ANALYSIS GROUP
ECONOMIC, FINANCIAL and STRATEGY CONSULTANTS

New England Energy Infrastructure –
Adequacy Assessment and Policy Review

Prepared For:
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HIGHLIGHTS

Energy is, once again, front page news. High energy prices, lost oil and gas production equipment in the Gulf, looming winter heating bills, refinery constraints. The energy infrastructure we all rely on suddenly seems inadequate and too vulnerable to meet our desire for reliable energy at reasonable prices. This report focuses on the adequacy of energy infrastructure in New England, and the steps we must take as a region to meet energy reliability, price and public policy goals. The highlights of this report are:

- **Energy infrastructure is vital to our region's economy.** Like most modern economies, New England takes for granted that its energy infrastructure will provide the power and other fuels needed by households, local business, and industries. The region is at a point, however, where we can no longer take the issue for granted.

- **The region needs new energy investment.** New energy infrastructure is needed to keep up with growth in demand, and to help the region better weather the recent and likely future turbulence in energy markets. To complicate matters, much of the region's electric and gas infrastructure is aging, and may need to be replaced or undergo improvements to remain in operation. We are at a critical point today if we are to avoid resource adequacy problems that will be acute by 2010 at the latest.

- **The region faces major problems in all parts of the energy infrastructure: gas pipelines, LNG facilities, electric transmission, power generation, smart systems for power management of the grid and of end uses.** As one example, New England's reliance on natural gas for electricity generation is a reliability issue for both electric and gas service. Over the past decade while gas prices were relatively low, the region's energy markets added new gas-fired power plants. Infrastructure limitations and other factors are forcing power generators to compete with gas utilities serving traditional gas consumers to obtain gas during peak winter demand periods. Aging infrastructure in the electric and gas system adds to these reliability risks. Meeting consumers' needs reliably and economically will require additional sources of gas supply and reinforcements to our natural gas pipeline and LNG delivery network. Similar pressures exist in other energy sectors.

- **New England needs to act aggressively to address its energy infrastructure challenges now.** Since most of the region's energy investments are made in private markets, investors respond to market signals. Right now, many signals coming from this region's market rules and regulatory policies present an uncertain investment climate at best – and at worst, send the message to take the investment dollars elsewhere. Shaping energy policy and developing energy infrastructure projects take time, so action is needed now to avoid problems in the near future. We see four factors – regional carbon policy, the federal and state rules governing the region's electric resource adequacy regime, and the willingness of various groups to embrace diverse new supplies – as being to a large extent within the control of actors in this region, and needing to be resolved soon. The sooner that these sources of risk and uncertainty in energy markets and policies are settled and resolved in a stable fashion, the sooner that investors can make decisions reflecting potential infrastructure investments in the region.

- **Energy efficiency should be a priority among many implemented options.** While the New England states have already made a substantial and on-going commitment to energy efficiency programs, we expect that the high energy costs this upcoming winter will lead to renewed interest in energy efficiency. This will be a market-based response to high prices. But additionally – in the interests of cost, efficiency, and health and environmental impacts – the region should aggressively expand its policies and programs to reduce electric and natural gas demand through economical conservation and demand response efforts. We expect this will need to occur along side of, not instead of, other energy infrastructure options.

- **There is no single answer to solving the region's energy needs**. A review of the combined policy, market, and economic factors affecting each potential solution to the region's infrastructure needs produces only one certainty: that there is no "silver bullet" solution. All potential contributors to reducing energy demand and increasing energy supply must continue to be considered in parallel; and most are likely to be needed to maintain reliability and mitigate gas and electricity price increases in a way that supports the region's environmental and quality-of-life objectives.

EXECUTIVE SUMMARY AND INTRODUCTION

The importance of energy Infrastructure: All aspects of everyday life in modern society rely upon infrastructure – from roads to hospitals to fire departments to schools to transportation systems. Health, public education, commerce, communications, and entertainment are made possible in part through the widespread availability of supporting infrastructure whose costs and benefits are spread widely across communities all over the country. This is a report on infrastructure of a particular type – the infrastructure needed to bring electricity and heat to homes and businesses – *energy* infrastructure – with a focus on New England.

Energy is on the verge of becoming a bad word in the 21st Century. In just the past five years, we have seen an energy market disaster (California); a massive electric system outage (the Northeast); an energy business scandal worthy of several books and a movie (Enron); manipulation of energy markets and price reporting data (the West); utility and other power company bankruptcies in several states; dramatic, and to some extent permanent, increases in gasoline, natural gas, electricity, and even coal prices; and growing certainty that the world's insatiable appetite for fossil fuel combustion is dangerously altering the global climate, with potentially severe consequences.

The geographic concentration of domestic energy supplies: Most recently, we have witnessed first hand the startling vulnerability of our nation's energy supplies to the geographic concentration of energy infrastructure. Our daily lives and the basic building blocks of commerce depend greatly on the availability and affordability of petroleum products, and our electricity generation depends heavily on the availability and affordability of natural gas. Not only are incremental oil supplies located in the hands of few producers located in countries known for their instability, but also, much of our domestic energy supply and delivery infrastructure is concentrated in a single region: the Gulf Coast. Within weeks of Hurricanes Katrina and Rita bearing down on the Gulf, wreaking havoc with the heart of the country's petroleum and natural gas infrastructure, we paid gasoline prices exceeding three dollars for the first time ever (eclipsing the previous inflation-adjusted high mark for the U.S.), oil was released from the strategic petroleum reserve, and the Energy Information Administration ("EIA") now projects that natural gas prices will exceed $10 per thousand cubic feet for the duration of the winter heating season – on the order of 50 percent higher than last winter.

In the aftermath of the exodus from Houston on the eve of Hurricane Rita, the *New York Times* put it this way:

> Consider: America's energy industry – both its oil supplies and refineries – is concentrated along the Gulf of Mexico. And it takes about 10 years to construct a refinery. That means gas prices will almost always spike each time a hurricane heads for the gulf coast. Already the gulf accounts for a third of America's oil and gas supplies, and that share is expected to grow. Few states have been willing to approve more oil drilling. Coastal states like Florida and California fear the oil industry would scare away tourism. And environmental opposition has so far stymied efforts to drill in Alaska's Arctic National Wildlife Refuge and the Rocky Mountains. The concentration in refining capacity is even more marked. There are 50 refineries in coastal states, and the refining capacity of Texas, Louisiana, Alabama and Mississippi is almost equal to that of the rest of the country. No new refineries have been built for nearly 30 years. Only one is being built, in Arizona, and it won't come on line for a decade. To meet demand, refiners have

> instead expanded their existing plants, particularly along the gulf coast…. [F]or Lawrence J. Goldstein, president of the Petroleum Industry Research Foundation, the recent hurricanes make the industry's case for expanding beyond the gulf. "Our facilities have been forced into a natural disaster corridor," he said.[1]

New England feels the brunt of energy disruptions: In spite of its distance from the Gulf Coast, New England is regularly hard hit by stresses on energy supply and delivery infrastructure, wherever they occur in the U.S. New England is literally at the end of the country's natural gas pipeline network, has no oil refineries located in the region, is twice as dependent on oil for heating homes as the rest of the nation, and has relied almost exclusively on natural gas facilities for newly-built electric generating capacity in the past decade. Five of the six New England states are among the nation's eight most expensive states from an energy price and expenditure point of view. New England consumers thus feel the brunt of supply disruptions and their impacts on energy prices.

These impacts are amplified by in-region deficiencies in energy infrastructure. This occurs, for example, in areas where inadequate transmission capacity restricts the flow of electric power from lower-cost generation to consumers in high-density load pockets. Some of these sub-regions themselves are excessively dependent on – and thus vulnerable to disruptions in – natural gas for heating and electricity generation. The efficient functioning of our region's restructured electric industry depends in part upon adequate energy infrastructure – whether generating capacity, transmission capacity, fuel delivery capacity, or software for monitoring and managing demand.

New England needs new electric and gas infrastructure: Except for wind, some other local renewable resources and some opportunities to "mine" inefficient uses of energy locally, New England is a region with virtually no indigenous energy resources. Relying heavily on traditional fossil-fuel supply sources delivered from distant locations, we are acutely aware of how the region's way of life and its economy depend on adequate and diverse energy infrastructure. And we are at a critical point in our need to strengthen it. For example, it is clear that New England must reinforce its electric generation and transmission infrastructure starting immediately to be able to meet region-wide electric reliability requirements a few years from now.

New England's reliance on natural gas for electricity generation is a reliability issue for both electricity and gas service in the region, given today's infrastructure. Over the past decade while gas prices were relatively low, the region's energy markets gravitated toward adding new gas-fired power plants, which added gas demands on top of the growing heating and process needs of residential and commercial/industrial customers. Infrastructure limitations and other factors are forcing power generators to compete with gas utilities serving traditional gas consumers to obtain gas during peak winter demand periods. Meeting these needs reliably and economically will require additional sources of gas supply and reinforcements to our natural gas pipeline and liquefied natural gas ("LNG") delivery network. A recent study for the New England Governors' Conference projects that winter peak gas demand will exceed supply within 5 years. Many other analyses, including our own, think that this is likely to occur even sooner.

New infrastructure can support reliability and market objectives: One of the strengths of New England's energy systems is the long-standing platform of regional cooperation and

[1] Donald G. McNeil, Jr., "Imagine 20 Years of This," *New York Times*, Week in Review Section, September 25, 2005.

integration. Electric systems and gas pipelines cross state boundaries. The grid has operated reliably on a New-England-wide basis for four decades. Power plants and gas systems in one state are relied upon to serve customers in another, on a day-to-day basis and particularly in times of emergency.

The physical energy systems in the region are highly integrated, at the same time that the investment in and ownership of the majority of energy assets in New England is split among many market participants. Utilities have retained ownership over most of the electric and gas transmission and distribution network infrastructure in the region, but recent federal and state initiatives to restructure energy industries have diversified the ownership and operation of most of the sources of fuel and power generation that is delivered to consumers over these utility networks. Retail consumers in New England rely on competitive wholesale markets to provide their power supplies, whether those consumers purchase power directly from non-utility suppliers or indirectly through their utilities who must also purchase supply in the competitive markets. Over the past ten years, much of the construction of major interstate gas transportation infrastructure and new electric generating capacity, and the investment risks associated with such investment, have been born by private energy companies and investors, while the prices charged for gas and electricity generation have been disciplined by competitive market forces.

Yet the future performance of our region's competitive market structure is dependent on the availability of adequate infrastructure. Energy market competition requires adequate generation capacity. Generation capacity is not economic as a regional resource without adequate transmission infrastructure. And the continued viability and cost-competitiveness of new efficient gas-fired capacity throughout the year, and in particular during winter and summer peak seasons, will require additional natural gas supply and delivery infrastructure. In 2004, power plants using only gas or which can use either oil or gas set the market clearing price for power *85 percent of the time*. Not surprisingly, wholesale prices of electricity closely track variations in the price of its marginal fuels – natural gas and oil.

Energy policy and infrastructure development take time, so action is needed now to avoid problems in the near future. The time to address New England's looming needs for additional energy infrastructure is immediate, in order for the region to reliably meet expected growth in consumers' heating and electricity needs. Implementing solutions takes time and effort. The degree of time and effort – like the type of energy options pursued – is driven by public policy and market signals. Major energy infrastructure requires careful consideration of human health, safety and environmental risks. Poor choices – and even good ones – about energy projects can lead to stiff public and political resistance. Certain of these risks stand out. For example, from the standpoint of long-term energy policy, one of the key factors affecting investment decisions on energy infrastructure is the still-uncertain governmental policy on reducing greenhouse gas emissions. Other key factors are the local health and safety risks of proposed projects, and the reaction to these risks in the communities in which they would be located. The added influence of investment incentives and changing regulatory authorities in the new federal Energy Policy Act is currently unfolding. In the electric sector in New England, the evolution of these policy-driven development considerations is combined with disagreement over the future of key market structures governing the value of generating capacity. This combination of traditional development challenges and market structure uncertainty threaten to stifle needed infrastructure development over the next several years. Concerted action is needed to resolve these issues sooner rather than later.

