Electricity Costs White Paper

ISO New England Inc.
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Executive Summary

Wholesale electricity prices in New England are directly linked to the costs of the fuels used by generating units to produce electricity. Since many of the region's power plants are fueled by natural gas and these plants often set the wholesale electricity price, the increase in electricity prices in fall 2005 was a reflection of the increase in the price of natural gas during that period. Similarly, in late fall/winter 2005/2006, wholesale electricity prices decreased with the decrease in natural gas prices. In turn, some New England utility companies have begun to reduce retail electricity rates.

Wholesale electricity prices are also linked to the amount of electricity consumers use at peak times, primarily during the summer. Power consumption on the hottest summer days has been growing at about 2% each year, which is higher than the growth in average consumption. This consumption trend drives the requirement to build additional resources (e.g. peaking units), increasing the capacity costs of the region. It also is creating an underutilized power system where resources are built to satisfy demand for only a few days of the year.

This paper discusses the results of an ISO New England (ISO) analysis that evaluated the drivers of electricity costs in terms of their fixed and variable components, with projections through 2015. To indicate electricity-price trends, the analysis projected total electricity costs for the region in 2010 and 2015, based on the region taking no actions to change its mix of capacity resources or decrease demand (i.e., a "business-as-usual" scenario). These costs were compared to the 2006 expected costs for electricity.

The analysis also used actual electricity usage and bidding data for 2005 to estimate the potential impact that various options to control electricity costs, such as policy actions that alter the "business-as-usual" scenario, can have on the electricity market. These options broadly include building low-cost baseload generation (e.g., renewables, clean coal, and perhaps nuclear power) and reducing peak usage. Giving customers the opportunity to respond to real-time prices can potentially reduce peak loads, such as through traditional price-based demand-response programs, energy-efficiency measures, and conservation efforts. Reducing demand in response to high prices during peak periods could also reduce the need to add electricity infrastructure.

Highlights of the Analysis

The major findings of the analysis are as follows:

- Fuel costs, primarily natural gas, are a principal determinant of electricity costs.
- The addition of low-cost baseload power plants and price-responsive demand are effective ways to control costs.
- Adding 1,000 megawatts (MW) of supply produced by low-cost plants will save New England consumers $600 million a year.
- Reducing usage by 5% during on-peak hours will lower consumer cost by $580 million a year. On-peak price signals that reveal wholesale prices and more aggressive on-peak energy-efficiency programs can bring about these reductions.
- A 500 MW increase in traditional demand-response program participation will cut costs by $32 million a year.

- Assuming continued high fuel prices, taking no action (a business-as-usual scenario) will result in electricity costs rising with increases in demand and fuel prices. A 5% increase in power usage will increase costs by $700 million.

Figure 1 shows the estimated cost impacts associated with adding new low-cost plants, increasing a combination of price-responsive demand and more aggressive on-peak energy-efficiency measures, and increasing demand response compared with the costs of a business-as-usual scenario. These estimates are a combination of electricity and capacity costs. They do not include the costs to implement each measure, and no ranking of responses is implied. That is, while the cost savings of 500 MW of traditional demand response appears small, it may be that demand response is more easily implemented and less expensive to achieve than building a new baseload generator. These estimates intended to be representative of the effects of such actions and investments. Changes in actual consumer costs could vary widely.

