plants are assumed to be more efficient than existing facilities, thus emission rates for the new facilities are assumed to be lower than for the existing fleet.

While SO_2 and NO_X emissions from electric power generators have been decreasing in the region, directly attributable to compliance with environmental regulations, total CO_2 emissions have been increasing. Starting in 2009, RGGI will allocate 55.8 million tons of CO_2 emission allowances to the New England states and require these and other RGGI states to limit emissions from regional fossil fuel power generators that are 25 MW and larger. The overall cap on emissions is set at 1990 emission levels for this region. By 2018, the cap will decrease 10% (with 50.2 million tons of allowances allocated to New England).[40]The Scenario Analysis shows the total CO_2 emissions for the region and compares it to the 50.2-million-ton allocation under the assumptions for each scenario.

[40] The region will need to either reduce emissions to the 1990 level or trade emission allowances with other states in the Northeast region, which includes New York, New Jersey, Maryland, and Delaware.

Table 4 shows the assumptions for emission values in 2020, which were used to determine the dispatch emission cost adders for each type of generating technology.

Table 4
Emission Value Assumptions

Emission	Emission Value (2006 $/ton)	Source(a)
SO_2	969	EIA
NO_X	2,345	EIA
CO_2	3, 20, and 40	Synapse Report

(a) See the List of References for additional citation information.

Scenario #4 (IGCC) assumed no carbon sequestration. However, a sensitivity case represented carbon capture, which assumed that ocean sequestration would be possible. A sequestration cost of $25/ton of CO_2 was assumed for this case, for transportation, monitoring, and storage. Higher plant capital costs (+400 $/kW) for the IGCC plants' capture of CO_2 and a 13% increase in the plant's heat rate were also assumed.

2.2.3.2 Emission Rate Adjustments for RGGI Requirements

The RGGI requirements exempt units less than 25 MW in size, existing biomass units that use more than 50% biomass fuel, and new biomass plants that use at least 95% biomass. Since the Scenario Analysis emission results reflect the total New England generation system, which includes these types of units, the CO_2 results needed to be adjusted to enable an "apples-to-apples" comparison of each scenario's CO_2 emissions with the RGGI CO_2 emission allocation for New England. Thus, for each applicable scenario and sensitivity case, the total CO_2 emissions for the smaller plants and the biomass plants were subtracted from the total emission results. This expected allocation for around 2020 is a 10% decrease from the initial allocation for 2009 to 2014.[41]

This analysis was based on emissions reported in the NEPOOL Generation Information System (GIS) from 2005 and 2006 to estimate the CO_2 emissions from units less than 25 MW, plus the emissions from biomass units.[42] These GIS emissions were assumed to be the same for the RGGI-exempt units in the scenarios. Therefore, 5 million tons was subtracted for these non-RGGI units in all the scenarios except Scenario #6 (renewables). In this scenario, an additional 12 million tons was subtracted for a total of 17 million tons, since 675 MW of biomass units and 675 MW each of fuel cell and CHP units under 25 MW were added in this scenario.

2.2.3.3 Mercury Emission Rates

The analysis of the coal plants simulated mercury emissions on the basis of Appalachian coal having a mercury content of 5.7 lbs/trillion Btu before controls.[43] Since state mercury regulations are

[41] At a CO_2 base price of $20/ton, the use of offsets could help meet the RGGI allocation. But to be conservative, the expected allocation assumed no use of offsets, which could be 10% of the RGGI allocation on the basis of a CO_2 price over $10/ton.

[42] Add GIS citation.

[43] LAI Feb 2007 fuel-price forecast: Coal has been estimated to contain from 2.7 lb/TBtu (trillion Btu) to 5.5 lb/TBtu, depending on its source. Appalachian coal was assumed for the IGCC scenario. Add link.

focusing on a 90% removal requirement, it was assumed that the actual emissions would be about 10% of the number simulated for the scenarios.

2.2.4 Cooling Water Requirements

Because it was assumed that the Clean Water Act (CWA) will require new generating plants to use cooling towers, the Scenario Analysis developed assumptions for the rate of cooling water use for new larger power plants.[44]

2.2.5 Land Needed and Costs for Siting Infrastructure

Estimates were also made for the land needed to develop new generation and transmission for the various types of resources added in the scenarios. Estimates were generally based on the amount of land needed that would exclude public use. Similar to transmission rights-of-way, the analysis recognizes that wind sites might allow public use, such as for farming or recreation. For example, the water between offshore wind turbines could be used for boating and fishing. For transmission cost and land requirement assumptions, the ISO and the regional transmission owners developed conceptual generic costs for new transmission lines and substations needed to integrate new generation into each of the scenario's unique system structure.

The analyses assumed that central-station generating units (e.g., gas-fired power plants, nuclear plants, advanced coal plants), would be located relatively close to the load center and would require less significant transmission investments than remote sources of electricity (i.e., onshore and offshore wind and imports from neighboring systems). Since demand-side resources were assumed to not require transmission investment, no additional land use was assumed for this scenario.

[44] U.S. EPA, Cooling Water Intake Structures—Clean Water Act §316(b), Phase I—New Facilities. This section addresses the location, design, construction, and capacity standards for cooling water intake structures at new electric generating plants and manufacturers that use 25% or more of their intake water for cooling and withdraw more than two million gallons per day (MGD) from U.S. waters. New facilities with smaller cooling water intakes will still be regulated on a site-by-site basis. Additional information is available online at http://www.epa.gov/waterscience/316b/phase1/. Accessed May 8, 2007.

Section 3 Methodology

This section describes the analytic techniques and tools used to simulate and study the different scenarios. These tools simulated how electricity would be produced in the region, what it would cost to produce and purchase it, and what some of the environmental impacts could be, taking into account the existing fleet of power plants and the new resources added in each scenario.

Using the common set of assumptions for each scenario's set of available new resources (with their various operating characteristics), the simulation "dispatched" power plants to meet different levels of customer demand in every hour of the year being analyzed. These simulations established a "common-assumptions case" for each scenario based on the assumptions discussed in Section 2 and a wide array of information about how the electric power system "performed" from an economic, environmental, and reliability standpoint.

To capture a wider array of inputs and generate a broader set of results for each scenario, stakeholders requested variations of the parameters used in the common set of assumptions through a series of sensitivity analyses. Each sensitivity analysis ran additional simulations by, for example, varying the assumptions for forecasted levels of fossil fuel prices; the mix of new generation and demand-side resources; unit retirements; costs of CO_2 emission allowances; and the amount of imports available from neighboring regions.

3.1 Tools for Analyzing the Scenarios

The first part of the analytic process involved conducting three types of analyses for each scenario, as follows:

- Simulations of production costs
- "Post-processing" calculations that the initial simulations could not generate directly
- "Operable capability" analyses of various types of resources

3.1.1 Production Simulation Modeling Using the IREMM Model

To simulate the dispatch and estimate production costs for the New England electric system, the ISO used the Interregional Electric Market Model (IREMM), the same model previously used in the ISO's annual regional system planning process. The model provides production costs for each resource and aggregates total systemwide costs.

For each hour of the year being studied, IREMM simulates how power plants are called on in sequence to operate for reliably meeting the demand for electricity. Using assumptions about each power plant's heat rate, the type of fuel consumed, the costs for fuel, outage patterns for maintenance and repairs, and other data on operating performance and costs, the model dispatches resources from lowest to highest cost to meet each hour's demand.[45] IREMM models the dispatch of the power system around the clock for the total 8,760 hours of a single future year, simulating how the system can meet the variation in customers' demand each day and the peak demand during the summer and winter periods.[46, 47]

In the scenarios that reflect the addition of new supply-side generating resources (e.g., all scenarios besides Scenario #2, which adds 5,400 MW of demand-side resources), the model added power plants to the system's existing fleet and 2,600 MW of resources reflecting the fuel mix in the ISO's Generator Interconnection Queue. The model does not "dispatch" wind turbines and solar photovoltaics in the same way as other power plants. Because these types of facilities deliver power when the "fuel" or energy source (e.g., the wind or the sunshine) is available, the model injects a specific amount of electric energy into the grid according to preset profiles that reflect the "windiness" or amount of sunshine in different hours and months of the year.

Scenario #2 reflects how the system would respond to demand-side resources that lower customer requirements. The model captures reductions in the total system customer demand in appropriate hours instead of adding more generating resources to meet the 35,000 MW level of projected customer demand used in the other scenarios. This aggregate reduction in customer demand for this scenario reflects an amount of demand response and energy efficiency that reduces hourly energy demand by newly-installed efficiency measures. Thus demand-side measures were input directly into the model to represent hourly profiles of 2,700 MW of energy efficiency and 2,700 MW of demand response that will be available at the time of a 35,000 MW systemwide load. The scenario assumed that energy efficiency would "supply" (i.e., reduce energy demand) by a total of 18 million MWh [18 terawatt-hours (TWh)] of electric energy.[48]

Imports of hydro and other low-emission resources (Scenario #7) were modeled to account for the transmission of a high amount of electricity imported during periods when systemwide electric energy costs in New England would be high and a low amount of electricity imported during lower-cost, off-peak systemwide load periods.

3.1.2 Post-Processing Calculations

While the IREMM model results provide information about the cost, reliability, and emissions associated with each scenario's production of electric energy, the results of the model do not include information about a number of other economic metrics. These include the capital costs needed for investing in the expansion supply- and demand-side resources relied on to provide electric energy; the costs to cover each scenario's need for incremental transmission, distribution, and fuel (natural gas) delivery infrastructure; or the annual market revenues a new resource project could obtain from the

[45] Generating units and other resources are dispatched in *economic merit order.* That is, the dispatch process takes into account the relative costs of primary and alternate fuels at individual units and across generating units, their heat rates, and their planned and forced outages to model unit unavailability, which are accounted for as unit deratings (i.e., reductions in unit capability).

[46] In general, customer demand rises during the morning and afternoon as businesses open and households go about their business. The "shape" of customers' usage varies over the course of the year; for example, common patterns show afternoon electric loads being higher on hot summer days when the temperature and air-conditioning usage is the highest. The demand curve also shows rapid increases in usage on mornings due to the start-up of electric heat or cooling and other usage for office buildings. Weekends tend to have lower use generally, as do the daily peaks in the fall and spring seasons.

[47] The Scenario Analysis load curve under the common set of assumptions reflects the same shape as that used in the ISO's RSP06, expected for calendar year 2015.

[48] One terawatt is equivalent to 1,000 gigawatts (GW), one million megawatts, one billion kilowatts (kW), and one trillion watts (W).

wholesale energy markets. The IREMM simulations also did not account for physical resource needs for land and water use or adjust CO_2 emission values. Post-processing calculations were conducted to provide and compare these data.

3.1.3 Operable Capacity Analysis of Various Types of Resources

To analyze the degree to which New England has sufficient diversity of fuel supply, an operable capacity analysis (OCA) was performed consistent with the methodology followed for RSP06. This analysis simulated a hypothetical and temporary loss of specific fuel types used in each scenario to estimate the minimum amount of electricity generation by that fuel that would be essential for maintaining the reliability of system operations. The results identify the amount of supplemental dual-fuel capacity, external purchases, or other resources that would be needed to maintain system reliability. The Scenario Analysis performed an OCA for both summer and winter seasonal peaks for each of the major fuel types in the scenarios.

3.2 Sensitivity Analyses

IREMM was also used to conduct sensitivity analyses. These analyses varied the assumptions used in the simulations, taking into account different inputs appropriate to each different scenario and sensitivity parameters. Like in the simulations under the common set of assumptions, for each sensitivity run, the model responded to the changes in demand, generating resources, or a combination of both and dispatched them given the economics of each sensitivity's conditions.

For all the scenarios, sensitivities were run related to higher and lower fuel-price forecasts; retiring capacity and replacing it with the technology featured in the scenario; and higher and lower prices for carbon emission allowances. For all but Scenario #2 (demand-side resources), a sensitivity was run that added additional demand response and energy efficiency instead of the technology featured in the scenario. For Scenario #2 alone, however, a sensitivity case was run that interchanged the levels of demand response and energy efficiency. A sensitivity case for Scenario #4 (IGCC) considered the increased capital and operating costs associated with carbon sequestration. One sensitivity for Scenario #7 (imports) was to decrease the level of low-emission imports of electric energy but with the same 5,400 MW capacity. Counting the seven core scenario runs for the common set of assumptions, the scenario analyses conducted over 50 simulations, as shown in Table 5.