There is no single answer to solving the region's energy needs: A review of the combined policy, market, and economic factors affecting each potential solution to the region's infrastructure needs produces only one certainty: that there is no "silver bullet" solution. All potential contributors to reducing energy demand and increasing energy supply must continue to be considered in parallel; and most are likely to be needed to maintain reliability and mitigate gas and electricity price increases.

There is a clear need for new energy resources, and every one involves trade-offs of one sort or another. Some involve high capital costs but offer stable fuel prices; others are cheap to build but have high fuel costs, which may be sensible if the need is for quick-start resources that operate only rarely. Some have (positive or negative) impacts not reflected in prices, and therefore markets tend to under or over supply them. Relying on policy "carrots" to create incentives for certain types of energy resource developments may run afoul of the wants and desires of local communities to which those development projects gravitate. Relying strictly on markets without placing a value on diversity or environmental impacts of different supply types may lead to investment in a narrow set of options. There are virtually no energy options that satisfy all objectives all the time and in every place. This calls for keeping all energy options open, and striving to recognize in the review of policy and investment proposals the broad regional (and national) dispersion of the benefits and costs that come with energy infrastructure development.

In our view, the existence of various potential energy development risks and trade-offs – from fundamental questions of maintaining reliability and economic growth, to addressing potential health and environmental impacts affecting local communities, to the risks of global climate change – suggests that first on the list of regional energy priorities should be a concentrated and aggressive ramping up of efforts to reduce demand through a combination of approaches: fuel efficiency standards, appliance efficiency standards, aggressive building codes, energy conservation installations, and demand-response market mechanisms at the wholesale and retail levels. This winter's expected high energy prices are likely to give rise to market-driven responses, in addition to an active partnership of government and private interests. These actions should occur on an urgent time frame in order to find not only cost-effective local solutions, but also to lessen the adverse impacts of any continuing uncertainties regarding other government policies.

More aggressive demand-side approaches are necessary, but we do not assume they will be sufficient to meet all of our energy needs over the next ten years.[2] New England also needs additional energy infrastructure – that is, electric generation and transmission facilities, and additional sources of and delivery systems for natural gas. In light of this, it would be prudent to keep all of these options on the table, and resolve critical policy uncertainties as soon as possible.

Trade-offs: planning for outcomes, versus allowing markets to determine outcomes. One of the hallmarks of New England's energy markets in 2005 is its reliance on markets. Few other parts of the nation have the same degree and combination of centrally-organized wholesale markets, generation divestiture, diversity and number of market participants, retail access policies, and an increasing number of consumers whose prices for electric power are determined

[2] There are estimates of demand-side economic potential that match or exceed expected growth in electricity demand over the next several years. See, e.g., Northeast Energy Efficiency Partnerships, Inc. ("NEEP"), *Economically Achievable Energy Efficiency Potential in New England*, prepared by Optimal Energy, Inc., Updated Spring 2005. While we think it reasonable to expect that this winter's high energy prices in New England will bring about more aggressive demand-side actions (in terms of energy efficiency investments and simply less energy use) than seen in recent years, we do not think that historical experience with implementation of demand-side management within the region supports the conclusion that within this time period – i.e., the next several years – demand-side resources sufficient to meet future needs can proceed through policy development, funding, administration, and installation, or will result in levels of performance in line with expectations.

either directly or indirectly through competitive markets. Private investors and lenders put $6 billion into the region, and brought over 9,000 MW of new power plant capacity into commercial operation in the past decade.[3] With almost no exceptions, these investors chose to invest exclusively in combined-cycle natural gas technologies, as a result of various market signals (including, e.g., then-low gas price curves, relatively high efficient and proven power generation technology, relatively low capital cost, proven financing models, proven contracting regimes for sharing risks among power developers and their equipment suppliers for these particular technologies, newly-opened power markets, strict air pollution control standards) and public policy objectives (e.g., merchant investment, regional air quality improvement). One of the consequences of this particular pattern of market-driven investment is the region's new and heavy reliance on natural gas for power generation. One of the advantages of markets is that results spring from the decisions of countless suppliers and consumers, each trying to satisfy his or her own objectives and needs, without the need for prescriptive policies of state and federal government. Yet these market decisions can also produce the kind of "unintended" results we see today: that is, a region highly dependent upon a single fuel with unexpectedly high prices.

This outcome reveals an inherent tension between the broadly supported policy goal of relying on competitive power markets to drive resource investment and an increasing call for diverse, affordable set of electric resources, involving a mix of fuels, technologies, sizes, and environmental characteristics. This would suggest that power markets in the region may not provide adequate incentives for resources with certain social-value attributes (e.g., diversity of power options, peaking/reserve resources, stable fuel prices, low-carbon emission profiles).[4] If this is the case, it is no surprise that private power markets underproduce resources with these characteristics.

This tension – between market-driven outcomes and policy goals related to power system resource mix characteristics – is neither new nor unique to New England. But the potential delays in and barriers to investment in infrastructure it creates threatens to undermine the adequacy of resources in our region. Therefore, policy makers in the region should reflect as soon as possible on the objectives they want to see for the region, and on what combination of market structures and policy mechanisms and incentives will most likely meet these resource mix objectives.

Our conclusions and recommendations. In this report, we focus on two topics related to these issues: expectations for the supply and demand in New England for electricity and natural gas; and the national and regional energy and environmental policy context for the siting of additional infrastructure to meet the region's energy needs.

First, we analyze recent publications in the region that identify the resources needed to meet electricity and natural gas demand reliably and economically over at least the next decade. Next, we discuss the critical energy and environmental policy factors that we believe will be considered in shaping the near-term development of our region's energy infrastructure, including recent federal energy legislation, climate change, and electricity market structures.

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[3] ISO-NE, "Delivering Value to the Region," 2005.

[4] For example, a lack of appropriate incentives for investment in long-term capacity under current retail and wholesale market rules has been identified as one reason why investors are not currently interested in developing new power supply projects for New England. This situation arises, in large part, as a combination of problems in the structure of the ISO-NE's capacity markets (as pointed out by the Federal Energy Regulatory Commission), the short-term nature of retail supply procurements for standard-offer customers, and the relatively short-term contracting terms of competitive suppliers.

Executive Summary and Introduction

Based on our review, we provide the following observations and recommendations about actions and policies needed to move our region forward to a future of secure and environmentally-appropriate energy policy and infrastructure:

1. **The need to begin development of new energy resources is upon us now.** New England's existing electricity and natural gas infrastructure will be inadequate to reliably meet the region's demand within the next several years. Current resources will be insufficient to maintain the reliability of the electric grid in parts of New England as soon as 2008. Even by next year, current resources could be insufficient to meet Northeast Power Coordinating Council reliability criteria during high-load hours without resorting to Operating Procedure 4 ("OP 4") actions on a more than occasional basis. From a cost perspective, there is an immediate need for quick-start generation in certain sub regions to lessen or eliminate the commitment of uneconomic generation. Similarly, our review of estimates of demand for natural gas during winter peaks reveals potential supply/delivery shortages as soon as 2007 without additional gas supply sources and delivery capacity. *In short, plausible scenarios of demand exceeding available supplies and delivery capacity for both electricity and natural gas occur as soon as within the next two years, and the need for additional supplies may already be upon us*[5]. Even considering that need could arise in later years under more optimistic assumptions about capacity availability or weather conditions, given that major new policies and major infrastructure development both take several years to be implemented and effective, action is needed now.

2. **Uncertainties affecting energy markets are chilling investment.** Factors that will influence regional infrastructure decisions include (a) expectations for short-term and long-term energy prices, (b) various structural and financial incentives contained in the recently passed federal energy legislation, (c) expectations regarding the timing and design of a future regime in the region and/or the U.S. for addressing the risks of climate change, (d) the resolution of uncertainties surrounding the form of long-term market signals to spur investment in electric generating capacity in New England, (e) state policies affecting procurement of long-term energy resources on behalf of retail consumers, and (f) community acceptance of different types of energy projects. All of these affect the willingness of investors to back projects and make long-term commitments to supply. The latter four factors – regional carbon policy, the federal and state rules governing the region's electric resource adequacy regime, and the willingness of various groups to embrace diverse new supplies – are to a large extent within the control of actors in this region. The sooner that these sources of risk and uncertainty in energy markets are settled and resolved in a stable fashion, the sooner that investors can make decisions reflecting their views of future energy prices and the opportunities created by the new federal Energy Policy Act of 2005.

3. **Energy efficiency should be a priority among many needed options.** While the New England states have already made a substantial and on-going commitment to

[5] See the discussion below regarding the ISO-New England's most recent assessment of winter 2005/2006 conditions in New England in the post-Hurricane period. This assessment indicates a tighter capacity outlook than previously expected, in light of the more constrained outlook for natural gas supplies during the winter of 2004/2005 than previously expected.

energy efficiency programs,[6] we expect that the high energy costs this upcoming winter will lead to renewed interest in energy efficiency. This will be a market-based response to high prices. But additionally – in the interests of cost, efficiency, and health and environmental impacts – the region should aggressively expand its policies and programs to reduce electric and natural gas demand through conservation and demand response efforts. This includes more aggressive programs sponsored by electric and gas distribution utilities (and supported by "system benefit charges"); enhanced building and appliance efficiency standards adopted by states in the region; improved retail pricing options for consumers that make more visible the costs of supplying energy at different times of day and different times of year; and the concentrated expansion of demand response programs implemented in wholesale and retail electricity markets in New England. Saying that this will and should occur does not mean, however, that additional supplies are not needed.

4. **Incremental gas supply and delivery capability is essential.** Both electric and gas consumers need increased winter peak-season supply and delivery capacity for natural gas in New England. Declining production of, and increasing competition for, continental gas supplies in the U.S. and Canada mean that imports of LNG may be the most economic and reliable option available to our region. In addition to increased LNG import capacity, enhancements are needed in the region's inter- and intra-state pipeline delivery networks. Additional gas supplies can improve the reliability and economics of New England's reliance on gas for heating, electricity generation, and commercial/industrial process needs. It can also reduce the stresses on electric system reliability associated with our dependence on gas-fired generation.

5. **New electric transmission investment will help reliability and competitive wholesale markets.** There are substantial economic and reliability impacts associated with deficiencies in the region's network of electric transmission facilities. Timely completion of the major 345 kV projects still in the siting process or under construction in the region will provide significant relief from these impacts. Additional enhancements to the region's transmission system infrastructure can provide additional economic and reliability benefits.

6. **The region needs to support actual renewable projects, not just pro-renewables policies.** Many of the states within New England have adopted policies aimed at increasing the development of and reliance upon new renewable resources to meet growing electrical demand. This has taken many forms, including renewable portfolio standards and enhanced financial funding programs and incentives. In some states, these programs are beginning to induce development proposals. One challenge going forward will be to make sure that when developers respond to these public policy "carrots," that there is appropriate follow-through with permitting of sound projects. The

[6] According to the Northeast Energy Efficiency Partnership, consumers in the six New England states supported $265 million in energy efficiency programs in 2005: Connecticut = $62 million/year; Massachusetts = $135 million/year; Maine = $11 million/year; New Hampshire = $18 million/year; Rhode Island = $22 million/year; and Vermont = $17 million/year. NEEP, "Ratepayer Funded Energy Efficiency Programs Northeast States 2005 – Gas & Electric." Energy savings from these energy efficiency programs were estimated by NEEP to amount to 822,589 MWH in 2005. NEEP, "Annualized Electric Efficiency Program Savings (MWh) at Generation Level for New England." ISO-NE estimates that ratepayer-supported/utility-sponsored demand-side programs accounted for 1,552 MW during the 2005 summer peak and approximately 7,909 GWH of avoided generation. IS0-NE, Draft Regional System Plan 2005, page 35.

region should not just support renewables in policy, but also in fact. It must also allow the siting of needed and sound renewable projects in current development, particularly those large enough to make a significant near-term contribution to energy supply. Renewable projects, based on sound environmental reviews and long-term investment support, will provide fuel diversity, security, economic and environmental benefits, many of which are not captured in prices and traditional economic analyses.