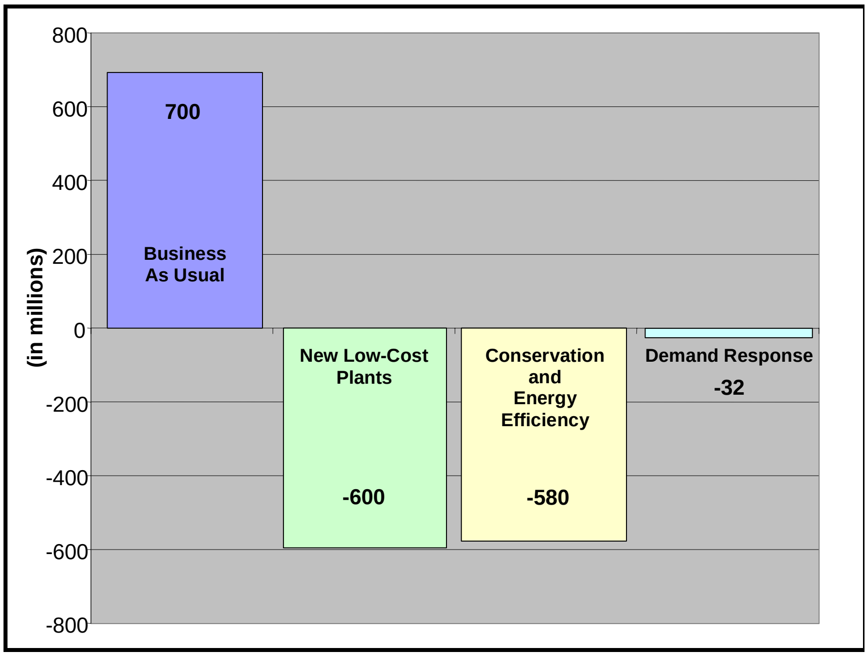

Figure 1 Impacts of various “solutions” for controlling electricity costs.

Components of Electricity Rates

The ISO estimated the following about the components of electricity rates:

- Power costs, which reflect the cost of producing electricity and vary with the global fuel markets, will make up approximately half of the average consumer’s electricity bill in 2006. Of this, fuel and capacity costs will account for roughly 95% of the total.
- Transmission and distribution costs, which will make up the remaining 50% of the bill, are regulated and reflect the cost to build, maintain, and operate the regional transmission system and local transmission (distribution) networks.

- Over the next 10 years, power costs should be expected to track natural gas prices and capacity cost trends, unless targeted action is taken to control these costs. Capacity costs are expected to increase by 75%, as the region implements a new capacity market to ensure supply keeps up with growing demand. Transmission costs, while a small component of total costs, will rise by 77%, as the region builds and pays for new lines. Distribution costs are expected to remain fairly stable as they generally have in recent years.

Action Plan for Managing Electricity Costs in New England

Actions that can reduce electricity costs in New England include the following:

- Improvements in energy efficiency—stimulated by some form of dynamic pricing that indicates to consumers when prices are highest and creates an incentive to reduce electricity use at peak times—to lessen the need to add new plants
- The development of power plants using low-cost fuels, such as wind, nuclear, and clean coal, which can lower power costs by displacing the operation of higher-cost power plants
- The facilitation of these responses by state officials, who can increase the control of electricity prices in the region through the following measures:
    - Adopting retail-rate policies that reveal real-time electricity prices to businesses and residential consumers and provide incentives for managing the use of electricity during these high-price peak-use periods
    - Enabling the siting of new supply resources that use wind, clean coal, nuclear, and other alternative energy sources
    - Implementing additional programs to promote greater energy efficiency and use of customer-operated resources, such as load management and distributed generation to reduce on-peak load

Electricity Cost Drivers

End-user electricity costs are based on three components of electricity production and delivery—power generation, transmission, and distribution. Each component is part of both the regulated and competitive environments. However, the mechanisms for ensuring the efficient production and delivery of electricity and for investing in these components differ between the two environments. In a regulated environment, state and federal regulatory bodies manage costs. In a competitive environment, market mechanisms drive some costs and investment decisions (power generation, capacity, ancillary services), while other costs (transmission and distribution) continue to be governed by regulatory review.

Figure 2 shows the approximate expected average 2006 costs of the three main electricity cost components in New England. Transmission costs are small relative to the total costs, with electricity and distribution costs at similar levels. Each cost category can be further segregated into variable and fixed costs. Variable costs are generally associated with power production, with fuel costs the dominant component. Fixed costs include the capital costs for required infrastructure (transmission and distribution systems, power plants) and the personnel and organizational costs for maintaining and operating the power system, which do not vary significantly with demand.