Table 5
The Seven Core Scenarios and Associated Sensitivity Analyses

		A	B	C	D	E	F	G	H	I	J	K
	Scenarios — incremental 8,000 MW All cases have the same 2,600 MW of resources reflecting proposals in the ISO queue as of 9/30/06.	**Common Assumptions**	**Low Gas Fuel Prices**	**High Gas Fuel Prices**	**Replace 3,500 MW of the Scenario Technology with 1,750 MW of Energy Efficiency (EE) and 1,750 MW of Demand Response (DR)**	**Replace 2,700 MW of DR with 2,700 MW of EE**	**Replace 2,700 MW of EE with 2,700 MW of DR**	**Retire 3,500 MW and Replace with Scenario Technology**	**Low Carbon−Allowance Prices**	**High Carbon−Allowance Prices**	**For Coal with Carbon Sequestration**	**Decreased Imports of Low−Emission Resources (−7 TWh)**
1	**Queue Mix —** combination of currently proposed resources; 5,400 MW blend reflecting the fuel mix exhibited recently by the market	X	X	X	X			X	X	X		
2	**Demand-side resources —** an additional 2,700 MW of DR and 2,700 MW of EE	X	X	X	(a)	X	X	X	X	X		
3	**Nuclear —** 5,400 MW	X	X	X	X			X	X	X		
4	**Advanced technology coal (IGCC) —** 5,400 MW without carbon sequestration	X	X	X	X			X	X	X	X	
5	**Natural gas (combined cycle) —** 5,400 MW	X	X	X	X			X	X	X		
6	**Renewables —** 5,400 MW, including a combo of on− and offshore wind, hydro, biomass, LFG, CHP, fuel cells, PV; 1/8 each	X	X	X	X			X	X	X		
7	**Increased imports of hydro and other low−emission resources —** 30 TWh of imports	X	X	X	X			X	X	X		X

(a) Case 2D is the same as case 2A.

3.2.1 Fuel-Price Sensitivity Cases

For all scenarios, two sensitivity cases decreased and increased the fuel prices upon which the "conventional wisdom" fuel-price forecast (as described in more detail in Section 2.1.5) was based. In the case with a high natural gas price, gas prices are twice as high as they are in the common-assumptions case. The price for distillate fuel oil is maintained at a level above that of the (doubled) gas price, and the price for residual fuel oil is kept at a price lower than natural gas. Coal prices do not change from the initial case. The intention in developing this outlook was to shift the relationship between natural gas prices and heavy oil prices and show a case in which natural gas prices become much less competitive compared with heavy oil prices.

By contrast, natural gas prices in the low-gas-price case are one-half the level shown under the common-assumption case. The price for distillate fuel oil is maintained at a level greater than the price of residual fuel oil, both of which have prices greater than the (one-half) price of natural gas. In essence, in this case, the coal and oil prices (for both distillate and residual oils) remain the same as in the common-assumption case.

3.2.2 Sensitivity Cases for Reducing Demand and Rebalancing Demand Response and Energy Efficiency

Another set of sensitivity cases analyzed the core scenarios that addressed a system that would need less than 5,400 MW of the scenario's core technology as a result of stronger demand-side resources occurring by the forecast year. For this set of cases, each scenario assumed that only 1,900 MW of the core scenario technology would need to be added in addition to the 3,500 MW of demand-side measures (i.e., 1,750 MW of energy-efficiency measures and 1,750 MW of demand-response measures). For Scenario #2, this sensitivity case was modified since the scenario consisted of energy efficiency and demand response. The first of these sensitivity cases examined a scenario composed solely of 5,400 MW of new energy efficiency (as opposed to 2,700 MW efficiency and 2,700 MW demand-response measures). The second version of this sensitivity case was based on 5,400 MW of demand response and no energy efficiency.

3.2.3 Unit Retirement Sensitivity Case

A "retirement" sensitivity case was analyzed for every scenario. For this case, in addition to the original assumed incremental addition of 8,000 MW of new capacity, more new scenario-technology capacity was added to counteract the effects of retiring 3,500 MW of generating capacity that exists as of 2007. In these sensitivity cases, a total of 11,500 MW of new capacity was added, of which 2,600 MW reflects the common mix in the Generator Interconnection Queue (i.e., a common-set assumption). All the remaining new capacity is composed of the scenario's core technology. For the case of imports, the capacity of the transmission interconnections was increased to 8,900 MW, and the amount of imported energy was increased from 30 million MWh to 50 million MWh.

3.2.4 Carbon-Allowance Price and Carbon Sequestration Sensitivity Cases

Each scenario also ran a sensitivity case for low and high prices for carbon-emission allowances (e.g., \$3/ton and \$40/ton, respectively.)[49] This sensitivity also serves as a proxy for changes in prices for other emission allowances. For Scenario # 4 (IGCC), a sensitivity case was run assuming that 90% of

[49] The stakeholders suggested the ISO use this range of CO_2 allowance prices based on a Synapse Economics report [Add citation.]

the CO_2 produced by the 5,400 MW would be captured at the plants and then transported and sequestered (permanently stored).[50]

3.2.5 Decreased Imports Sensitivity Case

For Scenario #7 (imports), a sensitivity was run in which only 23 million MWh rather than 30 million MWh would be imported via the new transmission ties at the same capacity cost for the transmission facilities. The same amount of transmission capacity would be needed despite the decreased availability of energy imports.

3.3 Metrics for Comparing the Scenarios

On the basis of the power plants dispatched for each scenario and sensitivity case, the post-processing calculations, and the operable capacity analysis, the ISO generated a variety of economic, reliability, and environmental metrics, as summarized in Table 6.

[50] The ISO assumed a $25/ton cost for transportation and sequestration based on ocean storage. [Add citation].

Table 6
Summary of Metrics for Comparing the Scenarios

Economic	Reliability	Environmental
Systemwide production costs[(a)] (billion $)	Systemwide energy mix (MWh; % MWh by fuel)	Total systemwide emissions of SO_2 and NO_X (1,000 tons) and CO_2 (million tons)
Energy supply duration curves for marginal clearing price	Systemwide capacity mix (MW by fuel)	Total systemwide NO_X emissions for the 10 highest peak-load summer days (tons)
Annual revenue requirements (ARR) for expansion resources[(b)] (billion $; $/kW-year)	Total units of fossil fuel burned (Quadrillion Btus consumed; MWh of production)	Total systemwide emissions of CO_2 (million tons)
Net wholesale electric energy market revenues for expansion resources (million $; $/kW-year)	Exposure to fuel-supply disruption (MW) (operable capacity analysis)	CO_2 emissions compared with Regional Greenhouse Gas Initiative allocation[(c)] (million tons; compliance/ noncompliance)
Load-serving entity expenses for wholesale electric energy based on hourly New England marginal clearing prices (billion $; $/MWh)		Mercury emissions (lbs)
Generic capital costs for expansion ($/kW)		Cooling water use (gal/minute)
Generic transmission expansion costs ($/scenario; $/MW-hour)		Amount of incremental land used (acres)
Generic distribution expansion costs ($/MW-hour)		Renewable energy contribution (MWh;% MWh)
Costs for generic expansion of gas-delivery system ($)		

(a) The systemwide production cost is the sum of the annual production costs (i.e., the fuel and emissions-related operating costs) for every resource to produce power in each hour of the simulated year.

(b) The annual revenue requirement (capital cost X the annual revenue requirement rate) captures all non-fuel-related costs including the recovery of capital costs, other operating costs, taxes, and other expenses.

3.3.1 Economic Metrics

The principal economic metrics can assist policy makers in evaluating the extent to which market-based electric energy revenues support investment in different technologies. The economic metrics also show the potential expenses LSEs have for wholesale purchases of electricity and include a comparison of the relative scenario expenses for electric energy, capacity, transmission, and distribution. Several of these metrics are explained further.

3.3.1.1 Annual Revenue Requirements for Expansion Resources

This metric is intended to indicate the extent to which the payments (or revenues) that a particular type of resource would derive from producing power in the wholesale electric energy spot market cover the expected investment cost associated with that technology. These investment costs include such things as taxes and fixed operations and maintenance costs. The greater the resource's wholesale electric energy market revenues compared with its production costs (i.e., the greater its net energy revenues), the more these revenues can help recover the resource's capital investment costs. Similarly, the narrower the gap between a power supplier's net energy revenue and the total of its fixed plus variable costs not captured in the simulation, the less "other revenues" it will need to stay in the market. "Other revenues" might include such things as payments from the Forward Capacity

Market (assumed for this analysis to clear within the range of $4.50 to $10.50/kW-month), the provision of ancillary services, tax benefits, sales of emission allowances, Renewable Energy Certificates, "clean" energy fund subsidies, or other monetary streams that value certain attributes of the power resources.[51,52]

As an example, the analysis showed whether a particular technology addition (e.g., the wind capacity added in Scenario #6) would produce power in a sufficient number of hours and at clearing prices necessary to generate revenues sufficient to cover overall capital and operating costs—or show a revenue gap that could be closed through one or more "other revenue" streams. This type of result would shed light on whether a particular technology path would likely induce its own type of technological investment or require additional policy support beyond that currently reflected in today's market and regulatory framework.

The annual revenue requirements for all the expansion resources were assumed to vary from 15 to 25% of the generic capital costs for the expansion technology. Annual revenue requirements for electric transmission and the natural gas system were assumed to be between 18 and 22% of the installed capacity costs. In the case of hydro and other imports, only generic transmission costs within New England and not those in Canada and New York were reflected in the analysis.

3.3.1.2 Marginal Clearing Prices and Load-Serving Entity Energy Expenses

In these analyses, marginal clearing prices reflect the annual average prices for wholesale electric energy in the New England wholesale energy markets. In each hour, the clearing price reflects the production costs of the last generating unit dispatched to meet load requirements in that hour. Clearing prices tend to rise during on-peak hours when generating units with higher production costs and lower efficiency are dispatched. Conversely, in the hours during which demand is the lowest (e.g., at night, or during weekends in the spring and fall), clearing prices may drop, reflecting the relative efficiency and lower fuel prices of the plants on the margin. The metric assumes that locational differences in marginal electric energy prices are nonexistent as a result of the expansion of the transmission system—the normal expansion as part of the annual regional system planning process and the generic transmission expansion assumed as part of the scenario analysis.

In New England's spot electric energy markets, load-serving entities pay (and generating units operating in that hour are paid) the clearing price in that hour.[53] When a generator is not on the margin, some of the payments made at the clearing prices may be higher than that generator's variable costs. These "net payments" contribute to covering a generator's other costs to own and operate the plant—costs that are not otherwise included in the production costs.

The metric for load-serving entity expenses reflects the total amount that buyers of wholesale electric energy, including utilities and competitive power marketers, would spend to procure this energy in New England's energy markets, if they bought all of their energy through the spot energy market.

[51] The Forward Capacity Market is a wholesale market designed by the six New England states and industry stakeholders to promote investment in supply and demand resources. Under the FCM, the ISO will project the needs of the power system three years in advance and then hold an annual auction to purchase the power resources that will satisfy the future regional requirements.

[52] A Renewable Energy Certificate represents the environmental attributes of one megawatt-hour of electricity from a certified renewable generation source for a specific state's RPSs. Providers of renewable energy are credited with RECs, which are sold or traded separately from the electric energy commodity.

[53] A *spot market* is market that typically involves short-term, often interruptible contracting and immediate delivery of specified volumes of electric energy, as opposed to bilateral trading. In New England, the Real-Time Energy Market is a spot market.

This is a proxy for costs to the buyer, recognizing that many buyers purchase electric energy through bilateral contracts rather than in the spot markets.

3.3.2 Reliability Metrics

Because the region currently relies heavily on natural gas to generate electricity, the addition of alternative resources will assist in diversifying the fuel supply. Reliability metrics were developed to assess the region's risk of exposure to disruptions of natural gas, oil, coal, and nuclear sources of energy. The reliability metrics include the amount of electric energy generated by each type of technology (MWh); the amount of generating capacity provided by the different technologies (MW); the units of fossil fuel required to be delivered into the region (MMBtu); and the amount of operable capacity available (or deficient) in the region, as an indication of the need for sources of power to mitigate potential fuel-supply disruption.