7. **New England's energy costs are comparatively high.** The region's energy mix is different than the rest of the country, with some interesting implications. Compared to the nation as a whole, New England has more electric power production from nuclear power and natural gas, and far less from coal and hydropower and other renewables. This means that only a portion of the region's electric power is based on "stable priced" fuels, such as hydroelectric, renewables, coal and nuclear. The benefits of fuels with "stable" prices are typically realized in long-term bilateral contracts. But in New England, much of the power from these sources is priced in the ISO-NE's spot markets according to the spot price of power – which is typically tied to gas and oil. These fuels have more volatile prices, which are increasingly set in global markets as the nation moves to importing a significant share of its gas resources in addition to being reliant on imported oil. Even though the stable-fuel-priced generating resources have provided some consumer benefits, overall the region still pays among the nation's highest energy prices. Of the eight states with the highest consumer energy prices in the nation, five are in New England. Prudent energy planning should consider the potential impacts and trade-offs (e.g., among fuel diversity, cost, environmental impact, reliability issues) of future retirement/attrition of the region's existing baseload, stable fuel price resources, and how to maintain price stability and fuel diversity, along with environmental progress, under these circumstances.

8. **There are no silver bullets for meeting New England's near-term energy needs.** Future solutions to growth in energy demand in the region will emerge from a patchwork quilt of state and federal policy, economics, technology development, and prevailing market and regulatory structures. This will occur against a backdrop of growing tension between the need for energy infrastructure to meet public and commercial needs on the one hand, and the increasing unwillingness of the public to accept the construction and operation of large infrastructure projects – of any sort – in their local communities. Unfortunately, New England faces a growing need for reliable and diverse electricity and natural gas supplies, without a simple or definitive single solution to address these needs. In fact, strict reliance on markets may not solve the diversity problem, since markets do not pre-determine resource mix outcomes. Energy planners, policymakers and developers within the region thus need to keep open and carefully evaluate the tradeoffs represented by all demand and supply options available. We urge a broad recognition that a diverse mix of energy policies and infrastructure is needed, with clear attention to the issues of safety, fuel diversity and environmental impacts where appropriate.

NEW ENGLAND ELECTRIC AND GAS SECTOR SUPPLY AND DEMAND

OVERVIEW

Our discussion of New England's gas and electric needs starts with a description of the results of major demand and supply forecasting efforts performed by others in the region.

On the electric side, New England has operated as an integrated electric grid since the 1970s, with coordination of long-term planning and real-time bulk power system operations to maintain electric system reliability and economic dispatch for the region. Through June 1997, the New England Power Pool ("NEPOOL") coordinated system operations of the electric utilities' systems in the six New England states. Since July 1997, system operation and long-range planning have been the responsibility of the New England Independent System Operator ("ISO-NE," or "ISO"). Under regulatory supervision by the Federal Energy Regulatory Commission ("FERC"), ISO-NE is responsible for managing the operations of New England's bulk power generation and transmission system, overseeing and administering the region's wholesale electricity markets, and managing the regional bulk power system planning process.[7] Individual power companies, transmission and distribution utilities and others provide the resources needed to supply electric customers' needs. In this context, ISO periodically prepares and issues a comprehensive assessment of New England's electric system demands and needs, and its most recent assessment is reviewed in this section.

On the natural gas side, there is no regional equivalent of the ISO-NE. This is in part due to fundamental differences between electric and gas production and delivery systems, product storage capability, and market and regulatory contexts. A variety of gas companies move gas from primarily distant supply sources and storage facilities, through a series of interstate pipelines and local distribution systems, to consumers' burner tips. Most of these consumers take gas on a firm-supply basis from the local distribution company ("LDC"). Large customers (such as power plant owners or operators) sometimes take "interruptible" or non-firm service from the LDC, or take service directly off the interstate pipeline. Forecasts of regional customer demand are therefore complicated by these factors. LDC forecasts of the gas requirements of their firm customers must be combined with other demand estimates to capture the full picture of future gas customers' needs.

To provide these perspectives on electricity demand and supply, we draw on the work of ISO-NE. For the regional natural gas outlook, we review expectations for natural gas supply and demand in a number of regional/national studies, and review in particular a comprehensive supply & demand analysis recently completed by the Power Planning Committee of the New England Governors' Conference ("NEGC").

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[7] ISO New England, Inc., *Draft Regional System Plan 2005*, last revised September 2, 2005 (hereafter "Draft RSP 05"), at ES-2. For more information on the ISO, see www.iso-ne.com.

Supply and Demand: Electric and Gas

ELECTRICITY

The ISO-NE's Forecast of Supply and Demand in New England

ISO-NE annually carries out a comprehensive 10-year assessment of the New England regional system-wide needs for generation and transmission – the Regional System Plan, or "RSP" ("RSP 05" for the current-year Plan). Using its operational knowledge of the bulk power system, ISO-NE simulates system operation over time. ISO prepares region-wide and localized forecasts of electric energy demand, peak load and system reserve requirements, and system generation and transmission infrastructure. In addition to its own analysis, the ISO consults extensively with government agencies, utilities and other electricity market stakeholders, along with the system operators of neighboring U.S. and Canadian regions, in developing its long-term regional plan.

Draft RSP 05 contains forecasts of peak load and energy use for New England for the period 2005 to 2014, including "50/50" and "90/10" peak loads.[8] The "50/50" forecast peak load has a 50 percent chance of over-estimating demand and a 50 percent chance of under-estimating demand (i.e., where demand exceeds projections). The "90/10" forecast has a 10 percent chance of being exceeded.[9] Using forecast and system data, Draft RSP 05 conducts several reliability-related analyses to determine the system and sub-regional generation and transmission infrastructure needs over the planning horizon, and to review the impact of certain key model factors such as fuel mix and environmental constraints.

ISO-NE's RSP is by far the most extensive and authoritative representation of the region's current electric system as it exists today, as well as its conditions in the future based on reasonably likely developments on the horizon. As such, it provides an important tool for understanding the need for electricity infrastructure in New England over the next ten years, as well as some of the most important factors that can or do affect New England electric system reliability.

The snapshot of our regional electricity system presented by ISO-NE shows the following picture of demand and supply for New England:[10]

- *Peak Load* – The summer peak load (preliminary) in 2005 was 26,749 MW, 5.5 percent higher than the previous all-time peak load for the region;

- *Projected Peak Load* – Summertime peak load in New England is estimated to increase by approximately 15% over the next ten years, after accounting for a reduction of about 1,600 megawatts ("MW") due to the effects of existing utility energy conservation programs (see Table 1 and Figure 1 below).

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[8] The last completed review of electric system infrastructure and projections of future supply and demand for the region was contained in the ISO's last "Regional Transmission Expansion Plan," for 2004 ("RTEP 2004"). The current RSP process replaces and supplements the regional infrastructure analysis contained in the previous RTEP reports. While the most recent RSP document is only a near-final draft of RSP 05, it contains significant updates to the supply and demand forecast information contained in RTEP 04, and has been largely vetted through regional stakeholder review processes. For this reason, and in the interest of using the most current data and information possible, we rely on the Draft RSP 05 document in this report, even though it has not yet been issued in final form.

[9] Draft RSP 05, page ES-4.

[10] Draft RSP 05, pages ES-7 – ES 11.

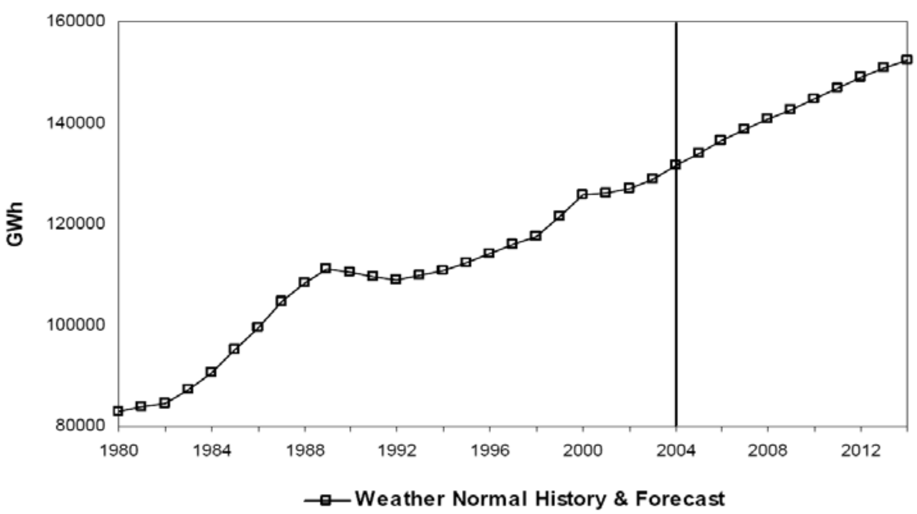
Table 1 [11]

Energy and Peak-Load Forecast Summary for the ISO New England Control Area and States, Net Energy for Load (GWh)

	Net Energy for Load (GWh)			Summer Peak Loads (MW)					Winter Peak Loads (MW)				
				50/50		90/10			50/50		90/10		
Area	2005	2014	CAGR	2005	2014	2005	2014	CAGR	2005/06	2014/15	2005/06	2014/15	CAGR
NE Control Area	134,085	152,505	1.4	26,355	30,180	27,985	32,050	1.5	22,830	26,005	23,740	27,030	1.5
CT	34,620	40,500	1.8	7,125	8,305	7,580	8,835	1.7	6,025	6,990	6,285	7,290	1.7
ME	12,140	13,790	1.4	1,975	2,255	2,060	2,355	1.5	1,960	2,220	2,010	2,270	1.4
MA	60,590	67,430	1.2	12,110	13,660	12,845	14,485	1.3	10,340	11,600	10,780	12,080	1.3
NH	11,840	13,990	1.9	2,300	2,720	2,490	2,950	1.9	2,040	2,400	2,125	2,500	1.8
RI	8,525	9,760	1.5	1,805	2,075	1,920	2,205	1.6	1,435	1,660	1,490	1,720	1.6
VT	6,375	7,035	1.1	1,045	1,175	1,100	1,235	1.3	1,030	1,150	1,060	1,180	1.2

Note: "CAGR" is compound annual growth rate.

Figure 1 [12]
Projected Peak Load – New England



- *Region-Wide Capacity Assessment* – Current total New England resource capacity is barely sufficient to meet the Northeast Power Coordinating Council's reliability criterion of not disconnecting firm load due to insufficient resources more than one day in ten years (the

[11] Excerpted from Draft RSP 05, Table 3.1.
[12] Excerpted from Draft RSP 05, Figure 3.2.

"loss of load expectation," or "LOLE" criterion).[13] This means that as load grows, the region will need to operate under Operating Procedure 4 ("OP 4") with increasing frequency during high-demand hours.[14,15] Even assuming the ability to rely on OP 4 actions, New England is projected to need an additional 170 MW of generating capacity by 2010 to meet the LOLE criterion, as shown in Table 2 below.[16]

Table 2 [17]

Cumulative Capacity Needed in New England
to Meet One-Day-in-10-Year LOLE (MW)

Year	0 MW Tie Benefits	1,000 MW Tie Benefits	2,000 MW Tie Benefits
2005	0.0	0.0	0.0
2006	172.5	0.0	0.0
2007	690.0	0.0	0.0
2008	1,035.0	0.0	0.0
2009	1,897.5	690.0	0.0
2010	2,415.0	1,207.5	172.5
2011	2,932.5	1,897.5	690.0
2012	3,450.0	2,415.0	1,380.0
2013	3,967.5	2,760.0	1,725.0
2014	4,312.5	3,277.5	2,070.0

[13] The assessment of capacity adequacy under the LOLE criterion is a region-wide probability-based analysis incorporating weekday peak load levels and generator forced outage expectations; it does not take into account transmission system constraints or real-time operational contingencies that restrict the actual flow of power within the region under peak load conditions. See Draft RSP 05, Section 2.3.1.1.