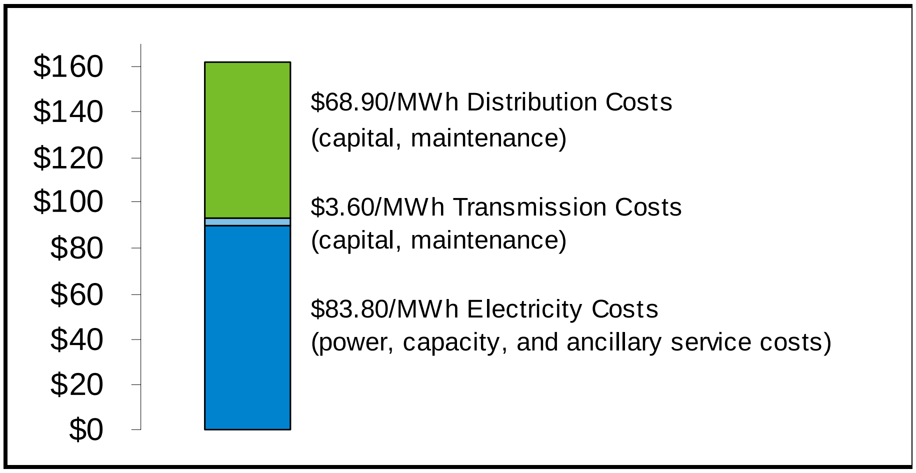

Figure 2 Components of the average forecast New England retail consumer cost of $156/megawatt-hour (MWh) in 2006.

Note: The electricity cost of $83.80/MWh assumes that the average locational marginal price (LMP) in New England for 2006 will be $74, calculated by adjusting the 2005 average LMP for changing natural gas costs. Gas costs are based on U.S. Department of Energy, Energy Information Administration (EIA) forecasts. Capacity costs are assumed to be approximately $3/kW-Month, the expected value at the end of 2006. These costs are estimates of average New England costs and represent actual costs; they may not match those of any particular consumer.

Wholesale electricity costs can be separated into fuel costs, variable operation and maintenance (VOM) costs, capacity costs, and ancillary service costs. Figure 3 shows a sample breakdown of these costs. Fuel costs are the majority of wholesale electricity costs. The figure assumes that a moderately efficient combined-cycle gas-fired power plant is the marginal unit, that natural gas costs are $7.50/million British Thermal Units (MMBtu), and that the capacity market pays $3/kilowatt (kW)-Month. In the example, the major components of wholesale electricity market costs are capacity and fuel costs, comprising approximately 95% of total costs.