3.3.3 Environmental Metrics

For each scenario and sensitivity case, the environmental metrics include the total NO_X, SO_2, and CO_2 emissions and the total pounds of mercury emissions before applying extraction controls. The total regional NO_X emissions for the 10 highest demand days was also calculated. Other metrics that reflect various risks are also provided, as follows:

- Amount of fossil fuel used by resources within New England
- Extent to which the region's electricity supply is exposed to volatility in fossil fuel markets (principally gas and oil)
- Extent to which the scenario depends on the investment in and siting of energy delivery systems (for natural gas or electric transmission)
- Amount of water consumed for cooling power production at new generating facilities
- Percent of energy produced by renewable fuels

Recognizing the inherent limitations of an analysis like this, all the metrics are tied—directly and indirectly—to the performance of the electric power system compared with larger societal issues. Other large and small, important and unidentified benefits and costs of the different scenarios' externalities may exist that are not reflected in these metrics. These could include job creation, tax implications, public health and safety, siting and NIMBY (not-in-my-backyard) issues, life-cycle environmental impacts, and others.

Section 4
The Scenarios and Sensitivities

This chapter provides more details about the core technology reflected in each scenario and the sensitivity analyses that apply to each. It describes the basic technologies, their key features and attributes, and the technological assumptions used in modeling each scenario.

4.1 Scenario #1—The "Queue" Mix

This scenario portrays the conditions that might apply beyond the 2020 to 2025 time frame if "more of the same" type of resources that are currently responding to market signals in New England were implemented in larger quantities at that future time. In this scenario, a full 8,000 MW of capacity would be added on the basis of the types and amount of generating resources reflected in the ISO's Generator Interconnection Queue as of September 30, 2006. As shown previously in Figure 2, this mix includes fast-start, gas-fired "peaking" (CT) units; renewable power plants (composed of biomass, landfill gas, wind, fuel cells, and hydro projects); and coal-fired IGCC capacity.[54,55] In Scenario #1, all 8,000 MW are made up of this mix, unlike the other scenarios that include just 2,600 MW of this mix.

Scenario #1 has also been analyzed using the base-case fuel price, capital investment costs, and technology assumptions, as shown in Table 1. The heat rates, emission rates, and fuel costs for the different technologies in the queue vary widely. As shown in Table 2, these systems are assumed to have relatively high availability, except for wind, a resource with a limited inherent availability and no heat rates. Natural gas technologies, including fuel cells, have the highest conversion efficiencies; LFG, biomass, and IGCC technologies have somewhat lower efficiencies.

As with Scenarios #3, #4, #5, and #6 (see the following sections), this scenario requires an additional $60 million to $1.8 billion investment in the transmission system to accommodate the addition of the central station generators that use natural gas and coal as fuels as well as the expansion of wind resources. This scenario requires no new investment in regional natural gas infrastructure. All the sensitivity analyses, except the specialized cases, have been performed on this scenario.

4.2 Scenario #2—Demand-Side Resources

On top of the core assumption of 2,600 MW of capacity additions from the queue mix that all scenarios will add, this scenario incorporates a significant, 5,400 MW investment in demand-side resources, including energy-efficiency measures, technologies that shift demand from on-peak to off-peak hours, and measures that send price signals to customers to curtail their use in certain high peak-demand periods. It is presumed to be a mix of technologies.

[54] For Scenario #1, the incremental gas demands associated with these "queued-mix" gas-fired resources are assumed to be satisfied by the Canaport LNG facility. In addition, it was assumed that all dual-fuel combustion turbines within the "queue-mix" would run on oil rather than natural gas during the core heating season, November through March, thus obviating the need for pipeline improvements to serve these new peaking generators.[assumption]

[55] *Fast-start* resources can start up and synchronize to the system in less than 30 minutes. They help with recovery from contingencies and assist in serving peak load.

Scenario #2 has been analyzed using the base-case fuel price and demand-side assumptions discussed in Section 2. The demand-side energy-efficiency resources in this scenario reflect annualized costs in the range of $110 to $400/kW-year. These convert to capital investment costs that range from $920 to 3,300/kW. Demand-response reflects annualized costs ranging from $10 to $30/kW-year. Demand-side resources were assumed to produce no emissions. Although some technologies can have emission rates, these were not modeled in this scenario. It was assumed this scenario would not require expansion of the electric transmission system beyond RSP projects and these demand-side reductions would lower the future amounts of distribution infrastructure needed for the other scenarios, from $100 million to $325 million.

Scenario #2 has been examined with the robust set of sensitivity cases described previously in Table 5. For the retirement case, a total of 2,600 MW of new power production capacity and 8,900 MW of demand-side resources were added, while 3,500 MW of older capacity was removed.

4.3 Scenario #3—Expansion of Nuclear Plant Capacity

This scenario assumes the common-assumption addition of 5,400 MW of nuclear capacity, located at or near existing nuclear stations requiring $60 million to $1.8 billion in new transmission investment to interconnect the nuclear facilities to the grid. Similarly, this scenario requires no new investment in regional natural gas delivery infrastructure. Additionally, like all other core scenarios, Scenario #3 assumes the addition of 2,600 MW of capacity additions from the queue mix.

The nuclear expansion case assumes the following:

- A base-case fuel price of $17/MWh (which includes maintenance and waste disposal)
- 10,000 Btu/kWh heat rate (midrange efficiency)
- 90% availability factor
- Capital costs ranging from $3,000/MW to $5,000/kW
- Zero emissions of air pollutants from the plant

All non-production-related costs are captured in the annual revenue requirements range of 15% to 25%. Scenario #3 has been analyzed using the full set of sensitivity analyses shown in Table 5.

Because of the low production costs and zero emissions of this scenario, the IREMM simulation results for this scenario might also represent the combined effects of energy-efficiency technologies that could always be present in a constant continuous amount, such as a refrigerator (as compared with an air conditioner) similar to a baseload generator.

4.4 Scenario #4—New Coal-Fired Power Plants Using Integrated Gasification Combined-Cycle Technology

This scenario involves adding IGCC generating capacity. This technology has been considered in two ways: one, without investment or operating costs associated with capturing the CO_2 as a separate, add-on module after the coal-gasification process; and another, involving investment to capture and then transport and sequester (permanently store) the CO_2. The IGCC operating and capital cost and efficiency penalties associated with the carbon capture, are shown in Table 1. The carbon-capture and storage version of IGCC releases only 10% of the CO_2 emissions to the atmosphere with compared with the version without capture.

Capital costs for IGCC without CO_2 capture at the plant are assumed to fall in the range of $2,500/kW to $3,500/kW; by contrast, the capital costs are $400/kW higher for adding a plant module for carbon capture. Additional costs would be associated with the transportation and storage (i.e., the sequestration of the CO_2 itself).

This scenario is assumed to not require additional regional natural gas delivery infrastructure but will require $61 million to $1.8 billion for electric transmission expansion. All the general sensitivity cases, as well as the carbon sequestration case were run as shown in Table 5.

4.5 Scenario #5—New Gas-Fired Combined-Cycle Power Plants

This scenario adds 5,400 MW of the natural-gas-fired CC technology that dominated the generating capacity additions during the 1995 to 2005 period in New England (and elsewhere in the United States). This scenario also adds 2,600 MW of the capacity from the queue mix, which also includes some NGCC capacity as well.

This scenario assumes that the capital costs for combined-cycle plants ($800/kW to $1,000/kW) and their heat rates (6,500 Btu/KWh) are relatively low compared with other fossil fuel units. Similarly, the air pollution emissions rates for these plants are relatively low. Gas prices, by contrast, are assumed to be relatively high compared with prices for other fuels, even in the base-case fuel-price forecast. The operating costs of these plants are directly tied to regional natural gas prices.

This scenario is assumed to require significant expansion to the natural gas delivery infrastructure, ranging in an incremental cost from $150 million to $1.5 billion. This reflects a combination of projects involving, for example, gas pipeline expansions, additional liquified natural gas import terminals, and regasification facilities. For the retirement sensitivity scenario, the amount of conceptual investment in incremental natural gas infrastructure would increase to $400 million to $3 billion. This scenario would require electric transmission expansion that would cost $61 million to $288 million.

Scenario #5 has been analyzed with all but the specialized sensitivity cases.

4.6 Scenario #6—New Renewable Projects

This scenario involves a combination of various renewable resources projects:

- Offshore wind
- Inland onshore wind
- Biomass
- Fuel cells

- Landfill gas
- Combined heat and power systems
- Solar photovoltaic technologies
- Hydroelectricity

The total capacity involved in this scenario is designed to be equivalent to the 5,400 MW of capacity included in the other scenarios, with one-eighth of this amount of equivalent capacity coming from each of these renewable technology types. This scenario also adds 2,600 MW of capacity from the queue mix, some of which also includes other renewable resources (i.e., wind, hydro, fuel cells, biomass and LFG capacity) (see Figure 2).

This scenario involves adding resources with capital costs ranging widely from $1,000/kW to $6,000/kW (on a nameplate capacity basis), as shown on Table 2, for landfill gas, biomass, fuel cell, wind, and CHP capacity. The wind, solar, and hydro resources have no air emissions, and the other technologies have low emissions. (see Table 3). Some resources (e.g., onshore and offshore wind and solar PV systems) have no fuel costs or air emissions; others have air emissions and relatively poor heat rates. Two technologies, CHP and fuel cells, have exhaust heat which can serve an on-site energy demand for process heat, hot water, steam, or other uses.

This scenario does not assume the need to expand the regional natural gas distribution systems to provide incremental gas for the fuel cells and the CHP systems. However, if gas LDC expansion were required, that expansion would be undertaken with sufficient compensation under rates(s) charged by the LDCs for transport services, with an associated delivery and distribution charge in the range of $0.195/therm to $.445/therm.[56] [57] Additionally, the onshore and offshore wind resources are assumed to require additional electric transmission facilities costing in the range of $581 million to $3.9 billion. Scenario #6 has been analyzed with the full set of general sensitivity cases. For the retirement case, 8,900 MW of the new resources are renewable resources.

4.7 Scenario #7—Increased Imports of Hydroelectricity and Other Low-Emission Resources

This final scenario involves the construction and operation of a new major transmission system into New England to provide the capability to import 30 million MWh of power on a firm basis from neighboring regions with a profile of up to 5,400 MW during high-load periods. This scenario, like the others, includes the addition of 2,600 MW of capacity from the queue mix. This scenario estimated conceptual transmission-cost estimates to import power from Canada, New York, or both. The conceptual transmission cost estimates were developed to the New England–Quebec border and the New England–New Brunswick border to the north and the New England–New York border to the west. These conceptual capital costs range from $3.1 to $8.9 billion for the New England–Canadian

[56] One therm of natural gas is equivalent to 100,000 British thermal units (Btu), which is roughly equivalent to the heat content of 100 cubic feet of natural gas.

[57] On top of these LDC distribution charges, the gas shippers (for fuel cells and CHP systems) would also need to pay the commodity cost of gas, pipeline transportation charges, fees for imbalance resolution, and an allowance for lost and unaccounted for gas.

routes, and $1.0 to $2.4 billion to the New York border. As with other scenarios, these estimates were based on an analysis that examined a range of generic transmission costs.

This scenario also assumes that the power imported into the region will be from a low-emitting power source, such as hydroelectric power, wind, or nuclear power, and that these resources will not contribute air emissions. The model dispatched these resources to serve peak demand periods and had other underlying assumptions for costs, including the need for transmission expansion. The commercial terms of any agreement to import power from a neighboring region would likely differ from the assumptions made in Scenario Analysis.

Scenario #7 analyzed the full set of general sensitivity cases. Under the assumption that demand-side resources totaling 3,500 MW would replace import capacity, the import capacity for the sensitivity case would reduce from 5,400 MW to 1,900 MW, the energy transferred to New England would reduce from 30 million MWh to 11 million MWh, and the amount of generic costs for transmission expansion would be halved. The retirement sensitivity case retired 3,500 MW of existing generating units (as of 2007), replacing them with an equivalent amount of additional imported energy and capacity (20 million MWh and 3,500 MW more, respectively). This case also assumed that the transmission facilities necessary to import the additional 3,500 MW of power would need additional expansion. The low-import sensitivity case imported only 23 million MWh, rather than 30 million MWh, via the new tie line but with the same capacity cost for the transmission line.

It was assumed that the neighboring regions would pay the capital costs of the expansion resources. While conceptual transmission cost estimates have been developed for neighboring systems, the economic analysis in this report only considers generic transmission costs within New England. This simplifying assumption was made because too many factors are unknown. For example, building or advancing the in-service dates of new facilities for New England's use is potentially needed as opposed to improving the use of facilities that may be planned solely for use by neighboring systems. Costs could vary widely.