[14] Draft RSP 05, page ES-9. OP 4 (officially known as *Action during a Capacity Deficiency)* is a set of operating procedures followed by ISO-NE and the region's utilities when available capacity is nearly insufficient to meet peak load conditions. Under OP 4 conditions, the system operator must take special steps to prevent curtailment of firm customer load. These actions include reducing operating reserves, reducing voltages, importing emergency power, activating emergency demand response to make capacity available, and taking other emergency measures while still maintaining transmission system reliability. See <http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html>. Draft RSP 05, page 1. The ISO notes that while operation under OP 4 conditions is consistent with resource planning criteria, "…it serves as a strong warming signal that additional resources are needed in the near future." Draft RSP 05, page 19.

[15] ISO-NE has implemented OP 4 Actions with different frequency in past years, and in large part as a function of the level of installed reserves in the region. In 1999, before the completion of most of the new generating resources added since the early 1990s, OP 4 actions were implemented 11 times. As significantly more capacity was added in 2000 through 2003, the frequency of OP 4 implementation dropped, from 6 events in 2000 to 2 events in 2003. There were two events in the winter of 2003/04, one in the summer of 2004, one in the winter of 2004/05, and twice in the summer of 2005. http://www.iso-ne.com/sys_ops/op4_action_archiv/2005/index.html

[16] In Table 2, "Tie Benefits" refers to the ISO-NE's estimate of the reliability value for New England of the "emergency assistance assumed to be available from the neighboring systems [e.g., Canada]. These emergency tie-reliability benefits account for both the transmission-transfer capability constraint of the tie lines, as well as the capacity that may be available from the neighboring systems at the time of need in New England." Draft RSP 05, page 37.

[17] Excerpted from Draft RSP 05, Table 4.1.

- *Load Pocket Operable Capacity and Operating Reserve Assessment* – The region-wide capacity assessment described above depicts the overall conditions for New England, without taking into account the effects of transmission and other operating constraints that exist within the region. To create the picture of real-time operating conditions within New England, it is necessary to model transmission-system physical constraints or operational restrictions that are required to maintain safe and reliable operation of the system at all times and in all parts of the region. Consequently, ISO-NE models these conditions using assumptions typical of the annual peak day over the forecast period. This identifies places where additional capacity (e.g., additional generation capacity and/or transmission system upgrades) is needed to maintain grid reliability under peak load conditions. Draft RSP 05 identifies the following needs based on these analyses:
  - There is an immediate need for over 500 MW of quick-start generating resources in both Connecticut and the greater Boston area, to reduce the commitment of uneconomic generation and to provide operating reserves in those regions.[18]
  - Operable capacity requirements will require that New England either add new generating capacity or rely on OP 4 actions at levels in 2008 that range from 160 MW under the 50/50 forecast to 1,900 MW under 90/10 forecast conditions (see Tables 3 and 4 below).

Table 3 [19]

Projected New England Capacity, Summer 2006–2014, Using 50/50 Loads (MW)

Capacity Situation (Summer MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014
Load (50/50 forecast)	26,970	27,350	27,750	28,145	28,565	29,050	29,500	29,845	30,180
Operating reserves	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700
Total Requirement	28,670	29,050	29,450	29,845	30,265	30,750	31,200	31,545	31,880
Capacity	31,393	31,393	31,393	31,393	31,386	31,386	31,386	31,386	31,386
Assumed unavailable capacity	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100
Total Net Capacity	29,293	29,293	29,293	29,293	29,286	29,286	29,286	29,286	29,286
Available Surplus/(Deficiency)	**623**	**243**	**(157)**	**(552)**	**(979)**	**(1,464)**	**(1,914)**	**(2,259)**	**(2,594)**

[18] Reliability-based operating procedures require that across the region, and within each transmission-constrained sub region, there be sufficient resources ("operating reserves") available within a short period of time (ten to thirty minutes) to at least cover the contingency that the largest source of power is lost, e.g., due to generator shut down or loss of a major transmission line. In Connecticut and Boston, there is not currently enough quick-start generation to meet operating reserve requirements during high-load conditions. As a result, higher-cost resources are often dispatched to minimum load levels to provide the level of operating reserves required.

[19] Excerpted from Draft RSP 05, Table 4.2.

Table 4 [20]

Projected New England Capacity Situation, Summer 2006–2014, Using 90/10 Loads (MW)

Capacity Situation (Summer MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014
Load (90/10 forecast)	28,660	29,070	29,495	29,910	30,350	30,860	31,330	31,700	32,050
Operating reserves	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700
Total Requirement	30,360	30,770	31,195	31,610	32,050	32,560	33,030	33,400	33,750
Capacity	31,393	31,393	31,393	31,393	31,386	31,386	31,386	31,386	31,386
Assumed unavailable capacity	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100
Total Net Capacity	29,293	29,293	29,293	29,293	29,286	29,286	29,286	29,286	29,286
Available Surplus/(Deficiency)	(1,067)	(1,477)	(1,902)	(2,317)	(2,764)	(3,274)	(3,744)	(4,114)	(4,464)

- *Long-Term Combined Capacity Analyses* – According to the ISO, when the results of the capacity and operating reserve analyses are viewed together, they "…demonstrate that New England likely will face an increased risk of operating with less capacity than needed by 2008… Because the timeframe for building new generation resources is about two to four years, the analysis highlights the urgent need for new generating resources in New England."[21]

- *Short-Term Outlook* – ISO-NE has recently assessed the electric system capacity outlook for the winter of 2005/2006, in light of the conditions in domestic oil and gas markets following Hurricanes Katrina and Rita. Because of newly anticipated shortages in natural gas commodity supplies, this short-term winter assessment shows a bleaker picture for New England than previous anticipated. For example, ISO-NE now anticipates that there may not be enough gas-fired power plants able or willing to operate to meet electric peak demands this winter.[22] ISO-NE anticipates that, since (a) so much gas-fired capacity (7,200 MW) was found to be out of service during cold-snap conditions last winter, and (b) a significant share (25%) of New England's gas supplies come from the Hurricane-stricken Gulf Coast, there is a good chance that a significant share of gas-fired capacity will be out of service during the upcoming winter due to unavailability of gas supplies. Also, because of expected supply constraints this winter in combination with the incentives that gas-fired generators have to use gas in the most economical way (e.g., generating electricity versus selling gas to the utilities serving the traditional gas market), there is little financial incentive for them to generate electricity with gas. This may create shortages in the electric system resource base – at a time when electricity demand is actually estimated to grow. This situation is reflected in Table 5, which is ISO-NE's outlook for "Operable Capacity" in New England for a peak period during winter 2005/2006. While the ISO has identified a number of emergency strategies to mitigate these problems, the bottom line is that the reliability of region's electric grid this winter is dependent upon natural gas supplies being available to the region's gas-fired generators.

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[20] Excerpted from Draft RSP 05, Table 4.3.
[21] Draft RSP 05, page ES-9.
[22] ISO-NE, Winter Assessment 2005/2006 Assessment and Action Plan: Preparing for Cold Weather Reliability," October 6, 2005.

Table 5[23]

Winter Peak Operable Capacity Analysis

Units: Megawatts (MW)	Winter Outlook 05/06 Pre-Katrina	Impacts to Winter Outlook from Katrina (Gas supply at 90% of pipeline capability with LDC buyback)	Impacts to Winter Outlook from Katrina (all Gas-only units Out of service)
Total Capacity	32,940*	32,940*	32,940*
Gas Unit Outages	5,700**	7,800	8,700
Other Unit Outages	1,700	1,700	1,700
Net Available Resources	25,540	23,440	22,540
Peak Load	23,740	24,140***	24,140***
Reserve Requirement	1,700	1,700	1,700
Operable Capacity Margin	100	-2,400	-3,300

* Includes 900 MW of ICAP Sales to NY (currently 640 MW scheduled)
** Assumes only 3,000 MW of the 8,700 MW of gas-only generation has firm pipeline transportation contracts
*** Includes increase in 90/10 peak load due to increase in electric heating load (400 MW)

- *Short-Term Contingency Plan* – ISO-NE's contingency plan for the upcoming winter includes: various operating procedures (400 MW); various public appeals for voluntary energy conservation (250-500 MW); actions by various gas-fired generators to extend the amount of time or their technological capability to burn oil in addition to natural gas (200-1000 MW); more aggressive demand-side management or price-responsive demand efforts (100-600 MW); and several emergency actions, including emergency imports of power (300-800 MW); and reductions in system voltages (250-300 MW).[24]

- *Fuel Diversity* – Virtually all of the new power plants added in New England in recent years has been gas-fired generating capacity. (See Table 6.) This has increased New England's dependency on natural gas for power generation. During the winter of 2004-2005, high natural gas demand (in non-electric sectors) contributed to the unavailability of electric generating capacity, and OP 4 actions were required to prevent the shedding of firm electric load. In Draft RSP 05, the ISO reviewed the region's dependence on natural gas for electricity generation, concluding that in order to avoid electric reliability problems during the winter, the region must convert to dual-fuel capability (or enter into an equivalent amount of firm gas supply and delivery contracts) approximately 400 MW of gas-fired generation by winter 2006/2007, by 250 MW each of the next two years, and by 500 MW for 2009/2010. ISO-NE sees the need to address this issue as particularly acute in the Boston sub region. The ISO notes that this dependence on natural gas suggests that the region's electric system reliability would improve substantially with the development of additional natural gas supply (e.g., LNG) and delivery infrastructure, and/or additional non-gas resources such as energy conservation/demand response, renewable, coal or nuclear generation capacity.[25] (See Figures 2 and Table 6 below).

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[23] Excerpted from ISO-NE, 2005/2006 Winter Assessment.
[24] From ISO-NE, 2005/2006 Winter Assessment.
[25] Draft RSP 05, pages ES-9 – ES-10.

Table 6 [26]
Number of Generating Units in New England by Fuel Type and In-Service Dates, Summer 2005

Fuel Type	In-Service Date Prior to 1950 # of Units	In-Service Date Prior to 1950 MW	In-Service Date 1951 to 1970 # of Units	In-Service Date 1951 to 1970 MW	In-Service Date 1971 to 1990 # of Units	In-Service Date 1971 to 1990 MW	In-Service Date 1991 and After # of Units	In-Service Date 1991 and After MW	Total MW	Total Percent
Gas	0	0	0	0	0	0	24	6,378	6,378	20.6%
Dual fuel[(b)]	3	63	4	354	9	336	27	4,805	5,558	18.0%
Oil	7	26	63	2,486	32	4,966	7	60	7,538	24.4%
Nuclear	0	0	0	0	5	4,387	0	0	4,387	14.2%
Coal	0	0	14	2,592	2	256	0	0	2,848	9.2%
Pumped storage	1	29	0	0	3	1,643	0	0	1,672	5.4%
Hydro	65	877	8	316	156	411	49	58	1,663	5.4%
Miscellaneous[(c)]	0	0	0	0	31	656	33	240	896	2.9%
Totals[(d)]	76	996	89	5,748	238	12,655	140	11,540	30,940	100.0%
Percent of Total MW		3.2%		18.6%		41.2%		37.6%		

Notes:
[(a)]Units in this table represent generator assets that may be power plants or individual units that make up power plants.
[(b)]Dual-fuel capacity is based on units with gas as the primary fuel; 11.5% of the units have oil as the primary fuel and gas as alternative fuel.
[(c)]Miscellaneous units include those fueled by wood, refuse, wind, and other renewable sources.
[(d)]Totals include settlement-only units.