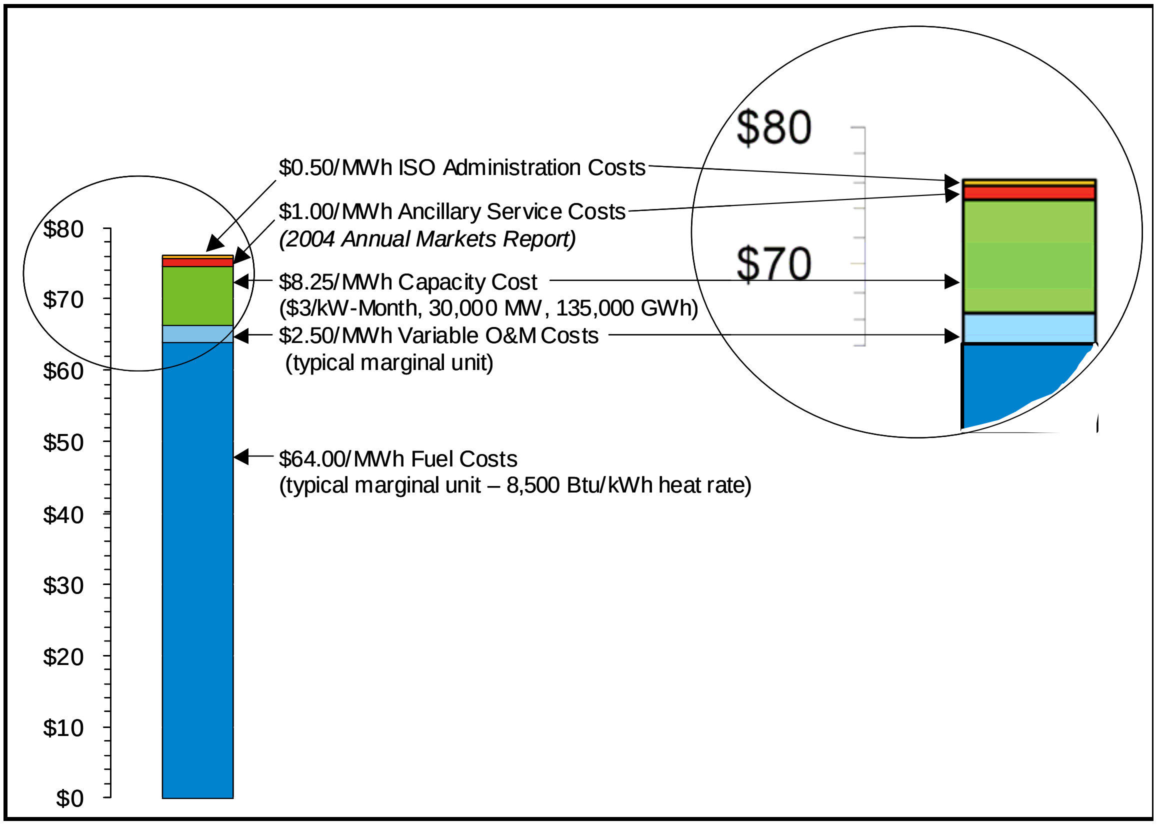

Figure 3 Components of the wholesale electricity cost for a typical hour with a gas unit on the margin, Total $76.25/MWh (2005).

Note: The typical hourly cost shown in Figure 3 differs from the average price shown in Figure 2 to allow the cost components to be more clearly disaggregated. The typical hourly cost is not a price projection, but a snapshot of the different components that make up electricity costs.

Figure 4 shows a projection of the typical wholesale electricity costs shown in Figure 3. Figure 4 uses EIA forecast data for natural gas prices to calculate projected fuel-operating costs. The EIA forecast is that the average natural gas price in 2006 will be $7.24/MMBtu, with a steady decline to a low of $5.08/MMBtu in 2015. These numbers are in real dollars and are adjusted slightly to reflect higher costs when delivered to New England. The projected fuel costs are used to calculate projected wholesale electricity costs over the next 10 years. The projected market capacity costs are based on transition payments prior to the implementation of the Forward Capacity Market. After 2009, the costs are based on an expected Forward Capacity Auction (FCA) clearing price of $7.50/kW-Month. After deducting assumed peak-energy rents of $2.50/kW-Month, the net capacity cost is $5.00/kW-Month. Market capacity costs also increase after 2010 due to the decreased use of capacity or declining load factors (i.e., when capacity requirements increase at a faster rate than the overall growth in electricity consumption). Other costs, which include unit VOM costs, ISO administrative costs, and ancillary service costs, are held constant over the period.

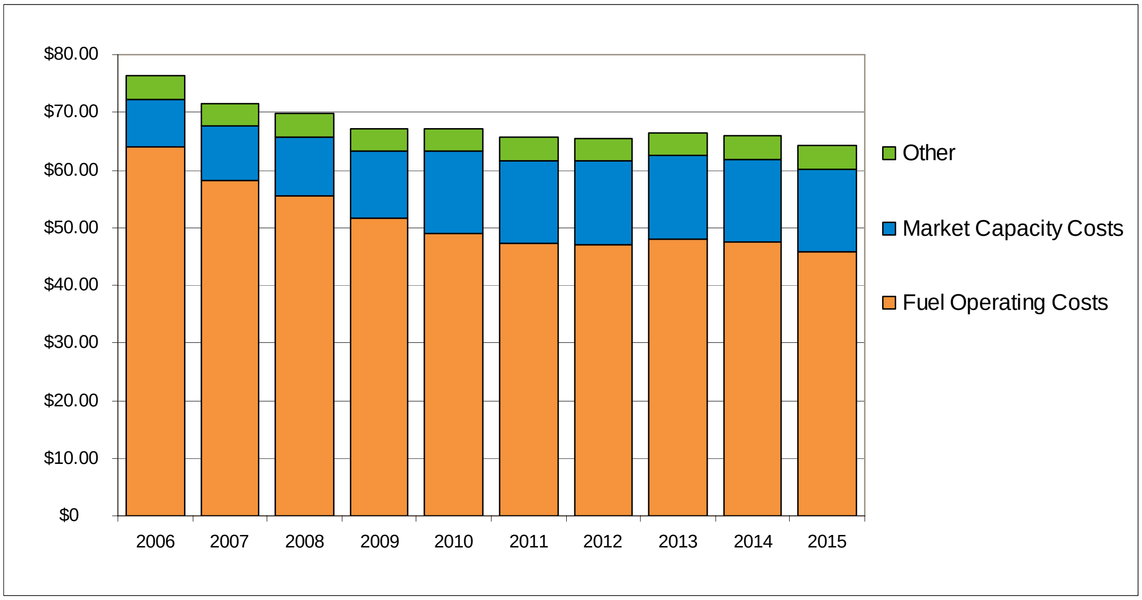

Figure 4 Projected New England wholesale electricity costs for a typical hour ($/MWh in 2005 $).