Section 5
Results and Observations

This section summarizes the key economic, reliability, and environmental results for each scenario and compares the results for the common set of assumptions with the results for the sensitivity cases. Detailed and summary tables and charts showing additional results and comparisons are available on the ISO's Web site.

These results are intended to inform future discussions about different public policies that can be pursued if a particular technology path or several paths hold particular interest or value for the region. The ISO encourages interested parties to compare the results for the different scenarios and reach their own conclusions about the various technology paths.

5.1 Economic Results

Several key economic metrics were analyzed for the different scenarios and sensitivity analyses, including production costs, average clearing prices, load-serving entity costs, and annual comparisons of the annual net energy revenues minus the annual revenue requirement for new resources. The scenarios differed considerably across these economic metrics. Table 7 summarizes the annual production and wholesale electric energy market costs and average marginal clearing prices for Scenario #1 (the queue) under the common set of assumptions and the double energy-efficiency case. It also compare these costs with the costs for the other scenarios. These results are discussed in subsections that follow.

Table 7
Annual Production and Wholesale Electric Energy Market Costs and Average Marginal Clearing Prices for the Scenarios Compared with the Queue Case under the Common Assumptions

	Prod. Cost ($ mil)	Change from Queue ($ mil)[(a)]	% Change from Queue	Avg. Marginal Clearing Price ($/MWh)	Change from Queue ($/MWh)[(a)]	% Change from Queue[(a)]	Annual Wholesale Electric Energy Market Cost to LSEs ($ mil)	Change from Queue ($ mil)[(a)]	% Change from Queue[(a)]
1. Queue	6,833	-		69	-		11,997	-	
2. EE/DR[(b)]	6,298	535	7.8	70	–1	–1.4	12,235	–238	–2.0
3. Nuclear	5,502	1,331	19.5	61	8	11.6	10,566	1,431	11.9
4. IGCC	6,525	308	4.5	63	6	8.7	10,895	1,102	09.2
5. NGCC	6,825	8	0.1	62	7	10.1	10,796	1,201	010.0
6. Renewables	5,569	1,264	18.5	60	9	13.0	10,344	1,653	013.8
7. Imports	5,522	1,311	19.2	64	5	7.2	11,085	912	7.6
All EE[(b)]	**5,148**	**1,685**	**24.7**	**62**	**7**	**10.1**	**10,811**	**1,186**	**9.9**

(a)"+" = cost savings; "–" = more costly

(b) Rather than being modeled as a reduction to the load curve, energy-efficiency and demand-response resources are modeled in this analysis like supply-side resources. Energy efficiency and demand response are modeled as if they offered "energy" at no cost to the system, and the party that invested in these measures was paid the calculated net energy revenues, which is equivalent to the dollar savings in reduced energy consumption from those resources. The energy efficiency and demand response scenario is assumed to supply 18 Million MWH of no-cost "energy," and the all-energy-efficiency case is assumed to provide 36 million MWh of no-cost "energy," which is comparable to the nuclear and IGCC scenarios.

5.1.1 Production Costs

As shown in Table 7, under the common set of assumptions, the seven scenarios have production costs ranging from a low of approximately $5.5 billion (Scenarios #3, nuclear; #6, renewables; and #7, imports), to a high of almost $7 billion for Scenario #1 (the queue) and Scenario #5 (NGCC). In these analyses, production costs largely reflect fuel-related costs, including emissions allowances, to run the entire New England-wide bulk electric power system. Across the scenarios, the annual systemwide electric-energy-related production costs range from a low of less than $4 billion (Scenario #7, imports) in the low-gas-price sensitivity case to a high of approximately $10.5 billion (Scenario #5, NGCC) in the high-gas-price case.

Improvement in overall system efficiency is evident in all cases as shown by systemwide production costs that are lower than these costs for Scenario #1 (the queue). In Scenario #2 (demand-side resources) energy efficiency provides 18 million MWh of energy at no production cost, resulting in a systemwide production cost of $6.3 billion. While Scenario #2 shows high production costs relative to the other scenarios, because half of the capacity is from peak-shaving demand-response, the sensitivity case that assumes doubling energy efficiency (with no demand-response) shows production costs decreasing. These costs become the lowest ($5.1 billion) among the seven scenarios under the common set of assumptions.

The results show that the sensitivity cases that retire older generating units lead to reduced production costs relative to the simulations under the common set of assumptions. The sensitivity cases with high carbon-allowance prices tend to increase production costs compared with the scenarios under the common assumptions.

5.1.2 Average Clearing Prices

Figure 3 shows the patterns of average marginal clearing prices across all the scenarios and sensitivity cases. Table 7 shows the average marginal clearing prices for just the scenarios under the common set of assumptions. These results show the effect of either changing the resource mix or changing input costs on the average cost of electric energy.

Generally, the average marginal clearing prices for the cases under the common set of assumptions range from $60 to $70, as shown in Table 7. This range is relatively small compared with the differences in the patterns across the sensitivity cases. For example, the results for the sensitivity cases with low and high gas prices vary by approximately $60 across all technologies. The greatest change in wholesale electric energy costs results from changes in fuel prices, which suggests that the key driver of average clearing prices is the gas-price assumption. This is because gas-fired power plants tend to be marginal generators and set the average clearing prices across all scenarios. As an example, gas units are on the margin for approximately 90% of the hours in all common-assumption scenarios, as shown in Figure 4.

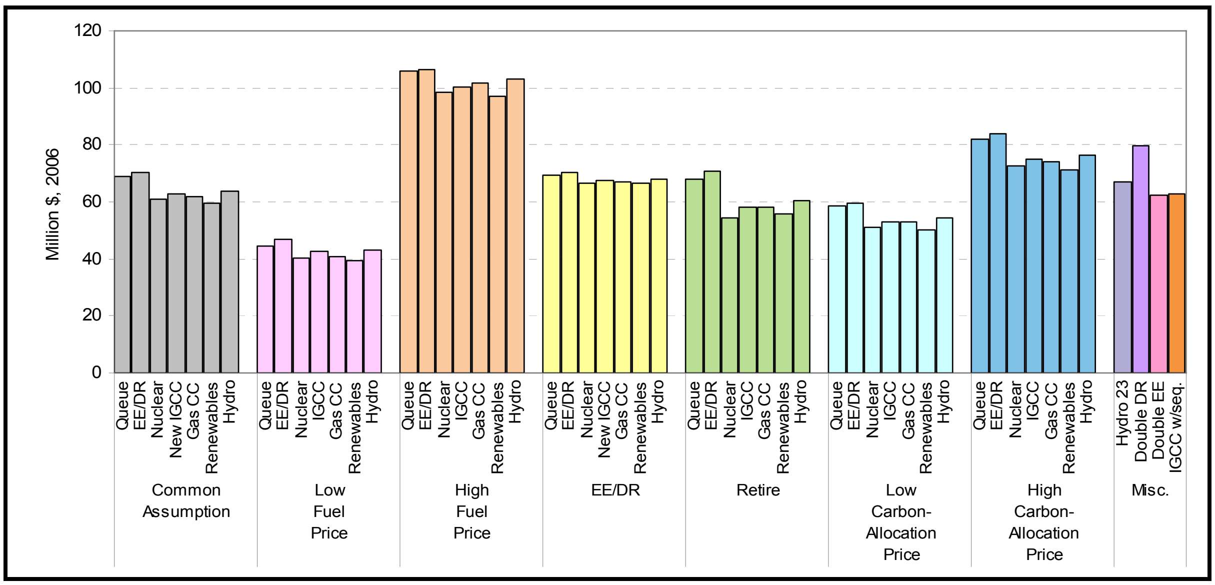

Figure 3: Average clearing price for wholesale electric energy, grouped by sensitivity case, $/MWh.

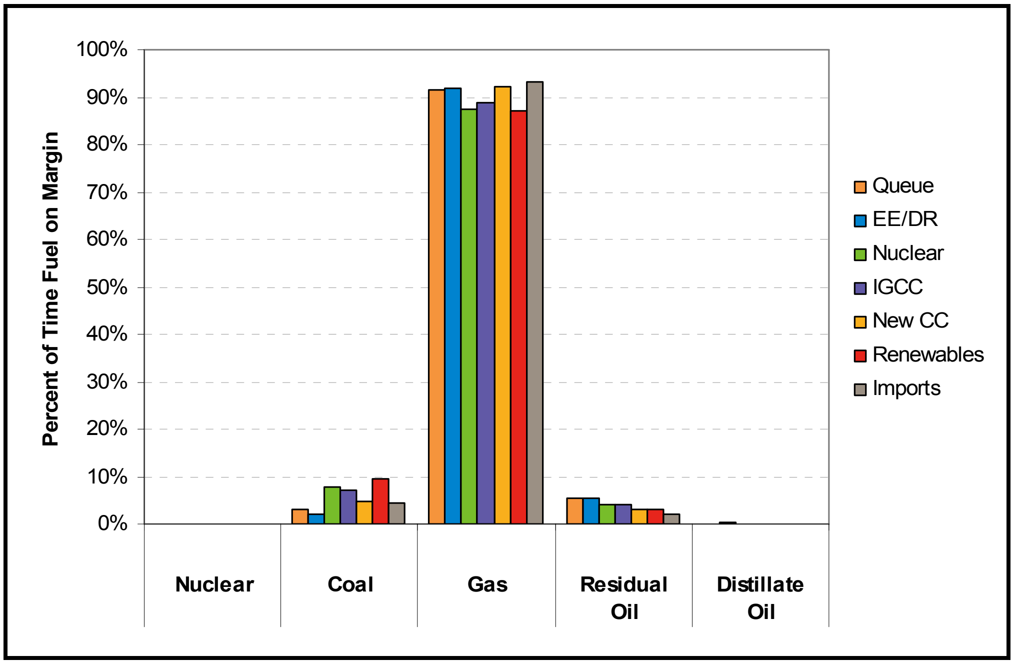

Figure 4: Percent of time fuel is on the margin.

The addition of regional natural gas supply and delivery system infrastructure and reductions in gas-sector demands could mitigate prices during periods of high demand. Several demand-side technologies could provide dual benefits of reducing demands of both natural gas and electrical energy (e.g. efficient gas-fired heating systems, improved home insulation, HVAC environmental controls, and other measures), which could reduce the price of both natural gas and electricity.

5.1.3 Annual Wholesale Electric Energy Market Costs

The annual wholesale electric energy market cost represents the total electric energy cost to load-serving entities. It is equivalent to the total electric energy revenues that resources receive for supplying electric energy, including demand-side resources and imports from neighboring systems, to the wholesale market.

Figure 5 shows the results for annual wholesale electric energy expenses (million $, 2006) across all 53 simulations, grouped by sensitivity case. Across the scenarios and on a New England-wide basis, load-serving entity expenses for electric energy range from about $10.5 to about $12 billion under the common set of assumptions. At the lower end of the range are Scenarios #3 and $6 (nuclear and renewables) and Scenario #2 (all-energy-efficiency adjusted with energy efficiency replacing demand response). At the higher end of the range are Scenario #1 (the queue) and Scenario #2 (demand-side resources), especially the sensitivity case with all demand response.