Figure 2 [27]

Electric Generating Output (MWH) by Fuel Type – New England

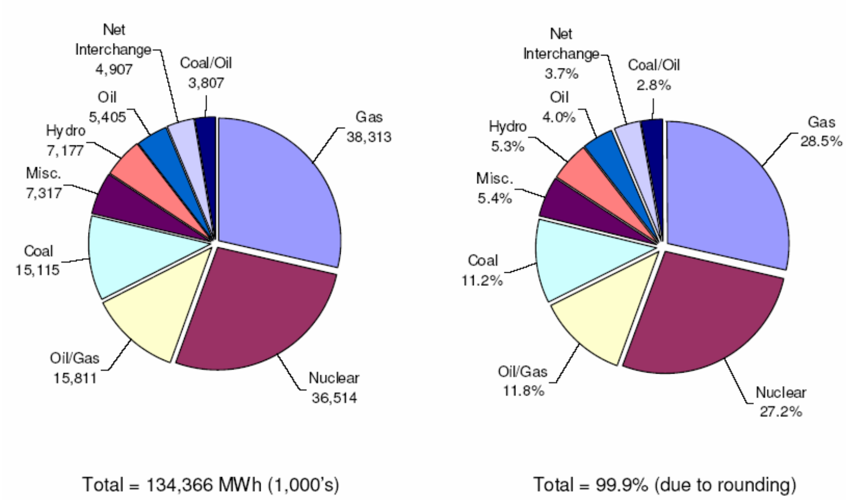

Figure 1.5 New England annual source of energy for 2004 (1,000 MWh and percent).
Note: Units in the "Miscellaneous" category include those fueled by biomass, refuse, and wind.

[26] Excerpted from RSP O5, Table 1.1.
[27] Excerpted from Draft RSP 05, Figure 5.1.

Table 7 [28]

Subarea Capacity Mix by Generation Type (Winter MW)

Subarea	BHE	ME	SME	NH	BOSTON	SEMA	CMA/ NEMA	WMA	RI	CT	SWCT	NOR	VT
Gas	540	270	542	1	1,863	1,276	0	247	1,786	0	788	0	0
Dual fuel	184	156	0	1,316	421	160	27	922	2,357	97	714	0	0
Oil	20	0	872	504	1,291	1,301	30	719	509	2,012	184	422	129
Nuclear	0	0	0	1,161	0	685	0	0	0	2,037	0	0	529
Coal	0	75	0	580	312	109	0	146	1,135	182	370	0	0
Pumped storage	0	0	0	0	0	0	0	1,665	0	0	29	0	0
Hydro	120	401	66	503	15	0	24	282	3	46	79	0	248
Miscellaneous	75	103	82	123	102	91	41	7	23	135	7	59	77
Total	**939**	**1,004**	**1,562**	**4,187**	**4,005**	**3,623**	**122**	**3,988**	**5,813**	**4,509**	**2,171**	**481**	**983**

While a result of a market-driven investment pattern tied to then-existing low gas prices and low air emissions, the region's addition of nearly 10,000 MW of gas-fired generation since 1999 has nonetheless diminished the fuel diversity of the region's energy supply. Total annual generation from natural gas has increased to 30 percent in New England, up from 15 percent just five years ago. More importantly, in 2004, units capable of burning gas (including dual-fuel units)set the price of electricity in the region's wholesale market 85 percent of the time; gas-only units set the price over half of the time. The ISO expects that continued commercialization of additional gas-fired capacity, and the potential retirement of non-gas facilities could increase this dependence over time.[29] Not surprisingly, wholesale spot market prices of electricity in New England closely track short-term variations in the price of its dominant marginal fuel – natural gas.

- *Aging Fleet of Generators.* Another result of the pattern of investment in electric generation over the past few decades is that the fleet of generators vary by age, technology and fuel type. Table 6 not only shows that the newest plants are predominately gas-fired, but also that many older plants are coal-fired (from the 1950s and 1960s) and nuclear (from the 1970s and 1980s). Typically, these coal-fired and nuclear generating stations are baseload units with fuels whose prices are not tied to changes in global fuel markets for oil and gas. Some of these older plants may retire, either because the older technology's efficiency and environmental profiles create high financial hurdles for continued operations, or because (in the case of the nuclear reactors) their 40-year operating licenses from the Nuclear Regulatory Commission must be renewed for them to remain in operation. If these plants retire for economic or other reasons, then New England will face even higher hurdles in meeting future infrastructure needs. Furthermore, while there are mixed attitudes among different segments of the public about these plants remaining in service for the long term, various public studies of the electric market (including RSP 05 and those prepared as part of the Northeast Regional Greenhouse Gas Initiative (described further below)) assume that the nuclear plants remain in operation, despite the cost and regulatory hurdles the plants face to receive license renewals and extensions.

[28] Excerpted from Draft RSP 05, Table 5.2.
[29] ISO New England, *Power Generation and Fuel Diversity in New England: Ensuring Power System Reliability,* August, 2005.

- *Transmission System Needs* – ISO also reviews in the Draft RSP 05 the current status and expected needs of the region's transmission system. ISO concludes that additional transmission infrastructure is needed to meet planning criteria in New England, and identifies 272 specific projects, most of which are reliability upgrades for ensuring that the region continues to satisfy reliability standards in an economical manner. Most of the estimated $3 billion cost of these upgrades are for six major 345kV projects that are mostly already underway. The ISO notes that many of the proposed transmission system projects will help improve power market efficiency by eliminating barriers to the flow of existing and new generation sources to load throughout the region.[30]

Our Assessment of the Region's Electric Infrastructure Needs

The Draft RSP and other ISO analyses reveal that the region's electric system – overall, and in particular sub regions – will become increasingly stressed over the next several years from reliability, fuel diversity, and economic perspectives. Specifically, current resources will be insufficient to maintain the reliability of the electric grid in parts of New England as soon as 2008. By next year they could be insufficient to meet Northeast Power Coordinating Council reliability criteria during high-load hours without resorting to OP 4 actions. From a cost perspective, there is an immediate need for quick-start generation in certain sub regions to lessen or eliminate the commitment of uneconomic generation, and thereby reduce the total costs to customers in those regions and states. There is uncertainty about the long-term status of certain stable fuel electric resources in the region (such as new wind projects, existing coal plants, existing nuclear plants, and future penetration rates of end-use energy efficiency actions and demand response). Finally, our heavy dependence on natural gas for capacity at times of winter peak, and for our annual energy requirements, represents an increasing reliability and economic burden on the region.

NATURAL GAS

New England finds itself in a unique situation with respect to natural gas – all it has is pipes and tanks. That is, New England has no supplies of natural gas of its own, and has effectively zero natural gas underground storage potential. This means that every cubic foot of gas burned in the region must first travel via pipe or tanker to get here. Review of the prospects for future supply, then, must begin with a look at pipeline and LNG storage capacity within the region, and expectations of production from supply sources outside the region.

Gas demand in the New England market has grown substantially in recent years, and is projected to continue to grow. For example, the all-time peak day gas sendout for local gas distribution companies in New England occurred in January 2004, and was 12 percent higher than the previous all-time peak (in January 2000).[31]

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[30] Draft RSP 05, page ES-10.

[31] Data from the Northeast Gas Association. (See, the presentation of Steve Leahy from the NGA: Regional Natural Gas Supply & Deliverability, Presentation to NECA's 11th Annual Energy Conference & Exposition, May 18, 2004.) NECA is the Northeast Energy and Commerce Association.

Recent Studies of New England's Natural Gas Market

The growth in gas use in New England, expectations for traditional continental supply sources for the region, and a growing supply/demand balance dilemma for New England have been the topic of several recent national and regional studies.[32]

Together, these studies present a relatively consistent picture of New England's gas supply and demand prospects:

- Production and/or export capabilities from the U.S. Gulf, Western Canadian, and Eastern Canadian sources – the North American supply basins that New England has historically relied upon to meet its natural gas demand – are diminishing or less than originally expected;

- There is growing nation-wide competition for these diminishing continental natural gas supplies, in part due to the significant growth in gas-fired electric generating capacity in many regions of the country in recent years;

- The effect of these supply/demand fundamentals has been rising gas prices and a more volatile supply price curve for natural gas;

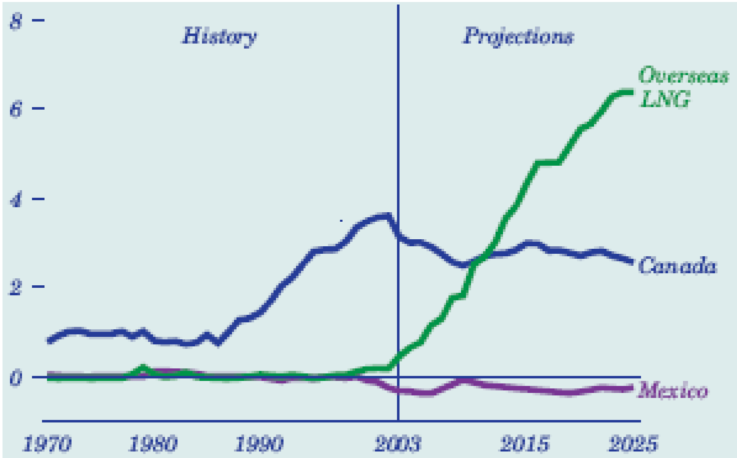
- There is expected to be continued high "peak-period" consumption of gas in New England relative to the off-peak periods, challenging the economics of adding new gas delivery infrastructure into the region because of potential periods of lower utilization during certain seasons;

- The interstate pipeline system between the North American gas supply basins and New England, which is at the tail end of most major delivery pipelines, is constrained at certain times of year, requiring that the region rely on in-region gas storage and interruptible gas markets to assure adequate supplies to firm-gas consumers during peak periods when pipeline delivery capacity is constrained;

- LNG imports from supply sources outside of North American gas basins are expected to become a dominant supply source for the country in the coming years (see Figure 3 below).

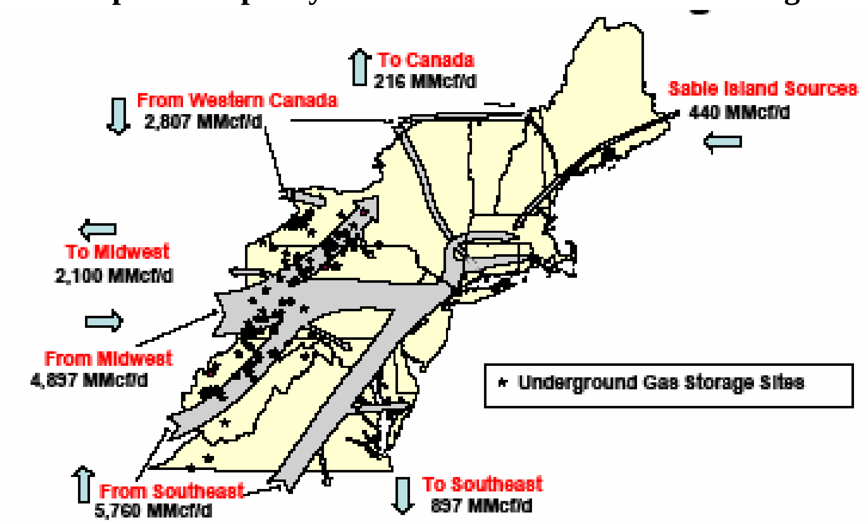
[32] Sources reviewed include EIA's *Annual Energy Outlook 2005* from February 2005 and *Global Liquefied Natural Gas Market: Status & Outlook* from December 2003, the Northeast Gas Association's *2005 Market Update* from May 2005, FERC's *Northeast Natural Gas Infrastructure* from December 2003, the Conservation Law Foundation's *Statements on LNG Siting* from May and June 2004, ISO-NE's *Final Report on Electricity Supply Conditions in New England During the January 14-16, 2004 'Cold Snap'* from October 2004, and the Governor's Task Force on Electric Reliability and Outage Preparedness' *Status of the Electric Grid in Massachusetts* from March 2004. These and other studies were previously reviewed in detail in: Susan Tierney and Paul Hibbard, *The Benefits of New LNG Infrastructure in Massachusetts and New England: The Northeast Gateway Project,* June 2005. See also the ISO-NE's recent 2005/2006 Winter Assessment.

Figure 3[33]
U.S. Net Imports of Natural Gas by Source



- If additional LNG terminals are located in or near New England, additional LNG can provide supplies to the region that do not need to enter the regional market by way of the highly congested gas pipeline system from the Gulf Coast. (see Figure 4 below.)

Figure 4 [34]
Gas Pipeline Capacity Into and Out of the Northeast Region



Note: MMcf/d = million cubic feet per day.
Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Pipeline Capacity Database.