Transmission system costs are a combination of the cost to build the transmission system, amortized over the expected useful life of each component, and the costs of operating and maintaining the system. Figure 5 shows projected New England transmission costs by year per megawatt-hour of New England electricity demand. These calculations assume that projected transmission upgrades are completed, that their costs are recovered from consumers, and that total electricity demand increases as forecast in the ISO's *2005 Regional System Plan* (RSP05).[1] Total costs are broken down into carrying charges, depreciation of assets, property taxes, and other operations and maintenance expenses. Transmission costs increase as costs for new transmission projects are moved into rate base and are recovered from consumers. Figure 5 assumes that major planned transmission projects are completed on schedule.[2] It does not include costs for the Southern New England Transmission Reinforcement (SNETR) Project.[3]

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1 ISO New England *2005 Regional System Plan*, October 20, 2005. See http://www.iso-ne.com/trans/rsp/index.html.

2 These projects include the Southwest Connecticut Reliability Project Phase I and Phase II; the NSTAR 345 kV Reliability Project upgrades in the Boston area, the Northwest Vermont Reliability Project, and the Northeast Reliability Interconnect (NRI) Project (i.e., the Maine upgrades).

3 The SNETR project is comprehensively addressing a number of significant long-term reliability issues affecting western Massachusetts in the Greater Springfield area, Rhode Island, and Greater Connecticut.

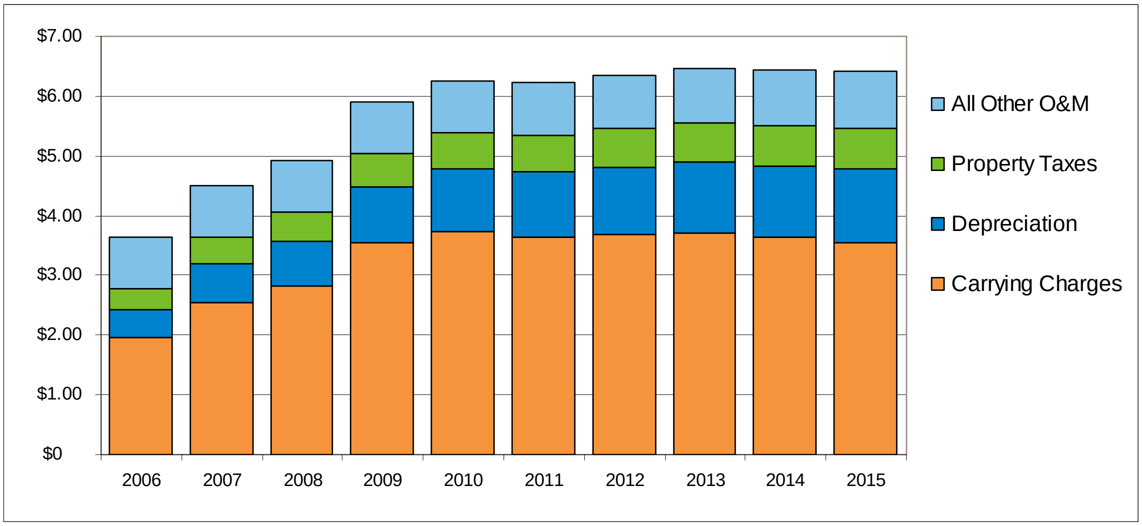

Figure 5 Projected New England transmission costs ($/MWh in 2005 $).

Distribution system costs are a combination of the cost to build the distribution system, amortized over the expected useful life of each component, and the costs of operating and maintaining the distribution system. Figure 6 shows these projected costs. These costs are not broken out the same way as transmission costs because detailed cost data are not readily available. Relative to electricity and transmission costs, these costs are expected to be stable.