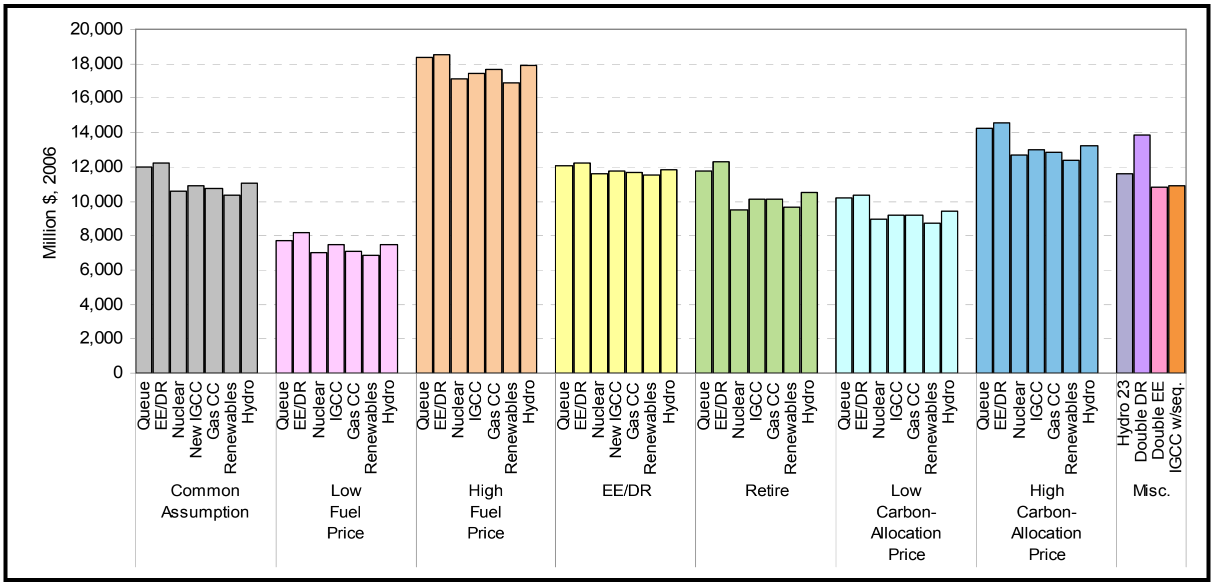

Figure 5: Load-serving entity annual expense for wholesale electric energy, grouped by sensitivity case, millions of 2006 dollars

Load-serving entity costs rise dramatically in the cases where natural gas prices are assumed to rise, with expenses totaling from approximately $16+ to about $18+ billion across the scenarios. Conversely, payments drop in the low-fuel-price cases, ranging from approximately $6.5 billion to about $8.0+ billion. Across the various sensitivity simulations, Scenarios #3 and #6 (nuclear and renewables) tend to have the lowest costs for electric energy, and Scenarios #1 and #2 (the queue and demand-response cases) tend to have costs at the higher end.

Table 7 (shown previously) compares the total annual wholesale electric energy market costs for the scenarios under the common set of assumptions. In this analysis, annual wholesale electric energy market costs correlate directly with the average marginal clearing price level. In general, buyers of wholesale electric energy (load-serving entities) face the lowest prices when gas prices are low and the highest prices when gas prices are high, regardless of the scenario examined. Like average clearing prices, these annual wholesale energy market costs are largely shaped by the assumptions about the future price of natural gas. If gas prices are high, prices will tend to support more of the capital investment needed to pay for non-gas technologies (as well as gas-fired technologies). Refer to Figure 5.

5.1.4 Comparison of Net Energy Revenues and Annual Revenue Requirements

Figure 6 summarizes and compares the total annual costs of the scenario technologies. These costs include the net revenues to resources from the wholesale electric energy market and revenues from the capacity market. The figure also shows the annual revenue requirements of the scenario technologies and the associated electric transmission and natural gas system expansion requirements. Results are shown for both high and low assumptions to reflect the uncertainty in these revenue streams and cost estimates. The figure shows the net revenue needed from the wholesale electric energy market to in turn ensure the economic efficiency of resources needed to reliably provide energy to load.[58] The results also show the need for other revenue streams, after including those from the capacity market, to support investment in most of the technologies examined.

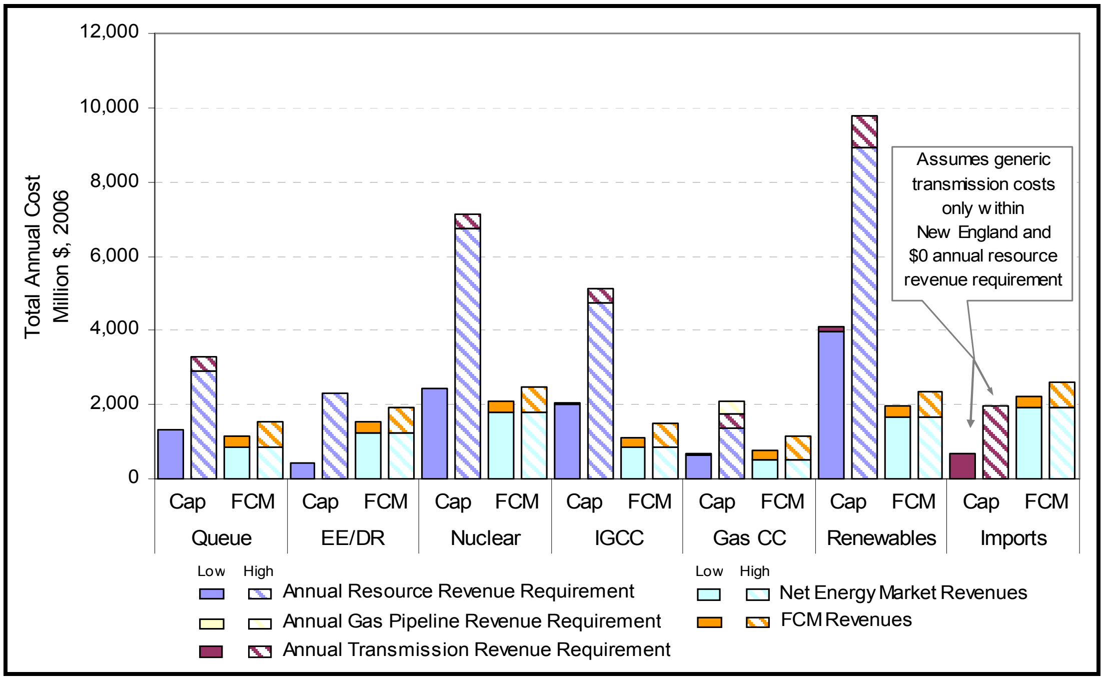

Figure 6: High and low caps for resource, gas pipeline, and transmission revenue requirements compared with FCM and net energy market revenues for scenario technologies under the common set of assumptions.

The various technologies have different abilities to recover their capital and other costs for providing electric energy, in large part depending on the assumptions about fuel prices. Sources of revenue other than the wholesale energy markets include revenues from capacity markets and ancillary services, as well as state and federal tax incentives, sales of emission allowances, Renewable Energy Certificates, and other sources. For example, many technologies (including energy efficiency, small hydro, biomass, IGCC, wind, nuclear, landfill gas, and hydro imports) come close to supporting the annual revenue requirements at the low end of cost ranges under the high-fuel-price scenarios only. The gap between net electric energy market revenues and annual revenue requirements is large for all technologies except energy efficiency, demand response, and imports from neighboring systems, but the latter assumes no resource capacity costs and no transmission costs outside New England. Energy efficiency nearly covers its annual revenue requirements and falls in the middle of the range of capital costs.

Demand response provides electric energy revenues that are associated with financial incentives (on a dollar-per-kilowatt-year basis) to induce electricity users to curtail their demand during peak periods. After energy efficiency and demand response, which appear to be able to cover annual revenue requirements through electric energy market "revenues" (savings), the other technologies that come closest to covering these revenue requirements are NGCC and imported hydro. Biomass, small hydro, and nuclear technologies have wider margins between annual revenue requirements and electric

[58] The net electric energy market revenues to resources equals the gross wholesale electric energy revenues minus the production costs, which include variable fuel and environmental emission costs.

energy revenues, but their low operating costs compared with their relatively high electric energy production costs provide them with a significant capital contribution from the electric energy markets—although not sufficient enough to reach the midrange of the annual revenue requirements.

Other technologies tend to have a significant gap between net revenues and capital costs, whether at the low or high end of the capital cost range. Assuming base-case fuel and allowance prices, the gap between net revenues and capital costs is relatively large for PV systems, IGCC (with or without carbon sequestration), and offshore and onshore wind.

Notably, two technologies (CHP and fuel cells), which are part of Scenario #6 (renewables), show negative electric energy market revenues in this analysis. These results stem from a modeling representation that did not include the collateral energy benefits of using the steam loads (waste heat) that fuel cells and CHP provide to the facilities where they are installed. They also do not capture other benefits, such as not needing diesel backup electric systems and corresponding air permits. This caused them to operate on a nondispatchable basis usually at a customers' site behind the meter. This was modeled but without any offsets for the waste-heat fuel-efficiency benefits these technologies provide. In this analysis, fuel cells run on natural gas as baseload and are expensive such that they need financial subsidies for many applications. Without considering the use of the waste heat that these technologies provide, no real observations can be made about these economic results of the Scenario Analysis.

Queue capital costs seem to be most similar to gas-fired capital costs. This is not surprising, as new gas units appear to be most economic.

5.2 Reliability Results

The following highlights address the energy mix, fuel-use patterns, and operable capacity analysis.

5.2.1 Energy Mix and Fuel-Use Patterns

The following discussion focuses on the production of electricity and the amount of fuel used from various types of resources necessary to meet the overall systemwide energy needs of approximately 174 million MWh (174 TWh).

5.2.1.1 Natural Gas Use and Power Production

The use of natural gas for electric power production varies substantially across the sensitivity cases, as a result of various factors. Under the common set of assumptions for the seven scenarios, electric energy produced from NGCC power plants ranges from a low of about 55 million MWh (in Scenario #3, nuclear), to a high of about 97 million MWh (in Scenario #5, NGCC). The use of natural gas also is relatively high in Scenario #1 (the queue), which produces approximately 83 million MWh, and in Scenario #2 (demand-side resources), which results in the use of 76 million MWh of natural gas. In Scenario #2, demand response provides half of the capacity expansion, which does not provide any significant amount of electric energy and thus causes existing gas-fired generation to operate more often than in many other cases. Compared with the scenarios under the common set of assumptions, the sensitivity analyses produce varying amounts of gas-fired electric generation, as follows:

- When natural gas prices are assumed to be high, gas use tends to drop by roughly one-third compared with the use of gas in each of the scenarios under the common set of assumptions.

When natural gas prices are assumed to be low, gas use increases by roughly 10 to 20%, relative to gas use in each initial scenario.

- In the sensitivity cases assuming the replacement of supply-side technology with greater demand-side resources, the use of gas rises relative to the original scenarios. This is in large part because, like under the common set of assumptions, demand response does not introduce much energy-producing capacity into the overall capacity expansion plan. Therefore, generation at fossil-based production facilities rises even though energy efficiency produces energy savings.

- Where older power plants are assumed to retire, the use of natural gas is similar to the level in the scenarios under the common set of assumptions, except in the case where more gas-fired plants are assumed to replace retired capacity.

- The use of natural gas use tends to increase in the sensitivity case with high carbon-allowances prices. Gas use declines when energy efficiency is doubled. The most gas is used in the cases where gas prices are low.

- Electricity production from gas-fired peaking units doubles and in some case triples relative to the common set of assumptions; where gas-peaking capacity is added (in Scenario #1); where carbon prices are high, which causes gas use in peaking units to rise by about 50%; and where demand response is doubled (again, since demand-response is only peak-shaving and does not add much energy-producing or energy-saving resources). The use of peaking units to produce large quantities of electric energy, which they were not designed for, also increases electric energy prices.

5.2.1.2 Oil Use and Power Production

Oil use for power production does not vary significantly across the scenarios and sensitivity cases:

- Residual fuel oil (heavy fuel oil)—Across almost all the cases analyzed, except Scenario #2 (demand-side), residual fuel oil is used minimally in New England; just under one-half million MWh of electricity is generated by heavy fuel oil. The main exceptions are cases where the oldest generating units in the region are assumed to retire, which causes power production by residual oil to be virtually eliminated, or where gas prices are assumed to be higher and to move significantly above heavy oil prices. This shows the use of residual oil rising to about 100 times the base case, 33 million MWh, depending on the scenario or sensitivity case.

- Distillate fuel oil (light fuel oil)—The use of light oil in peaking units is relatively constant across the cases (about 40,000 MWh), except in two sets of circumstances:

    - Where retirements of older plants are assumed to occur, which causes the increased use of oil-fired peaking units (producing about 57,000 MWh of output)

    - Where demand-response measures are adopted, for which the use of oil in peaking units rises considerably relative to other cases (about 85,000 MWh in Scenario #2 and to about 130,000 MWh in the sensitivity analysis where demand-response capacity is doubled)

These demand-response cases result from the assumption that when demand-response capacity is added for peak-shaving purposes, other capacity has not been added to supply compensatory energy production. As a result, a significant portion of the region's oil-fired peaking units remain in place and produce electricity more often than might otherwise be the case with the other scenarios that provide more electric energy at lower cost than these oil-fired units.

5.2.1.3 Coal Use and Power Production

Overall, the scenarios and sensitivity cases indicate that with a few exceptions, the use of coal in New England is relatively insensitive to the various capacity expansion scenarios showing a level of coal use at around 25 to 30 million MWh. The exceptions to this observation are as follows:

- Scenario #4 (IGCC) causes coal-fired power production to rise dramatically to around 63 million MWh—even higher when older power plants are assumed to retire and be replaced with coal capacity (about 76 million MWh).