Recent studies and reports focused on New England's natural gas markets thus confirm that new sources of gas are needed, especially ones that can be introduced into the region in safe,

[33] Excerpted from EIA, Annual Energy Outlook 2005, Figure 85.
[34] Excerpted from EIA, "U.S. Natural Gas Pipeline and Underground Storage Expansions in 2003," September 2004, page 9.

affordable and environmentally acceptable ways. Also, these studies indicate that unless new gas supply delivery infrastructure is added into New England in the very near future, the region will likely have difficulties meeting future peak day gas demand with sufficient reliability and at competitive prices.

The region will need to take steps in the near term to assure that there are adequate supplies for the future. This relatively urgent need for action has implications for users in traditional gas markets as well as in the electric market, for the private investors who need to act today to be ready to meet those consumers' needs, and for the government policy makers who will need to approve applications related to those actions. It also has implications for the amount of incremental gas supplies and the variety, type and amount of new gas delivery facilities that are needed to bring gas into the region.

The March 2005 NEGC Report

The most recent all-sector assessment of natural gas in New England was conducted for the New England Governors' Conference ("NEGC") in March, 2005 ("NEGC Report").[35] Prepared at the request of the Governors of the six New England states, this report of the NEGC's Power Planning Committee[36] assessed natural gas demand and supply options for the region. Overall, the report concludes that the region needs new supplies of natural gas and new delivery infrastructure to bring gas supplies to the region.

The report estimates the region's future demand for gas and describes the supply options available to the region. Additionally, it projects the timing of need for additional supplies, while also identifying the key assumptions and factors that affect the timing and character of new gas supply and delivery requirements.[37] For example:

- The report highlights the seasonality of New England's gas supply and deliverability challenges, which occur during wintertime months when space-heating requirements coincide with demand from gas-fired electric generation.[38]

- Based on staff estimates of the demand for gas along with an assumption that current LNG storage and vaporization capacity will remain fully available and usable for the foreseeable future, the report views the region as having adequate delivery infrastructure to meet winter peak gas demands through the next five years (to 2010). The report cautions that if current LNG storage and vaporization were unavailable during winter months, reliability problems would be felt immediately.

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[35] NEGC (Report of the Power Planning Committee), *Meeting New England's Future Natural Gas Demands: Nine Scenarios and Their Impacts*, March 1, 2005 (hereafter "NEGC Report").

[36] The Power Planning Committee is composed of directors of the New England States' energy offices and the commissioners of the region's public utility commissions.

[37] The NEGC Report was previously reviewed in detail in Susan F. Tierney and Paul J. Hibbard, *The Benefits of New LNG Infrastructure in Massachusetts and New England: The Northeast Gateway Project*, June 2005 (hereafter "Algonquin Report"). This section contains a synopsis of the NEGC Report and the subsequent evaluation in the Algonquin Report.

[38] While winter peak is the most important time for gas supply considerations, large increases in the quantity of gas used during the summer for electricity generation in New England and – more importantly – neighboring "upstream" regions, in combination with increased summertime pipeline maintenance could affect summertime gas pricing and unit availability (Draft RSP 05, pages 66 – 70).

- Given the time it takes to develop the substantial demand reduction efforts and/or to permit and construct the infrastructure that the report estimates will be needed to ensure reliable delivery of natural gas in the winters beyond 2010, the report finds that "state policies to encourage and develop these initiatives need to be implemented in the very near future."[39]

- After analyzing the economic, environmental, fuel-diversity, and reliability impacts to the New England economy as a whole which might be associated with nine alternative resource-development and demand-reduction scenarios,[40] the report makes observations about the relative merits of different approaches. The report views additional fuel switching at power plants, the implementation of energy efficiency, and the reliance on renewable energy sources as the least expensive ways to improve gas supply reliability while improving fuel diversity.

- The report recognizes expansion of any LNG delivery and storage terminals – on-shore and off-shore, in-region and out-of-region – as capable of providing considerably greater improvements to gas supply reliability when compared to fuel switching, electric energy efficiency, and renewable generation, as well as coal gasification and nuclear generation.[41]

- From a fuel diversity point of view, the report views energy efficiency and fuel-switching as the best approach for the region, with all of the LNG scenarios contributing substantially to improving the region's fuel supply diversity to some degree because they can provide fuel from a different part of the world than the source of most of our current pipeline gas supplies.

- From a public safety point of view, the report sees energy efficiency, renewables and coal gasification scenarios as posing the least security concerns. While it concludes that the security risks of LNG facilities near densely populated areas are higher, the risks of an uncontrolled release from an LNG facility are low (with consequences similar to "those that would occur if a tanker full of gasoline were similarly breached and ignited");[42] nonetheless, the report recognizes that while the technical estimates of such risks are low, the public concerns over them are high and must be addressed directly when regulators evaluate the relative merits of alternative LNG delivery and storage scenarios.

[39] NEGC Report, page vii.

[40] These nine scenarios include: (1) expansion of fuel switching at gas-fired power plants; (2) expansion of energy efficiency programs, such as implementing upgraded building energy codes, adopting more stringent appliance and product efficiency standards, and using additional energy efficiency measure to offset load growth; (3) renewable electric generation to represent 7%, 7%, and 6.5%, of retail sales in Massachusetts, Connecticut and Rhode Island, respectively, by 2012; (4) on-shore, in-region LNG expansion, to increase the volumes of vapor injected into the pipeline system and maintain or increase the volumes of liquid transported by trucks to other storage facilities within the region; (5) construction of new on-shore, in-region LNG facilities, to receive liquid and either vaporize it for injection into the pipeline system or transport the it using trucks to existing storage facilities around the region; (6) construction of off-shore, in-region LNG terminals, whereby a specially-equipped LNG tanker would dock off-shore and deliver vapor through a pipeline to the mainline infrastructure system; (7) on-shore, out-of-region LNG facilities to receive and vaporize liquid for injection into the pipeline system and move the gas into the New England region; (8) construction of coal-gasification facilities; and (9) construction of a new nuclear power plant. (See Id., pages 33 and 34.)

[41] Id., page ix.

[42] Id., page 54.

Finally, the report notes that the investment options analyzed (e.g., LNG infrastructure development, energy efficiency actions, renewable resource development, fuel switching at privately-owned power plants) arise from different combinations of government policy and private sector actions, so that the options are not purely equivalent in terms of their probability of occurrence. The report notes that development of energy efficiency programs depend heavily on government initiative (e.g., policies affecting program funding and delivery), so while they have shorter lead times and involve less-capital-intensive projects, they may still be difficult to realize depending upon government action.[43]

Our Assessment of Gas Needs

One of the principal and consistent themes of the many recent government, academic, and industry studies is that new gas supplies and/or delivery capability need to be developed starting in the immediate future in order to meet the New England's energy requirements. This is true even if the need for gas doesn't arise until 2010, as suggested by NEGC. But it is even more pressing given that we may need additional gas supplies and infrastructure well before 2010.

To better understand the timing issue, we carefully reviewed the NEGC analysis. Our assessment, presented in a report filed with the US Coast Guard in September of this year, reviews the sensitivity of the NEGC forecast results to modest adjustments in the key forecast drivers. In particular, adjusting the NEGC forecast for what we believe are more reasonable assumptions concerning variables related to LDC demand and gas-fired electricity generator availability and operation, the year of need advances by several years to as soon as 2007 (or 2009 if the contribution from energy efficiency and renewable resources is as assumed in the NEGC Report). (See Figure 5.) We think that these other assumptions are as – if not more – reasonable to use as the basis for planning for the region's critical energy needs. In addition, we note that the NEGC report presumes ideal interstate and intrastate natural gas supply and delivery system conditions, providing little margin for error in the reliability of existing infrastructure.

When we adjust the NEGC's forecast to reflect what we consider to be a more consistent and reasonable set of assumptions for reliability-driven resource planning, the result is more consistent with those of other observers and more in line with our own point of view on basic natural gas supply/demand fundamentals in the region. Specifically, the result indicates a relatively urgent need for additional gas supply and infrastructure – by as early 2007.

In any event, this supports the bottom line in the NEGC Report: that the New England region should act now to adopt policies to reduce demand *and* to develop further natural gas infrastructure so that additional natural gas supplies may be available in New England when needed.

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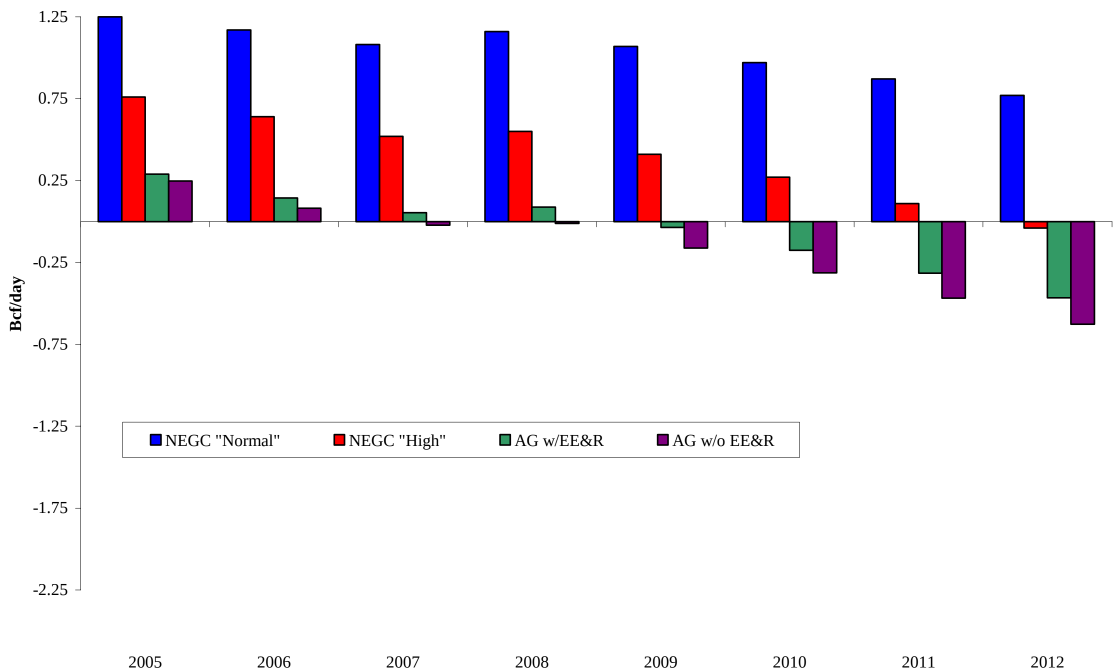
[43] Id.

Figure 5[44]

NEGC and Analysis Group ("AG") Forecasts of the Need for Natural Gas in New England on a Winter Peak Day With Vaporization

2005-2012 Bcf/Day



Note: EE&R refers to the reduction in gas demand assumed in the NEGC Report associated with energy efficiency and renewables.

SUMMARY

To be certain, today's forecasts of the future are imperfect. The models used by the ISO-NE, energy companies, government agencies and market participants all require simplified representations of the gas and electric energy systems, subjective decisions about key model inputs, and uncertainty associated with the assumed trajectory of future fuel pricing, weather, underlying economic growth, and changes in system infrastructure. None of them will predict the future accurately. Reliable planning exercises recognize this fact, capture those uncertainties and variabilities as much as possible, and set planning standards with an adequate margin of safety to allow for adequate supply or at least adequate response time in the face of inaccurate modeling or unexpected trends and events.

That said, all permutations of forecasts reviewed in this report – as well as non-modeling analyses of market fundamentals that we reviewed – suggest that there is already an urgent need for additional policy responses and/or investments and developments of electric and gas infrastructure now, so that this region can avoid resource adequacy problems that will be acute *by 2010 at the latest*. Review of sub-regional electricity needs, and other analyses of natural gas

44 Excerpted from Algonquin Gas Report, Figure A-2.

supply and demand factors, suggest that the dates of need could come much sooner – making it all the more important that appropriate policy and investment responses occur immediately.