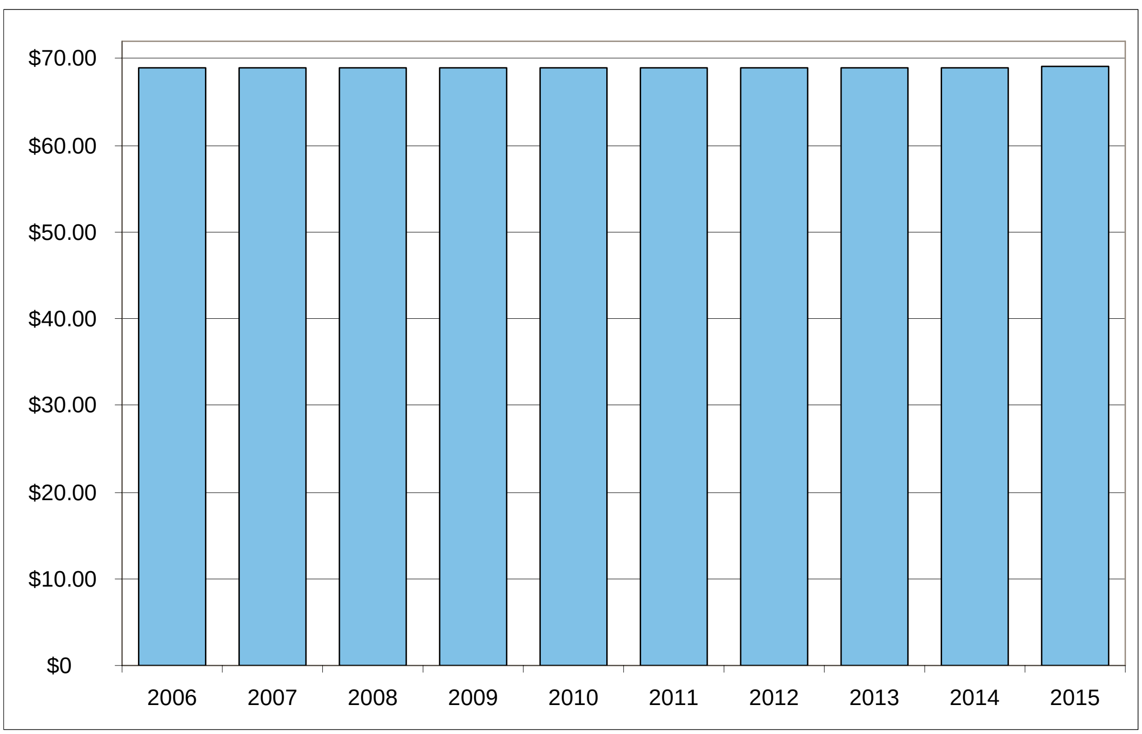

Figure 6 Projected New England distribution costs ($/MWh in 2005 $).

Electricity costs are comprised largely of fuel and capacity costs, with natural gas costs expected to decrease and capacity costs expected to increase in the future. Transmission costs, while a small component of total costs, are expected to nearly double over the next 10 years. Distribution costs, while large, are very stable relative to electricity and transmission costs. These costs are largely under the jurisdiction of state regulators.

Future Costs of Taking No Action

Accurate electricity price forecasts are difficult if not impossible to develop due to their strong dependence on fuel prices. To provide some indication of the drivers and trends in electricity prices, this analysis projected the all-in costs of electricity in 2010 and 2015, compared with the expected costs in 2006 shown in Figure 2. These projections are labeled “Business as Usual” and combine the separate electricity, transmission, and distribution projections presented above. Three business-as-usual projections (scenarios) are provided: the first based on EIA forecast natural gas prices, which decline over the next 10 years; the second assuming flat natural gas prices; and the third assuming that natural gas prices increase by 5% per year between 2006 and 2015.

These costs were computed assuming that peak loads grow as projected in RSP05, that the large transmission projects discussed in RSP05 are built, and that natural gas continues to be the incremental source of most new generation in New England. Prices are in constant 2005 dollars. Natural gas price forecasts in the first scenario, shown in Table 1, are from the EIA.