- When natural gas prices are assumed to be relatively low, gas-fired power plants are dispatched more often and in some cases displace generation at existing coal-fired power plants (dropping coal production to about 9 to 15 million MWh, depending upon the scenario).

- For the high carbon-allowance price sensitivity case, coal-fired power production tends to decline by approximately 5 to 8 million MWh across the scenarios. Low carbon-allowance prices do not cause coal plants to operate substantially more than under the common set of assumptions.

5.2.1.4 Renewables Use and Power Production

The use of renewable resources for power production varies across the cases, largely in direct proportion to the assumptions in each scenario about the amount of renewable resource capacity added. For example, renewable power production is relatively insensitive to many assumptions about fuel prices and carbon prices, since in the Scenario Analysis exercise, the amount of renewables added to the system is predetermined for each case. That is, output at power plants using renewable resources (i.e., wind, hydro, PV) is not "dispatchable" in these analyses; rather, power production tends to occur when the resource is available (i.e., when the wind is blowing or when the sun in shining on PV systems). Once a given amount of capacity is available, it is assumed to provide power to its operational limits.

The case with the highest renewable power production is Scenario #6 (renewables), which produces approximately 47 million MWh of electricity. Approximately 20 million MWh of this electricity is from existing and new on- and offshore wind facilities, and about 22.5 million MWh is from other renewables, including fuel cells, hydro, biomass, PV, CHP, and landfill gas. In other scenarios, renewables produce about 13 million MWh of power.

5.2.1.5 Nuclear Use and Power Production

Overall, nuclear generation is relatively constant across the cases, with about 35 million MWh of output at existing nuclear plants in the region. The only exception is in Scenario #3, for which 5,400 MW of new nuclear generating capacity would be installed. In this case, nuclear output rises to about 78 million MWh (and to about 105 million MWh in the case where the oldest generators in the region retire and are replaced with new nuclear capacity).

As a result of the relatively large and inexpensive energy production and zero emissions associated with the nuclear expansion scenarios, total systemwide emissions are also significantly reduced. These simulation results can also represent the impact of baseload energy-efficiency technologies.

5.2.1.6 Energy Efficiency Use and Power Production

Because energy efficiency is input directly into the model as a load modifier, the results of the analyses do not show variations in energy-efficiency "production" associated with fuel prices or carbon-allowance prices. By modeling energy efficiency and demand response in the same way as supply-side resources, which was an attempt to treat supply-side and demand-side resources in a comparable way, the Scenario Analysis does not capture the expectation that, in reality, energy efficiency and demand response are actually deployed in ways that represent a net reduction in electric energy use at any point in time. As a result, and all else being equal, in any particular hour in which the demand-side resources are in place, the overall load will go down compared with a situation in which that demand-side resource were not available.

As assumed, energy-efficiency measures save a relatively significant amount of energy (18 million MWh) across the cases. In the sensitivity cases where the energy efficiency is doubled, this "technology" produces 35 million MWh of "savings." Where the older generating units are retired and replaced with energy-efficiency measures and demand response, the amount of energy "provided" by energy efficiency rises to 30 million MWh. The cases show that increased supply of energy from relatively inexpensive sources tends to decrease electric energy prices as a result of the displacement of natural gas and oil-fired units.

5.2.2 Operable Capacity Analysis Results

Using a methodology similar to RSP06, the operable capacity analysis (OCA) was conducted to evaluate the ability of the system to reliably serve seasonable peak demand during periods of disruption to specific types of fuel. The OCA results demonstrate continued dependence upon gas-fired generation across all scenarios. The results show a need for additional dual-fuel capability for single-fuel gas plants, firm gas supply and delivery contracts, and additional gas-side infrastructure expansion (i.e. gas pipeline enhancements and incremental LNG supply to reduce exposure to reliability issues that could arise from short-term interruptions in domestic or international natural gas supply). For example, approximately 18,100 MW of natural gas units would need to be available to avoid the use of emergency procedures over the summer peak period. Approximately 11,400 MW of natural gas units with uninterruptible fuel supply are needed in winter to avoid the use of emergency procedures.

The OCA results also show an increased reliance on other expansion technologies, such as nuclear, coal, and oil. For these cases, the increased diversity of fuel suppliers (e.g. different sources of imported coal) or the ability to access or import additional resources, possibly from neighboring systems, could mitigate the exposure to fuel-supply disruptions. The extent of exposure to simultaneous outages of nuclear plants could also be mitigated by coordinating maintenance outages. These OCA results are shown in Figure 7 for both the summer and the winter operating seasons. The dependence on fuel supply (measured in MW) shows the amount of capacity that would be required to meet peak loads during a particular type of fuel disruption (e.g. gas for the NGCC scenario, nuclear for the nuclear scenario, etc.) and can be viewed as a risk management tool. A high dependence indicates the need to gain access to resources with alternate fuels or find some other means to reduce exposure to fuel disruptions.

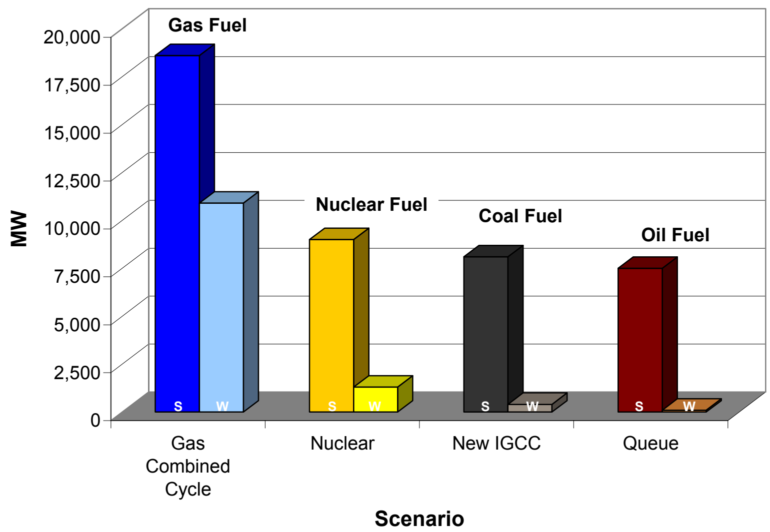

Figure 7: Summer (S) and winter (W) operable capacity needed by fuel source, MW.

5.3 Environmental Results

A number of metrics were analyzed for the environmental impacts associated with the different scenarios. This comparative discussion focuses on air emissions, although a few other environmental impacts are also discussed.

5.3.1 Air Emissions

The levels of SO_2, NO_X, CO_2, and Hg emissions associated with the different scenarios are directly tied to the type and amount of fossil fuel used to generate electricity for the different cases analyzed.

5.3.1.1 Sulfur Dioxide Emissions

Figure 8 shows total annual SO_2 emissions (million tons) for each of the scenarios, grouped by sensitivity case. The results show that SO_2 emissions, which primarily are driven by the addition of coal in the region's energy supply mix, are highest for Scenario #4 (IGCC). SO_2 emissions are highest in absolute terms when gas prices are high and gas plants are not run as often as they are under either the common set of assumptions or the low-gas-price assumptions. In fact, SO_2 emissions approximately double in the high-gas-price case relative to the common set of assumptions. SO_2 emissions increase from the low-gas-price sensitivity case to the high-gas-price case by over 100,000 tons for all expansion scenarios. SO_2 emissions drop in the retirement cases, where older plants, many of which burn coal and heavy oil, are retired and replaced with newer and—in most scenarios—lower-emitting power plants.

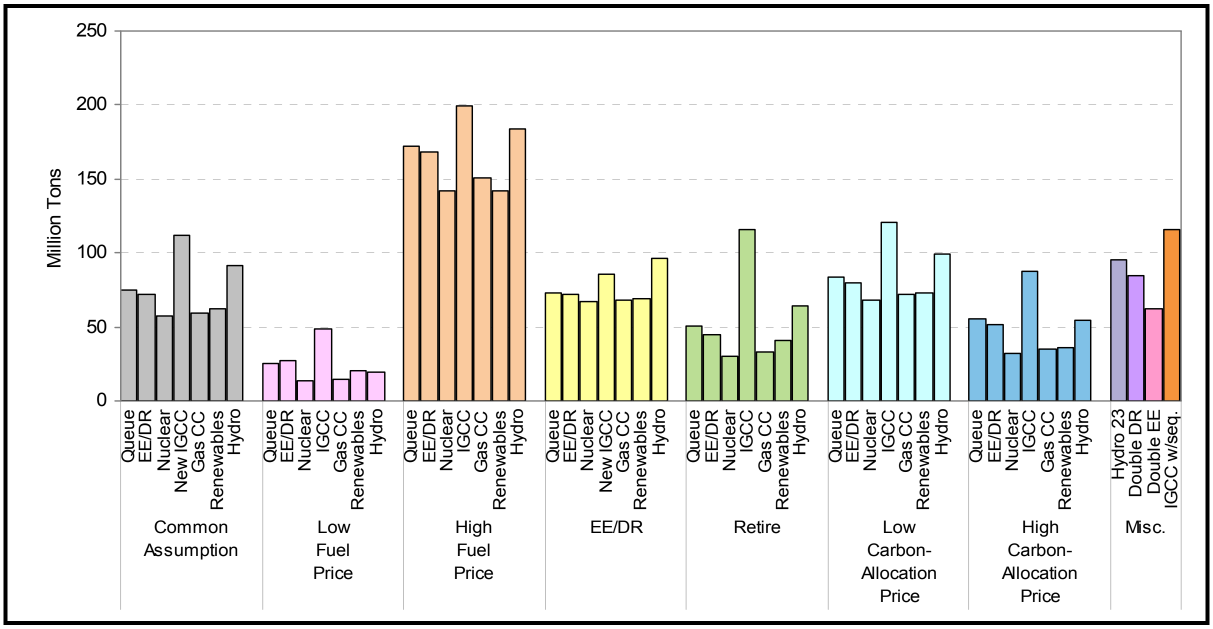

Figure 8: Total annual SO_2 emissions, grouped by sensitivity, thousand tons.

5.3.1.2 Nitrogen Oxides Emissions

Figure 9 shows that total annual NO_X emissions (million tons) follow a somewhat parallel pattern as those for SO_2. Total annual NO_X emissions are significantly higher in general when gas prices are high relative to oil, because gas-fired power plants, which have lower NO_X emissions rates than oil plants, operate less often than in other cases. Conversely, NO_X emissions are significantly lower when gas prices are low and in the cases where older generating units are retired and replaced with newer, more efficient power plants that have lower NO_X emissions rates.

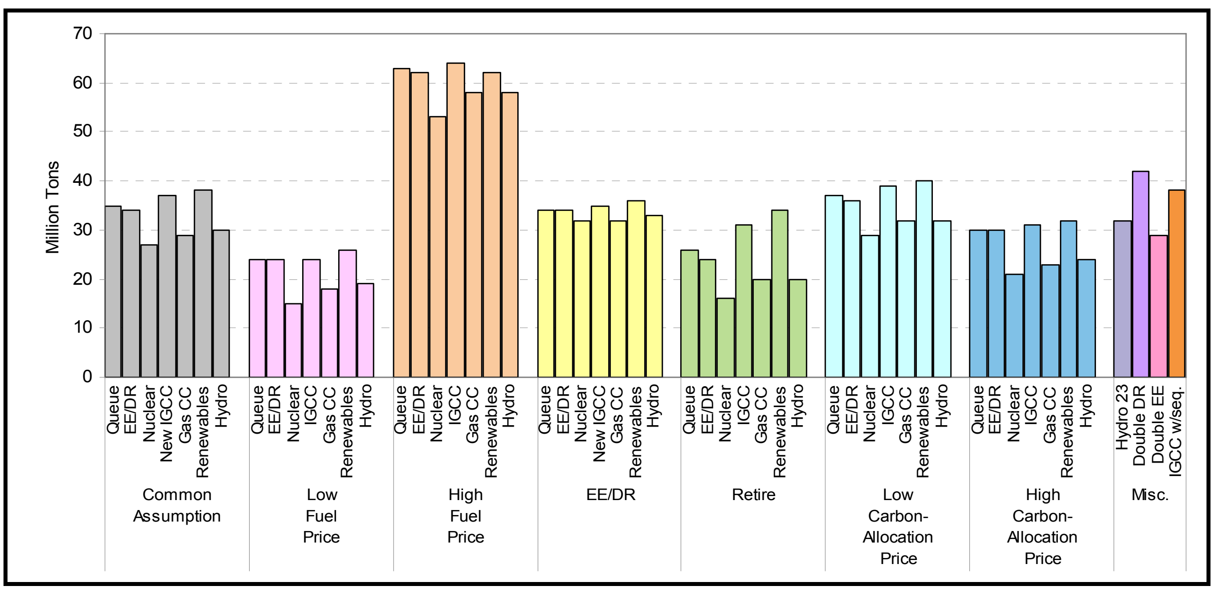

Figure 9: Total annual NO_X emissions, grouped by sensitivity, thousand tons.