Even assuming a need date for additional electricity and gas resources by 2010, five years is not a lot of time in the world of energy policy and infrastructure development. This is barely enough time for the process of deliberation, adjudication, and implementation of state policies to support additional conservation, demand management, and renewable resource development – particularly those aggressive enough to result in private sector responses with sufficient market penetration so that they can meaningfully contribute to reducing demand or increasing supply in the timeframe under consideration. Development of major infrastructure projects is also a multi-year, lengthy process – a process made all the more difficult when, as now, there is significant uncertainty in federal, regional or state rules governing market transactions, investment cost recovery and permitting processes. Indeed, projects that are not yet well advanced in the licensing process are unlikely to be available before 2009/2010, taking into account not only permitting, financing and construction but also the legal challenges that are becoming increasingly common place for energy facility development project.

There are many reasons for the New England region to plan carefully in advance for addressing coming needs, not the least of which is preservation of public policy in infrastructure planning. In California, when electric supply deficiencies reared their ugly head in the 2000/2001 energy crisis, the growing tensions between an electric industry moving to a competitive market structure and the traditional expectations of a credible and democratic facility siting process reached the breaking point. In the face of rolling blackouts, the state promptly executed emergency measures drastically curtailing siting reviews with the goal of building as many generating plants as quickly as possible.[45] Of course, frantic revision of state law and policy that potentially compromise the credibility of siting review, in order to get generating capacity in the ground in the face of rolling blackouts, is not and should not be the goal of any state or region. But the experience in California – while hopefully unique – serves as a stark reminder of the value of forward-looking and timely policy action, workable market structures, and credible resource planning processes. The forecasts of New England's needs for meeting electricity and natural gas demand over the next five years supports the active engagement now in market and policy deliberation of all government agencies and stakeholders involved.

Based on our review of supply and demand factors in the electric and gas industries, we believe the time is now for aggressively addressing electric and gas infrastructure needs. In the next section, we review three of the key policy contexts that will influence the development of infrastructure in New England in the coming years – the recent passage of the national Energy Act, containing numerous incentives for infrastructure development; the need for and likelihood of regional and/or national program to cap carbon emissions; and the status of electricity market rule development in the region. While we do not suggest that these are the only major influences, they do represent key policy decisions to be made in the near term, and that will have a major impact on energy infrastructure development over the next five years.

[45] Tierney, Susan F. and Paul J. Hibbard, *Siting Power Plants: Recent Experience in California and Best Practices in Other States*, Report for the Energy Foundation, February, 2002, pages 24-25.

NEW ENGLAND INFRASTRUCTURE SITING: POLICY CONSIDERATIONS

OVERVIEW

Gas and electric system reliability will be met over time largely through private investment by merchant companies and public utilities in demand- and supply-side infrastructure. What investments will be made will in turn flow from the incentives and constraints resulting from public policies, market structures, and the fundamental economic and operational characteristics of competing infrastructure resource and fuel options. Table 8 contains an overview of the key incentives and constraints associated with various energy options available to New England.

Examples of *public policies* that can influence infrastructure needs and development over time include: public utility commission ("PUC") requirements for gas and electric utilities in demand-side management programs; PUC policies that offer to consumers the option to take electric or gas service according to rates which vary hour-to-hour based on changes in the hourly rates over the seasons of the year; state PUC requirements setting forth the contracting period for companies obligated to offer "provider of last resort services" to basic-service electric customers; state renewable portfolio standards and renewable funding mechanisms; environmental requirements, such as those establishing the maximum number of days during which a gas-fired power plant may be permitted to operate on oil, or establishing a mandatory cap on carbon emissions from the power sector; national financial incentives for the development of clean coal and nuclear technologies; or state or federal siting process requirements.

Examples of *market structures* include regional demand response programs administered by the ISO-NE and integrated into the day-ahead and RT bidding and dispatch system; the structure of energy, reserve and ancillary services markets; market monitoring and mitigation rules; the form and function of capacity markets; markets for (and allocation of) emission allowances under cap and trade programs; the overall effectiveness of these markets in providing the opportunity to collect rates consistent with competitive market conditions (e.g., sufficient to allow entry of new investment into the market); and the ability of market participants to access inputs to production (including access to fuel, site permits, transmission).

Economic and operational characteristics of different resource are affected by these public policy and market structure mechanisms, but are heavily dependent on plant-specific fuel prices and price projections, operating and maintenance costs, capital costs and plant configuration, size, etc.

There are, of course, many emerging economic, market, and policy factors that will ultimately govern the development of energy infrastructure in New England over the next five to ten years. In the sections that follow, we review three that will be key factors – without claiming that they will be the only or even necessarily the most important ones. First, we summarize those provisions of the new federal energy legislation that appear to be most important from the standpoint of infrastructure development. Next, we summarize the current form of the policy proposal put forth by New England and other Northeast states for capping emissions of carbon from electricity generators. Finally, we discuss the current status of efforts related to administration of a longer-term market for installed capacity in New England.

Table 8
Energy Infrastructure Incentives and Constraints in New England

Infrastructure Option	Key Incentives	Key Constraints
Energy Conservation Actions	• Energy prices • PUC requirements &/or public benefit charges	• Cost/benefit analysis • Multiple retail market impediments • Uncertain institutional responsibility in retail access environment • Uncertain investment recovery in retail access environment
Demand Response	• Energy prices • Cost savings on peak	• Retail pricing policies; • Limited technical eligibility/application; • Cost of necessary metering technology
Renewable Capacity (examples vary by type of renewable)	• Renewable portfolio standards • "Public Benefit" Renewables funds • Federal, state tax incentives • Stable "fuel" costs • DOE "critical resource" designation	• Capital costs • Capacity value • Interconnection issues • Loss of QF put under Energy legislation • Instability of federal/state policies • Potential siting challenges
Gas/Oil Capacity	• Relatively low capital costs (CT and CC units) • Operating characteristics (e.g., relatively favorable heat rates) • Emissions (relatively low for larger CC gas units)	• Uncertain investment recovery rules • Fuel costs and fuel availability • Fuel diversity issues • Emissions limitations for burning oil • Siting issues of oil storage, and access to gas and power transmission lines, near load centers
Coal Capacity	• Stable Fuel Costs • Fuel diversity issues • Incentives in Energy Policy Act for advanced coal technology	• High capital costs • Investment recovery rules • Emissions (particularly Carbon) • Other environmental considerations (e.g., waste) • Siting challenges – including coastal sites with access to deep water ports
Nuclear Capacity	• Stable Fuel Costs • Relatively low capital cost for license extensions • Incentives in Energy Policy Act for permitting advanced nuclear	• Siting challenges • High capital costs for advanced nuclear • Uncertain investment recovery rules • Management of radioactive wastes
Transmission	• Energy Policy Act provisions: FERC backstop siting authority, investment recovery and tax incentives, DOE "critical" corridor designation	• Siting challenges • Investment recovery treatment
Gas Pipelines	• FERC authority	• Adverse economics of firm delivery agreements (given that current cost-recovery for typical gas-fired power plants do not support long-term firm gas transportation contracts needed to support new gas delivery capacity)
LNG	• Relatively favorable economics compared to many North American gas sources • FERC jurisdiction clarified in Energy Policy Act	• Siting challenges (onshore and offshore) • Economics of firm delivery agreements (given that cost-recovery for typical gas-fired power plants do not support their long-term firm gas supply agreements, and that sellers sell in highest-value international gas markets (which may not be New England)).

NATIONAL ENERGY POLICY ACT

In August 2005 President Bush signed into law the Energy Policy Act of 2005 ("Act"). As widely touted throughout the debates leading up to and following its enactment, the Act contains numerous direct financial and regulatory incentives for the development of additional energy infrastructure in all energy sectors of the economy. There are many provisions – like repeal of the Public Utilities Holding Company Act ("PUHCA") – that are likely to indirectly affect infrastructure development through changes in industry structure as well, since they create incentives for consolidation of ownership of electric companies, access to capital and consolidation of systems over the long-term. In this summary we focus on the more near-term and most directly relevant components of the legislation from the standpoint of electric and gas infrastructure development and investment

In many respects, the Act is an economic stimulus package for energy infrastructure development. There are provisions making reliability standards in the electric industry mandatory; providing regulatory, tax and other financial support for new nuclear and "clean coal" development projects; offering new tax provisions for electric transmission and gas delivery infrastructure; assuring clearer jurisdiction to site LNG facilities and gas pipeline projects; providing tax incentives and royalty relief for oil and gas exploration and drilling infrastructure; establishing incentives for natural gas storage; providing tax and R&D support for emerging advanced coal, nuclear and renewable resources; and enhancing the regulatory and siting authority of the FERC with respect to energy infrastructure projects.

Specifically, infrastructure-related provisions include the following:

- The Act makes compliance with electric system reliability standards mandatory, and enforceable, where they have been voluntary in the past. The standards may be adopted and administered by the new FERC-approved national Electric Reliability Organization, with required adherence by users, owners and operators of bulk power systems. The Act also increases FERC's enforcement/penalty authorities under the FPA.

- The Act requires that DOE identify "national interest transmission corridors," and provides FERC limited backstop siting authority for the construction of new transmission facilities. While ultimate authority appears to still reside with state action, the new authority for FERC under the Act provides significant leverage for requiring that states act on transmission siting requests, particularly where DOE has identified such projects will eliminate constraints and benefit consumers.

- The Act requires that FERC issue rules to provide for incentive-based recovery of transmission investment costs that may include returns on equity strong enough to attract investment, with the goal of increasing reliability and reducing costs associated with transmission congestion. This is in addition to the revised federal tax treatment for transmission investment, allowing for a shorter depreciation period for transmission property (from 20 to 15 years).

- The Act clarifies and expands FERC jurisdiction over the siting, construction, expansion and operation of onshore LNG facilities, gives FERC the authority to establish deadlines for state permitting processes, and codifies FERC policy providing LNG owners more flexibility in establishing commercial arrangements for LNG sales.

- The Act establishes certainty with regard to the legal venue for and expedited review of certain state and federal agency permitting actions.

- The Act allows companies to charge market-based rates for new natural gas storage capacity, and provides economic measures (including royalty relief, and inventories of resources in the Outer Continental Shelf) to support increased activity related to drilling for natural gas and oil, and/or for identifying potential drilling sites.

- The Act includes extensive R&D provisions in virtually all fuels for electric generation. It also authorizes loan guarantees for "innovative technologies" with the potential to avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases. Eligible project categories include: (1) renewable energy systems, (2) advanced fossil fuel technology (including coal gasification), (3) hydrogen fuel cells, (4) advanced nuclear facilities, (5) carbon capture and sequestration practices and technologies, including terrestrial sequestration, (6) efficient electrical generation, transmission, and distribution technologies, (7) efficient end use technologies, (8) production facilities for fuel efficient vehicles, (9) pollution control equipment, and (10) gasoline refineries.

- The Act reauthorizes and expands the Price-Anderson Act for commercial nuclear plants, authorizes the construction of a new nuclear reactor at Idaho Falls, creates a federal loan guarantee program for advanced technologies including nuclear, and provides additional R&D funding for certain nuclear-related advanced technologies. Additionally, the Act provides for risk insurance to underwrite costs incurred as a result of permitting delays for the first six advanced design nuclear plants built by the industry.

Many of these provisions supporting infrastructure development in the Act will affect regions other than New England. For example, while support for emerging coal generating technologies and new nuclear plants and even new oil refineries may spur the siting of new facilities in some parts of the U.S., there are many factors – geographical, social, economic, political and others associated with the structure of the electric industry in the region – which make it unlikely that New England will be the first or even an early candidate for the development of high-capital-cost, advanced nuclear and coal generation projects. However, many of the Act's provisions enhance the economics (and thus prospects) for siting LNG, electric transmission, and renewable generation capacity, and increase the regulatory authority to enforce a level of reliability for bulk power systems. Similarly, tax credit provisions related to more efficient homes and appliances could serve as a boost for energy efficiency measure adopted within the region.