Table 1
Business-as-Usual Electricity Prices: EIA Gas Prices ($/MWh)

	2006	2010	2015
Wholesale electricity[a]	$75.50	$62.00	$59.10
Capacity[b]	$8.30	$14.30	$14.50
Transmission	$3.60	$6.30	$6.40
Distribution	$68.90	$69.00	$69.00
Total	**$156.30**	**$151.60**	**$149.00**

[a]Calculated by adjusting 2005 prices for projected gas prices and adding ancillary service costs ($1/MWh) and ISO costs ($0.50/MWh)
[b]The capacity costs for 2006 are assumed to be $3/kW-Month. The capacity costs for 2010 and 2015 are expected to be the estimated cost of new entry ($7.50/kW-Month) minus assumed peak-energy rents of $2.50/kW-Month, for a net cost of $5/kW-Month. These costs are only expected to be in the range of possible costs, not to forecast actual prices. Annual energy consumption data are from RSP05 forecasts.

The projected costs shown in Table 1 are driven primarily by increased capacity costs, falling natural gas prices, and additional transmission investment. The capacity costs are driven by peak loads that are increasing faster than average electricity consumption and a redesigned capacity market expected to spur new investment.

Table 2 uses the same assumptions as Table 1, but holds natural gas prices constant at expected 2006 levels. This results in higher all-in prices than shown in Table 1.

Table 2
Business-as-Usual Electricity Prices: Flat Natural Gas Prices ($/MWh)

	2006	2010	2015
Wholesale electricity	$75.50	$75.50	$75.50
Capacity	$8.30	$14.30	$14.50
Transmission	$3.60	$6.30	$6.40
Distribution	$68.90	$69.00	$69.00
Total	**$156.30**	**$165.10**	**$165.40**

Table 3 assumes that natural gas prices increase at 5% per year in real dollars. This results in the highest prices of the three scenarios.

Table 3
Business-as-Usual Electricity Prices: Natural Gas Prices Increasing 5% per Year ($/MWh)

	2006	2010	2015
Wholesale electricity	$75.50	$87.00	$105.00
Capacity	$8.30	$14.30	$14.50
Transmission	$3.60	$6.30	$6.40
Distribution	$68.90	$69.00	$69.00
Total	**$156.30**	**$176.60**	**$194.90**

Wholesale electricity prices vary by 78% between the projections using EIA natural gas price forecasts and those assuming that natural gas prices increase by 5% per year. Total consumer costs per megawatt-hour vary by 31%.

Responses to Cost Projections

The projected costs under the business-as-usual scenarios and the risk associated with volatile natural gas prices may be reduced in a number of ways. These fall into two broad categories. One category is to build low-cost generation, and the other is to reduce peak loads to avoid incremental infrastructure investment. Electricity costs would be reduced by displacing high-cost resources with low-cost resources, by reducing the need to build and pay for additional infrastructure, or a combination of both.

Current market signals appear to provide a strong incentive for building low-cost generation using available technology. While natural gas once looked like a low-cost alternative with which to displace existing oil resources, currently, renewables, coal, and possibly even nuclear power look cost-effective. While the increased incentive to build is clear, less recognized is the impact that adding baseload resources could have on market prices. Because the lowest-priced resources are selected first for commitment and dispatch, adding an inexpensive resource necessarily displaces the otherwise marginal units, lowering prices throughout the region. This effect can be significant.

Reducing peak loads reduces the need to add generation and transmission infrastructure, which lowers costs. Current load profiles require substantial investments for serving load during only a handful of hours each year. Reducing demand in that handful of hours can have a disproportionate impact on infrastructure needs. Giving customers the opportunity to respond to accurate wholesale price signals can provide market incentives for them to reduce demand during these times, such as through energy efficiency, load management, distributed generation, and real-time demand-response.[4] State-sponsored programs that assist consumers in better utilizing resources on the customer side of the meter would enable such consumers to respond to price signals and lower their electricity bills.

This analysis estimated the electricity market impact of each of these actions, using market loads and offer data for 2005. For each hour of the year, a modeled market price was calculated by stacking the supply offers in order and identifying where supply and demand intersect. This intersection point determined the hourly price. Separate model runs were then executed, with a single change to the input data corresponding to a change in either resources or demand. For example, a baseload resource was added to the supply curve each hour, or a certain amount of energy efficiency was assumed. The prices from these runs were compared with the baseline-calculated prices to estimate the market effect of the various modeled actions, conditional on 2005 fuel prices, actual 2005 resources and availability, and 2005 hourly loads.