Also of particular interest are the top 10 daily emissions of NO_X. The scenarios and sensitivity cases were examined by tracking the amount of NO_X emissions produced on the days that had the 10 highest NO_X emissions. Emissions tended to be lowest in the scenarios with capacity additions that reflect low-emitting/high-energy-producing capacity, such as Scenario #3 (nuclear), Scenario #5 (NGCC), and Scenario #7 (imports). Scenario #2 (energy efficiency and demand response) and Scenario #6 (renewables) have higher NO_X emissions than those other cases. This is because in those scenarios, the capacity additions (specifically, demand response and wind) have lower energy output per unit of on-peak capacity added, so that other fossil fuel generating units on the system are operating more than in the other cases. Figure 10 shows the NO_X emissions by fuel category for Scenario #2 on the peak-load day of 35,000 MW under the common set of assumptions.

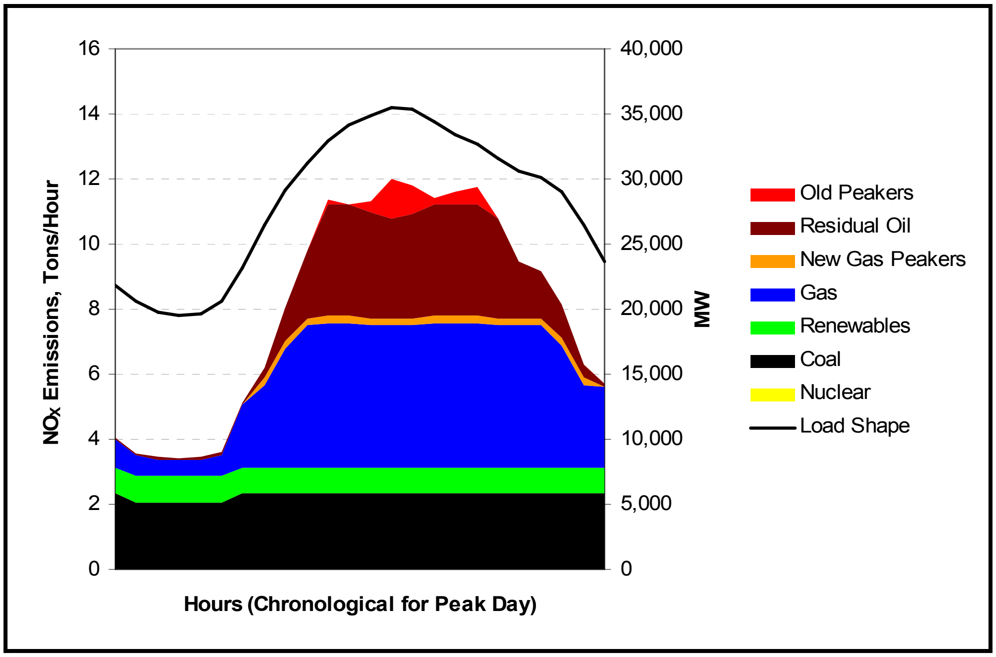

Figure 10: NO_X emissions by fuel category on the 35,000 MW peak-load day for Scenario #2 (energy efficiency and demand response) common-assumptions case, tons/hour.

5.3.1.3 Carbon Dioxide Emissions

The different scenarios produced varied patterns of CO_2 emissions, in large part depending on the degree and type of fossil-fired generation dispatched in the scenario and the portion of generation that comes from coal. Therefore, Scenario #4 (IGCC) has the highest CO_2 emissions (over 90 million tons annually). The other scenarios produce lower CO_2 emissions in the following order: Scenario #1 (queue), Scenario #5 (NGCC), Scenarios #2 and #6 (demand-side and renewables), and Scenario #7 (imports). Scenario #3 (nuclear) has the lowest CO_2 emissions, 53 million tons. The ranking relates directly to the relative amount of zero-emitting electric energy produced by the capacity added in each scenario. Figure 11 shows the total annual CO_2 emissions (million tons) for all the scenarios, grouped by sensitivity case.

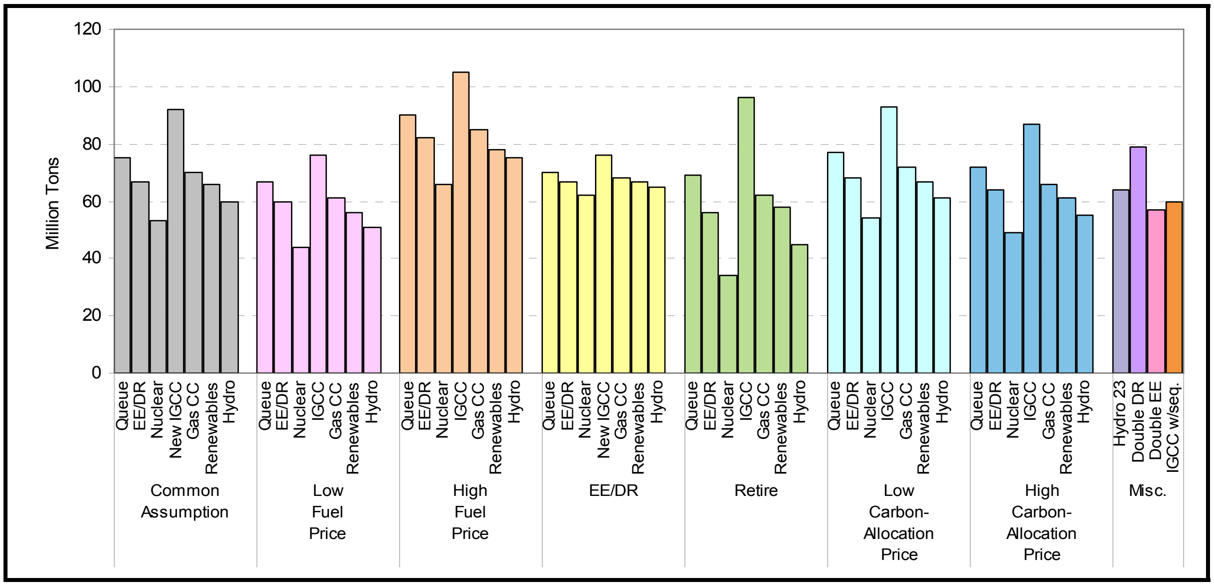

Figure 11: Total annual CO_2 emissions, grouped by sensitivity case.

Note: Table includes emissions for units that do not need to comply with RGGI requirements.

The high-fuel-price cases result in the highest CO_2 emissions. For Scenario #3 (nuclear), emissions increase from 53 to 66 million tons, and for Scenario #5 (IGCC), emissions increase from 92 to 105 million tons. The retirement sensitivity cases tend to lower CO_2 emissions relative to other cases, except for the IGCC case. The higher carbon-price sensitivity cases reduce CO_2 emissions somewhat relative to the common set of assumptions.

Table 8 shows the cases that would meet the RGGI allocation for New England on the basis of applying the total CO_2 emission adjustments (see Section 2.2.3), which reduced the emission results shown in Figure 11. The scenarios and cases exceeding the allocation indicate that New England power plants would need to buy additional allowances from RGGI sources outside New England, use greenhouse gas offsets allowed for compliance up to a maximum percentage depending on the CO_2 allowance price, or a combination of all measures.

Table 8
Scenarios and Cases That Appear to Be Lower than the RGGI 50.2-million-ton CO_2 Allowance Allocation to New England States

Scenario	Cases with Emissions Below New England's RGGI CO_2 Allocation (50.2 million tons)
1. Queue	None
2. EE/DR	None
3. Nuclear	All cases except the high fuel-price case and the case to replace 3,500 MW with EE and DR
4. IGCC	None
5. NGCC	None
6. Renewables	All except the high fuel-price case
7. Imports	Low fuel-price case; the case to retire 3,500 MW; and the case with the high CO_2-allowance price

5.3.1.4 Mercury Emissions

As expected, the results showed that mercury emissions are highest in coal-fired Scenario #4 (IGCC), producing as much as about 3,000 lb of mercury under the common set of assumptions, about 3,600 lb in the retirement scenarios, and about 1,500 lb in the low-gas-price scenario. Other scenarios produce far less mercury. Assuming controls that yield a 90% reduction would bring these amounts to within proposed mercury regulations.

5.3.2 Other Environmental Metrics

The percentage of output from renewable energy is 12.9% for Scenario #1 (the queue); 12.9% for Scenarios #2 (demand-side), #3 (nuclear), #4 (IGCC), and #5 (NGCC); 27.2% for Scenario #6 (renewables); and 26.4% for Scenario #7 (imports). These results indicate whether the scenarios will meet the RPS requirements, which may be 20 to 25% by the 2020 to 2025 period.[59]

The number of acres of land for siting new facilities (generating units and transmission) is shown in Table 9. The table does not indicate the extent of possible dual uses of land when siting transmission lines and wind generators. The land requirements do not reflect expansion of the regional natural gas infrastructure.

Table 9
High and Low Incremental Land Requirements in New England for the Scenarios (Acres)

Scenario	Generation	Transmission	Total
1. Queue	9,134 – 54,008	238 – 6,019	9,371 – 69,398
2. EE/DR	0	0	0
3. Nuclear	1,038 – 2,025	238 – 6,019	1,276 – 9,320
4. IGCC		238 – 6,019	631 – 9,350
5. NGCC	128 – 128	238 – 950	365 – 1,443
6. Renewables	127,449 – 232,727	2,257 – 13,781	129,706 – 246,507
7. Imports	0	11,880 – 29,462	11,880 – 29,462

The amount of cooling water for wet cooling at the large power plants are as follows:

- Queue scenario (#1)—12,100 gal/min
- Nuclear scenario (#3)—85,200 gal/min
- IGCC scenario (#4)—65,900 gal/min
- NGCC scenario (#5)—20,700 gal/min

[59] For example New Hampshire, the last state in New England to establish RPSs, has set the highest target among the six states: 25% by 2025. Also note tbat Connecticut classifies gas-fueled fuel cells and CHP as “renewable” sources of energy and includes them in its RPS percentages. More information on each state’s RPSs is available online at ___,

The scenarios not listed have no or less significant cooling requirements.

A savings is associated with energy efficiency and demand response compared with supply-side resources in that no additional transmission expansion would be required. Scenario #2 (demand-side) also reduces the amount of distribution system investment costs in the range of $100 million to $325 million.

5.4 Key Themes of the Results

Some of the key themes of the economic, reliability, and environmental results are as follows:

5.4.1 Themes of Economic Results

- ***The price for fossil fuels (natural gas and oil) is the most dominant factor affecting the costs and emissions for each of the scenarios.*** This can be seen in Figure 5 and Figure 11 for the LSE expense for wholesale electric energy and total CO_2 emissions, respectively. The absolute and relative levels of natural gas and oil prices tend to be the biggest factors affecting the amount of electricity produced by different technologies, total systemwide expenditures on energy production, and the total amount of emissions produced by power plants. For example, the sensitivity case for which natural gas price doubled also showed increases in wholesale energy costs to LSEs by approximately 50% across all scenarios. This same sensitivity case increased systemwide CO_2 emissions by more than 10 million tons for every scenario compared with the cases under the common set of assumptions. Fuel prices affect the energy mix, costs, and emission levels. This result is nothing "new" but a reality confirmed by the modeling of the various scenarios under different assumptions about fuel prices, carbon emission allowance prices, and other factors.

- ***The economic evaluation of expansion technologies must give full consideration to capital and operating costs as well as sources of revenues for the expansion technologies.*** For example, wind and nuclear resources tend to have high capital costs, causing them to be relatively expensive to build. These technologies show a modest-to-significant gap between the net revenues these technologies receive in the New England wholesale electric energy markets and their annual revenue requirements. Therefore, to induce investment in these technologies and have them enter the market, some other means would need to be used to fill this revenue gap, such as through payments from the Forward Capacity Market, the provision of ancillary services, tax credits, the sale of emission allowances, Renewable Energy Certificates, the effects of any new regulatory requirement, and other sources.