CLIMATE CHANGE

There is an emerging consensus in the scientific community that global warming is occurring, that the warming is changing the Earth's climate, that increasing concentrations of greenhouse gases, primarily CO_2, are to blame, and that most of the warming in recent decades can be attributed to human activities.[46] Increasingly, too, there is pressure on the U.S. to adopt some form of national mandatory controls on greenhouse gas emissions. Many energy-company

[46] Joint Science Academies Statement: Global Response to Climate Change, signed by the heads of the national science academies of Brazil, Canada, China, France, Germany, India, Italy, Japan, Russia, UK, and USA, June 2005.

executives are calling for greater certainty in the nation's climate policy, so that they can better plan for climate-related impacts on energy prices and investment decisions.[47] State treasurers in many states (including Connecticut, Massachusetts, and Vermont) are calling for companies to disclose their business risks related to climate change – both the impacts of global warming and the policies related to it.[48] The bi-partisan National Commission on Energy Policy recommended last December that the nation adopt a mandatory economy-wide, cap-and-trade program on greenhouse gas emissions.[49]

Of particular note in the Senate version of the bill leading up to Congress's adoption of the Energy Policy Act, the Senate concluded that greenhouse gases are accumulating in the atmosphere, causing temperatures to rise at a rate outside the range of natural variability, that there is a growing scientific consensus that humans are to blame, and that a mandatory program will be required to stop or slow the growth in greenhouse gas emissions. The Senate version thus included a "Sense of the Senate" that Congress should enact a comprehensive and effective national program of "…mandatory, market-based limits and incentives on emissions of greenhouse gases that slow, stop, and reverse the growth of such emissions at a rate and in a manner that (1) will not significantly harm the United States economy; and (2) will encourage comparable action by other nations that are major trading partners and key contributors to global emissions."

No mandatory greenhouse gas emission control program was included in the final Act. The provision nonetheless signaled a shift in the politics of climate change in Washington, one that is being followed up on as Senate Energy and Natural Resources Chairman Pete Domenici (R-NM) is currently holding full committee hearings on climate change, with the intention of offering legislation to impose mandatory controls on emissions of greenhouse gases.[50]

For New England's part, as part of the Northeast states' Regional Greenhouse Gas Initiative, or "RGGI," the six New England states have been cooperating over the past two years to attempt to design a regional cap-and-trade program for control of (initially) CO_2 emissions from power plants within the region. A combination of staff working group deliberations and stakeholder meetings has been held to consider program design options, model the economic and environmental impacts on states of such a program, and ultimately to develop a program that could be agreed upon and enacted through state regulation. All New England states are participants in the RGGI process.

On August 24, 2005, the RGGI Staff Working Group issued a revised proposal for a program to control CO_2 emissions from power plants in the region. Specifically, the proposal includes the following elements:[51]

- A cap and trade program would start in 2009, with an initial review of program design and effectiveness in 2015;

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[47] For example, Jim Rogers, CEO of Cinergy, and Paul Anderson, CEO of Duke. (see, e.g., *Testimony of James E. Rogers Before the House Science Committee*, June 8, 2005, and Paul Anderson, *Taking Responsibility*, speech to the Charlotte Business Journal's 10th Annual Power Breakfast, April 7, 2005)

[48] Institutional Investors Summit on Climate Risk, New York City, May 10, 2005, www.ceres.org .

[49] National Commission on Energy Policy, Breaking the Stalemate: A Bipartisan Strategy to Meet America's Energy Challenges," December 2004.

[50] Environment and Energy Daily, *Senate Panel to Tackle Economics of Greenhouse Gas Cuts*, September 19, 2005.

[51] Memorandum from RGGI Staff Working Group to RGGI Agency Heads re: Revised Staff Working Group Package Proposal, August 24, 2005 (www.RGGI.org, accessed September 22, 2005).

- Emissions would be "stabilized" at approximately 150 million tons through 2015, followed by a 10% reduction between 2015 and 2020;
- The regional cap would be apportioned among the 9 RGGI states (including in addition to the New England states, Delaware, New Jersey, and New York) based roughly on historic emissions;
- Allocation of allowances within states would be left to each state, though all states agree to set aside approximately 20 percent for public benefit purposes, and 5 percent for a fund to achieve additional carbon reductions, in a way that will address potential emission leakage issues arising from electricity pricing effects at the boundaries of the RGGI region; and
- Offsets would be allowed for specific technologies and measures.

At this writing, the RGGI program has not yet been finalized, let alone implemented. But the prospects for some kind of controls over the greenhouse gas emissions from combustion of fossil fuels seems within the foreseeable horizon. Further, even the RGGI Staff Working Group proposal assumes that the region will need new energy infrastructure to comply with the program. For example, modeling in support of the proposal assumes not only that the licenses of the region's nuclear units are extended, but also that several thousand megawatts of new gas-fired generating capacity are installed to help meet the greenhouse gas reduction targets. For these assumption to be met, of course, many of the issues we discuss in this report must be addressed.

Given the continuing uncertainty over the timing and form of climate policies, however, its effects complicate the outlook for energy infrastructure investment. Energy infrastructure has a long life, as do the human health, safety, and environmental risks – like those related to climate change[52] – that come with it. That fact, along with the growing scientific and political consensus concerning atmospheric trends, and the need to take action to address climate change, suggests that carbon emissions be factored into any realistic long-term energy policy or energy infrastructure development strategy. This may be particularly important for New England given the existing contribution to baseload energy production from non-carbon sources that face retirement or relicensing decisions over the coming ten to fifteen years – namely hydroelectric and nuclear generation.[53] The sooner that carbon policy is resolved – or at least that there is a more certain policy than exists today – the clearer will be the rules affecting energy infrastructure development.

From a strict investment risk perspective, the likelihood of a regional and/or national carbon control regime coming into effect over the lifetime of energy infrastructure investments, and the potential financial impact on project profitability, requires an assessment of carbon control risks as part of that investment strategy. This seems particularly likely in New England. This risk supports the idea that the region should refocus efforts to obtain additional mechanisms or policies to reduce demand and support the growth of non-emitting generation. We cannot

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[52] The risk of climate change is qualitatively different than those associated with other air pollutants, in that climate change involves potentially extreme, global consequences, while the timing, magnitude and location of the impacts remains uncertain and controversial; the impacts for the most part are likely to be realized geographically and temporally distant from the source; and it involves a high degree of irreversibility – once emitted, CO_2 remains in the atmosphere, contributing to warming, for a very long time.

[53] For example, EPRI recently released modeling analysis equivalent to that used in the RGGI process, but assuming retirement of approximately one-third of the nuclear capacity within the RGGI region. Analysis results revealed increases in the construction of new gas-fired capacity and electricity imports, increases in RGGI region CO2 emissions, and increases in program costs, relative to the RGGI modeling results. EPRI, *Letter to Karl S. Michael, NYSERDA, Regarding Electric Power Research Institute (EPRI) Sponsored Modeling Results*, September 9, 2005.

imagine how the region will meet its greenhouse-gas emissions reduction goals without investment in diverse, low-carbon-emitting, new energy infrastructure.

NEW ENGLAND CAPACITY MARKET

For the past several years, the region has been debating the merits of alternative approaches to assuring adequate investment in electric generating resources. Ever since the adoption of a restructured electric industry nearly a decade ago in New England, the region has been struggling with designing and instituting an appropriate set of market rules and obligations to create efficient incentives for investment and adequate system reliability.

This journey is still underway. The earliest approaches adopted by NEPOOL and implemented by the ISO didn't work; and neither did the second and third attempts. FERC has instructed that the current approach is unsatisfactory, and in 2003 ordered ISO-NE to find a means to appropriately compensate generators for the reliability value they provide and to do so in a way that does not distort price signals in energy markets, as FERC says is now the case. In response, ISO-NE developed and proposed the "Locational Installed Capacity" (or "LICAP") approach to resource adequacy. The ISO's proposal would compensate all resources in New England for their role in maintaining local reliability – and would pay resources more when power supplies are tight and much less when there is excess supply available. Under this model, an administratively-determined "demand curve" would establish the market clearing price for capacity in future years – with prices expected to be higher in certain locations when resources are needed, relative to prices in other regions. After weighing opposing positions of a multitude of parties (including state regulators and other public officials in the New England states) involved in the FERC proceeding in which the ISO's LICAP proposal is being reviewed, the FERC's Administrative Law Judge assigned to the case recommended approval of the basic contours of ISO-NE's LICAP model in June 2005.

Recently, state regulators from many New England states, along with other parties, have been developing an alternative approach, the "New England Resource Adequacy Market" ("NERAM") with an auction-based approach designed to provide compensation to generators who add incremental capacity to the region in the future. And Congress stated in the Energy Policy Act (adopted at the end of July 2005) its "Sense of Congress" that FERC carefully consider the views of the states in considering the ISO's proposed LICAP mechanism.

Perhaps not coincidentally, the FERC issued an order in early August delaying implementation of the LICAP approach until no earlier than October 2006, and allowing further argument on the issue. At the FERC hearing on the matter in mid-September, the FERC chairman expressed his concerns that New England was facing a situation that "bears an uncomfortable resemblance" to the power supply problems California faced in the late 1990's.[54]

As the debate stretches on, one of the clear consequences is that no new investment in capacity resources is forthcoming[55] until there is greater certainty in the cost recovery rules governing capacity investment. Without this issue being resolved, it isn't reasonable to expect energy companies to make any of the kinds of decisions that are necessary to address long-term firm fuel

[54] Tina Seeley, "LICAP Alternatives Must Do More For New England Power Supply – Kelliher," *Energy Daily*, Thursday, September 22, 2005.
[55] Beyond the one project – Cape Wind – which is still in development and permitting.

supply commitments, or fuel-switching investments, or new power generation projects. It is too risky – politically risky – for them to do so.

Without a resolution of this issue, we are in a situation where we say that we don't want to tolerate fuel price volatility and unreliable supplies of electricity and gas, but today's prices in the power market do not reflect this preference. Consumers may be enjoying the reliability and economic benefits of past capacity investments, but they cannot expect to see future ones without paying prices that reflect giving investors a reasonable opportunity for a market return on their investment.

For the time being, no one inside the region or in Washington knows what form that New England capacity market will take in the future. The continuing uncertainty surrounding this central issue in the region's power market design is untenable, and clouds the record of success of the region's electric industry restructuring efforts. The region should settle this issue with all due haste; the region's economic and environmental and energy security interests depend on it.

POLICY SUMMARY

These three critical policy considerations interact strongly with each other. Additional energy infrastructure development will be helped by certain federal policy opportunities. The recently-passed federal legislation provides regulatory and financial incentives for the development of critical power generation, electric transmission and natural gas infrastructure, as well as institution of a requirement that the bulk power system be operated to meet reliability standards. These provisions should aid in the development of infrastructure in the coming years.

These provisions are probably not sufficient to stimulate the kind of substantial investment in energy infrastructure that the region needs. Just as – if not more important – are the steps that the region must take to resolve the market rules that will govern long-term financial incentives for the development of new electric generating capacity. Given the long lead times for project development, permitting and construction, combined with the relatively short time frame in which we can expect to have comfortable energy reserve margins, this issue cannot wait any longer to be resolved.

Finally, we can no longer ignore the risks of climate change associated with increasing emissions of carbon dioxide and other greenhouse gases, or the risks of future carbon controls. The sooner the region clarifies its policies on emissions of carbon dioxide from the electric sector, the sooner that prospective developers can take them into account when considering options for energy infrastructure development in the future.

SUMMARY

The foregoing description of supply and demand considerations in New England's electric system forms the basis for our conclusions and recommendations. Our Executive Summary describes our views about the actions and policies needed to move our region forward to a future of secure and environmentally-appropriate energy policy and infrastructure. We need not to repeat these observations here, except to make the following summary:

1. The need to begin development of new energy resources in New England is upon us.
2. Uncertainties affecting energy markets are chilling investment.
3. Energy efficiency should be an important component of any resource mix, and is all the more likely and cost-effective, given today's high energy prices.
4. Incremental gas supply and delivery capability is essential.
5. New electric transmission investment will help reliability and competitive wholesale markets.
6. The region needs to support actual renewable projects, not just pro-renewables policies.
7. New England's energy costs are comparatively high.
8. There are no silver bullets for meeting New England's near-term energy needs; all options should remain on the table.