Capacity-market impacts were calculated from the total capacity cost for New England, assuming that the Forward Capacity Market is in place. The net cost of capacity was assumed to be $5/kW-Month ($7.50/kW-Month in the FCA net of peak-energy rents, as assumed earlier). Capacity requirements in the business-as-usual case were estimated to grow linearly with peak-load growth. Reductions in peak-load growth through demand response, energy efficiency, and other measures reduced costs by $5/kW-Month because of reduced capacity needs.

Thus, the scenarios used 2005 power market data and results as indicators for future years. It was assumed that, in the future, the capacity market will clear at the cost of new entry. Because the future capacity market is still under development, using 2005 capacity-market results is not appropriate.

The following scenarios were modeled:

1) Addition of a 1,000 MW price-taking baseload resource
2) Addition of a 1,000 MW clean-coal generator, assuming that only clean coal can be permitted and sited
3) Assumption of 5% load growth without generation addition
4) Assumption of 5% reduced on-peak consumption
5) Addition of 500 MW of load response

Table 4 provides model estimates of the change in the wholesale electricity price, the change in electricity production costs, and the change in capacity costs under each scenario. The table shows these changes as follows:

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[4] A more sophisticated analysis of the potential benefits of revealing real-time prices to consumers is available in, "Simulating the Benefits of Improved Linkages between Wholesale and Retail Electricity Markets," by Peter Cappers, Bernie Neenan, and Henry Yoshimura. Presented at the Rutgers Advanced Workshop in Regulation and Competition, May 18-19, 2006.

- The changes in the wholesale electricity price are shown as percentages and as changes in total consumer electricity costs.
- The changes in production costs are shown as percentages and changes in total electricity production costs.
- The capacity cost changes are shown as percentages and changes in total capacity payments to capacity resources.

These estimates are intended to be representative of the effects of such actions and investments. Changes in actual consumer costs could vary widely from these estimates. For example, 2005, the base year in the modeling analysis, experienced relatively few high-priced hours. An increased number of high-priced hours in future years would increase the calculated savings from load-response programs.

The modeling results suggest that substantial reductions in consumer and production costs can be achieved through market investment in low-cost baseload resources and reductions in consumer demand. Reduced consumer costs can occur both because of decreased electricity prices and because of decreased capacity requirements. It is assumed that market signals are sufficiently strong for investment in low-cost baseload resources such that investments would be made without any additional market incentives or costs. Thus, capacity costs are unchanged as new baseload resources displace existing, higher-cost resources.

Table 4
Summary of Scenario Results (2005 $)

	% Change in Wholesale Electricity Price	Change in Total Consumer Costs[a]	% Change in Production Costs	Change in Total Production Costs	% Change in Total Capacity Costs	Change in Total Capacity Costs[b]
1) Add baseload	-5.70%	-$600 million	-19%	-$470 million	-	-
2) Add coal	-5.60%	-$590 million	-11%	-$300 million	-	-
3) 5% growth	5.80%	$600 million	16%	$420 million	5.00%	$90 million
4) 5% reduction	-4.70%	-$490 million	-14%	-$360 million	-5.00%	-$90 million
5) Load response	-0.02%	-$2 million	-0.01%	-$0.5 million	-1.70%	-$30 million

[a] Assumed total wholesale electricity consumer costs in 2005 of approximately $10.4 billion.

[b] Installed Capacity Requirement of 30,000 MW in 2005, at $5/kW-Month net capacity cost, results in a base capacity cost of $1.8 billion/year.

Conclusions

Based on the results of this analysis, the ISO concludes that without action, capacity and infrastructure costs will continue to rise. Fuel prices, primarily for natural gas, will continue to strongly influence total electricity costs. Adding new low-cost resources could have a large price effect; though not discussed in this paper, difficulties in siting these resources are an impediment to this market response. Energy efficiency, which is a likely response by retail customers to prices that reflect the true cost of wholesale power, can produce large savings in both energy and capacity costs.