- ***Alternatively, energy efficiency and demand response show sufficient revenues from the electric energy and capacity markets to economically justify investment.*** Additional natural-gas-fired generators are also economic capacity additions. Other technology types (e.g., wind, nuclear) heavily depend on non-energy-market revenues to be economically viable. The results for Scenario #7 (imports) also show net energy market revenues and assumed capacity revenues that exceeded the annual revenue requirements for building transmission within New England. However, added costs for building transmission in neighboring systems could substantially change the economic evaluation of the import scenario. Actual decisions would need to consider these and other factors that would affect any negotiations for purchased power.

- ***Adding resources with large amounts of electric energy production, low operating, costs, and low emissions will reduce production costs, energy prices, and emissions.*** Compared with Scenario #1 (the queue), expansion technologies in all the other scenarios that provide substantial electric energy to the system have lower average marginal clearing prices, lower average overall energy-related costs, and lower emissions (see Table 7). For example, wind, imports from neighboring systems, nuclear, and energy efficiency, all of which provide energy—or energy savings—at low to no fuel cost result in the lowest systemwide electric energy prices, emissions, and use of fossil fuels.
    - Electric energy clearing prices in all cases except Scenario #2 (demand-side) are lower than the queue case.
    - The scenario analysis simulation results do not reflect dynamic changes, such as lower gas prices that could materialize in a scenario that reduces the demands for natural gas, such as the energy-efficiency cases.
    - The new gas-fired resources on the margin are more efficient than in the past and are thus likely to reduce marginal clearing prices compared with existing marginal gas-fired resources that have set average clearing prices in the past.
    - Scenarios, such as Scenario #1 (the queue), which largely depend on peaking and fast-start resources, are likely to lead to higher average marginal energy costs.

- ***Natural gas will remain the marginal fuel.*** In all cases under the common assumptions, natural-gas-fired power plants remain on the margin approximately 90% of the time. Even after adding 5,400 MW of a new technology type (combined with the 2,600 MW of new capacity in the queue), natural-gas-fired plants typically are the power plants last dispatched to meet demand in most hours of the day. This holds across virtually all assumed cases. Therefore, average clearing prices in New England's wholesale electricity markets tend to be more dependent on natural gas fuel costs than the different expansion technologies used the scenario analysis cases (see Figure 4).

5.4.2 Themes of Reliability Results

- ***The system capacity mix would not alter a high dependency on natural-gas-fired capacity under any scenario.*** Adding large amounts of different types incremental capacity (i.e., the 5,400 MW of each technology added to the same 2,600 MW of the mix of resources currently in the ISO's Generator Interconnection Queue) does not radically change the overall mix of gas-fired capacity in New England. This is largely because each of the cases assumed that the 5,400 MW of one technology type was added to a base of approximately 31,000 MW existing in 2007 plus 2,600 MW of resources reflecting a mix of fuels in the Generator Interconnection Queue. Of the total 39,000 MW of resources, a minimum of 13,900 MW uses natural gas as a fuel. Therefore, even adding a deliberately large quantity of a single technology or fuel type does not eliminate the already strong dependency on natural-gas-fired units in the region.

- ***The greatest changes in the capacity mix tend to occur in the sensitivity cases that assumed that the oldest 3,500 MW of generating capacity in the region would retire and be replaced with that scenario's core technology.*** For Scenario #5 (NGCC), natural-gas-fired unit capacity comprises 50% of the total systemwide capacity of almost 39,000 MW. This grows to 58% of the overall capacity in the retirement sensitivity case. By comparison, in the other scenarios, natural gas capacity comprises approximately 35% of the total systemwide capacity, even in the retirement sensitivity case.

- ***Adding thousands of megawatts of demand-response capacity, as assumed in this Scenario Analysis could lead to trade offs.*** Adding some demand-response resources where additional electric-energy-producing resources (or energy-efficiency savings) are not particularly needed (i.e., where few electric energy, economic, or environmental benefits will result) can be advantageous. Demand response can also capture benefits not fully analyzed in this analysis, such as providing operating reserves, reducing price spikes and congestion, reducing emissions produced by existing fossil-fired peaking generators, and others. But adding "too much" peaking capacity at the exclusion of resources with more baseload characteristics may lead to unexpected consequences of higher wholesale electric energy prices and greater emissions.

5.4.3 Themes of Environmental Results

- ***With the exception of the Scenario #4 (IGCC), the retirement case results show lower emissions***. Compared with the results for each scenario using the common set of assumptions, the results for the sensitivity analyses that involve the retirement of the oldest generating capacity in the region result in fewer emissions of nitrogen oxides, sulfur dioxide, and carbon dioxide and lower production costs and oil consumption. These results tend to occur across all scenarios that apply the retirement assumption, but it also means that more capacity must be added (and paid for) to make up for the retired units.

- ***Relatively high reliance on fossil-fuel-based peaking resources, even in combination with some form of emission-free demand response, can result in an overall increase in air emissions.*** The scenarios and sensitivity analyses that include a significant increase in demand response to shave demand during hours of peak energy use also produce relatively high levels of air emissions (NO_X, SO_2, and CO_2,), oil use, and production costs. This is because, in these cases, other power plants—typically some combination of plants that run on fossil fuels—operated in more hours than in other scenarios. In Scenario #2 (2,700 MW of demand response and 2,700 of energy efficiency) and in the sensitivity analyses involving even greater additions of demand response), the reduced capacity needs provided by demand response offered little relative savings in electric energy production. This effect can be seen most dramatically in the cases where demand response replaces energy efficiency, which show higher emissions, production costs, and fossil fuel use than in cases where energy efficiency provides the same capacity but considerably more electric energy (see Figure 10).

- ***Because CO_2 emissions vary across the scenarios, regional compliance with RGGI will also vary.*** Scenario Analysis modeling did not constrain output or CO_2 emissions at the region's power plants. Under almost all scenarios, CO_2 emissions of all resources exceed the 50.2-million-ton CO_2 allowance assumed to be allocated to New England states for the study year. Even subtracting emissions associated with the plants not covered under the RGGI program, the emissions from New England's power sector exceed 50 million tons in most scenarios.[60] For example, four core scenarios show total systemwide CO_2 emissions of over 50.2 million tons for RGGI resources across all sensitivity cases. However, Scenarios # 3 and #6 (nuclear and renewables) meet the 50.2-million-ton CO_2 allowance except for the sensitivity case when natural gas prices are high. These results suggest that RGGI compliance would be facilitated by adding significant energy efficiency or substantial amounts of energy with low or zero CO_2 emissions or by having affected power generators buy additional CO_2 allowances from sources outside the region.

[60] Only fossil-fueled power plants over 25 MW in size are covered by RGGI requirements, so the Scenario Analysis results need to be adjusted to account for CO_2 emissions from plants less than 25 MW. Additionally, biomass plants are considered to be carbon neutral under RGGI. Therefore, 5 million tons was subtracted for these non-RGGI units in all the scenarios except Scenario #6 (renewables), In this scenario, an additional 12 million tons was subtracted to account for 675 MW of biomass units and 675 MW each of fuel cells and CHP units that are under 25 MW.

Section 6
Summary and Conclusions

The Scenario Analysis initiative has been designed to provide the region with information about the implications of various choices for meeting consumers' future needs for reliable, low-cost, efficient, and environmentally sound supplies of electricity. In sponsoring the Scenario Analysis exercise, the ISO has taken no position about which is the "right" or "wrong" path. Nor has the ISO asked stakeholders to reach a consensus about what path the region *should* take or which technology path or set of outcomes are preferable. The ISO did not even ask stakeholders to accept any of the seven scenarios as a realistic portrayal of what *will* occur in the future. The understanding was to use a common set of assumptions about key elements of the future state (e.g., fuel prices, a level of demand that might need to be planned for, the characteristics of electricity technologies), observe how the results might change under different technology paths, and allow the resulting information to be available to public and private decision-makers as they wrestle with these issues going forward.

The exercise was carried out, therefore, to shed light on possible outcomes of taking one particular technology path or another. Examining the detailed results of the scenarios analysis will help reveal the implications of what different investment options mean for the region and the resultant impacts on the cost to produce electricity, electricity prices, electric power supply reliability, fuel diversity, environmental impacts, and other metrics of interest.

These "what if" analyses have inherent constraints on the type of information they are able to provide to the end user. Quantitative models and other tools are limited in their ability to depict how a system would actually perform if the assumed conditions occurred in the future, to predict how the electric power system interacts with other elements of the economy, and so forth. These are complex systems, and no model can simulate their performance with complete accuracy. In light of the technical limitations of tools of prediction (as well as time and other resource constraints), steps were taken in this Scenario Analysis initiative to simplify key elements of the system to generate results that are informative rather than predictive of how future electric technology choices will play out in the region's electric energy system. The results should be viewed as providing directionally appropriate information, while not necessarily providing detailed and "accurate" information.

The results can be helpful in providing insights for others in conducting more detailed studies and for more in-depth policy analysis and discussion. The ISO encourages interested parties to compare the results of the outcome metrics for the different scenarios and reach their own conclusions about the various technology paths. These results are intended to inform future discussions about different public policies that may be necessary to pursue if one particular technology path or paths holds particular interest or value for the region.

6.1 General Themes

In general, the results show that lower electric energy prices and reduced air emissions are possible by adding resources that provide relatively high amounts of electric energy, have low or no fuel costs, and emit few pollutants. The results also show that New England will continue to depend highly on natural gas for power production. On the basis of the assumptions used in this analysis, regional energy prices and subsequent air emissions will be driven by the price of natural gas. CO_2 emissions vary considerably across the scenarios, with implications for the ease with which the region satisfies its requirements under RGGI.

6.2 Use of the Data

The Scenario Analysis has produced volumes of detailed information about the impacts of the potential technology paths for the region's future electric power system. This report has provided the tip of "information iceberg" that is available about the scenarios, their economic, environmental, and reliability impacts and how those impacts change under different sets of assumptions. The complete results are available to the public on the ISO's Web site. Potential users may access the data to gain a more complete view of the estimated impacts of the seven core scenarios and the many sensitivity analyses performed on them.

Given that these depictions of the future state of New England's regionwide bulk electric power system are based on many assumptions, data inputs, and modeling approaches, users should remember to take those underlying technical issues into account as they review and consider the results of these analyses. For example, the core scenarios set out scenarios that incorporate relatively homogeneous technology paths, adding 5,400 MW from a single type of technology. In the real world, more diverse mixes of technologies may (or may not) be added in the future. That said, the use of these deliberately exaggerated technology scenarios helps to sharpen the differences in results among the cases analyzed and may help inform stakeholders' understanding of the trade-offs (among economic, reliability, and environmental outcomes) from one technology path to another.

Among other things, the results of the analyses in general indicate the relative importance of absolute and relative prices for fossil fuels in the future in shaping the character of impacts from electric sector production and use. History has provided many powerful examples of the difficulty and perils of planning to achieve certain outcomes based on particular assumptions about future fossil fuel prices; being wrong in fuel-price forecasts is commonplace. Thus, looking at technology path options with an understanding that fossil fuel prices may well be higher or lower than expected may lead to considerations of technology options that perform well no matter which direction fuel-price paths may take. At the very least, this understanding suggests that a certain amount of caution may be appropriate in making plans based too strongly on any particular forecast of prices.

Readers wanting to use the results to carry out further analyses will be able to do so using the information provided on the ISO's Web site. To assist stakeholders in analyzing the data, the ISO is also posting a spreadsheet tool that can be used to "mine" the information, make other investigations, and even explore the impacts of making different assumptions. The spreadsheet will enable users to incorporate, for example, different cost assumptions with regard to the capital costs of particular technologies, the length and number of transmission lines required for a particular scenario, and modification to other types of costs. The spreadsheet on the Web site is accompanied by instructions to assist users in understanding the capabilities of the tool and the assumptions that users will be able to change.[61]

[61] The user will be able to make changes to adjust "post-processing" assumptions about capital costs of the generating resource or demand-side measures, the transmission costs and requirements, distribution system costs and requirements, and such other things as the costs of carbon sequestration and [xxx]. The user, however, will not be able to rerun the production simulation model with different assumptions.

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