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Research Report

The Challenge of Energy Policy in New England

by Carrie Conaway

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Executive summary

The Challenge of Energy Policy in New England

New England needs a reliable supply of energy for its day-to-day functioning and its economic growth. The right mix of fuels and technologies must be in the right place at the right time, all the time. Because of the long lead times in building energy infrastructure, ensuring system reliability requires making decisions, investments, and policy today that will allow the region to meet expected demand many years from now, while at the same time buffering the region from the impact of unexpected short-term changes in energy markets. And this, in turn, requires both well-functioning markets and carefully crafted public policies.

Reliability is of particular concern to New England, for several reasons. First, the region is lacking in traditional indigenous sources of energy. This means the region's energy sources come at higher cost because they must be transported farther to get here, and it can also leave the region vulnerable to interruptions in supply and price spikes in world markets. Second, some are concerned that the deregulated structure of the region's wholesale and retail electricity markets may not be providing the right incentives for firms to invest in new generation capacity, which could threaten system reliability. Third, most agree that even if the right incentives were in place, it would still be difficult to find communities willing to host this new infrastructure because of the region's fragmented local decision making and increasing community concerns about the safety, security, and economic impacts of these facilities.

New England's state governments can and should take a more active role in ensuring system reliability. They can work to maintain the region's fuel diversity by responding to the region's dramatic growth in natural gas demand and by experimenting with incentives to promote renewable energy sources and new technologies. They can reduce demand through new energy pricing structures and energy efficiency programs. They can work with ISO New England and energy regulators to improve the incentives for investing in electrical generation. And they can smooth the process of siting new infrastructure so that community, regional, and national considerations are all given due weight.

New England's energy problems were not quickly created, and they will not be quickly resolved. But they cannot be ignored, for they are too important to the region's future. Without the assurance of an energy system that can meet immediate demands along with long-term growth, the region puts its economic prosperity at risk.

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– Carrie Conaway

The Challenge of Energy Policy in New England

Energy has once again moved to the forefront of the nation's attention. High and volatile oil and natural gas prices—some of which have increased as much as 200 percent over their most recent lows in 1997–1998—have been attracting concern over the last several years. The East Coast blackout in August 2003 created estimated economic losses of $4.5 billion to $10 billion—0.1 percent of U.S. gross domestic product—even though the blackout lasted just one to three days and affected less than 20 percent of the U.S. population.[1] And then there was Hurricane Katrina. In the initial days of the August 2005 storm, approximately one-third of domestic oil production, one-fifth of domestic natural gas production, and nearly one-tenth percent of the nation's refinery capabilities were taken offline; an estimated 4.5 million customers in Louisiana and Mississippi lost electrical power. Half a year later, most of the refinery capacity had recovered, but some refineries were operating below their normal capacity; oil and gas production had still not returned to previous levels.

All these problems point to why energy policy matters: for our day-to-day functioning and our economic growth, we need a reliable supply of energy. But creating a reliable energy system takes more than just having enough capacity and variety of sources to handle routine disruptions without incident. We must also plan ahead to ensure that the right infrastructure—whether natural gas pipelines, electrical power plants, transmission and distribution wires, or fuel oil and gasoline delivery systems—is available in the right place and at the right time. Because of the long lead times in building energy infrastructure, this requires making decisions, investments, and policy today that will allow the region to meet expected demand many years from now, all the while buffering the region from the impact of unexpected short-term changes in energy markets.

Reliability is of particular concern to New England, for several reasons. First, the region is almost completely lacking in indigenous conventional sources of energy—no coal deposits, no oil fields, no sources of natural gas. This means the region's energy sources come at higher cost because they must be transported farther to get here, and this can also leave the region vulnerable to interruptions in supply and price spikes in world markets. Maintaining a diverse mix of fuels is one way to hedge against these problems, and indeed, employing diverse fuel sources has historically been one of New England's assets. However, recent regional trends in natural gas demand have changed this picture. The region's fast pace of growth in gas use, coupled with recent gas price spikes and their attendant impact on consumers, has raised questions about whether the region has overinvested in natural gas to the point that it has put system reliability at risk.

New England's energy reliability hinges on creating the right balance between market incentives and public policy.

System reliability has also been affected by electricity deregulation, which has substantially changed the region's wholesale and retail electricity markets over the last decade. Investment in new capacity has declined in recent years, leaving some analysts concerned that the new market may not be providing the right incentives for firms to undertake this investment. And most agree that even if the right incentives were in place, it would still be difficult to find communities willing to host this new infrastructure because of fragmented local decision making and increasing community concerns about the safety, security, and economic impacts of these facilities.

While markets play a key role in attaining energy reliability, they are unlikely to provide a complete solution, because reliability is in many respects a public good. First, the fact that one person "consumes" reliability does not use up all the reliability. It remains available to everyone in the market, at least up to the point where the system becomes overloaded. Second, once a reliable energy system is established, it is difficult to prevent customers from enjoying it even if they did not pay for that level of reliability. Thus even though energy producers may appreciate the social benefits of reliability, each has an incentive to let someone else pay for it. Under these circumstances, private firms will tend to underinvest in reliability relative to what would be desirable from a social point of view. Only through government intervention will firms take the extra steps needed to create a reliable system, because only government can use the tools of regulation and taxation to ensure the optimal level of reliability.

Ensuring New England's future energy reliability, then, will require not just well-functioning markets, but also carefully crafted public policies. Indeed, governments need to take action to address several areas of immediate concern for New England's energy reliability. The first is maintaining the region's fuel diversity, which contributes to reliability by acting as a hedge against price spikes and interruptions in supply. Government could promote fuel diversity by reducing the growth in the region's demand for natural gas, encouraging renewables, and promoting alternative sources of electricity. Second, strategies to reduce or shift demand, such as encouraging energy efficiency and introducing real-time pricing, serve to reduce the region's capacity needs, which in turn fosters reliability by easing pressure on the existing infrastructure. Third, improving the incentives for infrastructure investment and siting enhances reliability by ensuring that sufficient infrastructure is planned and built and that it is sited fairly, so that capacity growth meets expected demand growth over the longer term. Public policy can play a role here by ensuring that appropriate incentives for investment are in place and that community, regional, and national needs are all taken into consideration whenever infrastructure siting decisions are made. Determining the appropriate degree of public intervention in energy markets will not be easy, but it is critical for a reliable energy future for New England.

New England's energy: yesterday, today, and tomorrow

Throughout the years, New England's quest for a reliable energy system has been shaped by both market forces—such as available resources, technology, and relative prices—and public policy. In the pre-colonial and colonial eras, technology and available resources dictated that the energy source of choice was wood. In *Changes in the Land: Indians, Colonists, and the Ecology of New England*, William Cronon writes, "A typical New England household probably consumed as much as 30 or 40 cords of firewood per year.... Obtaining such a woodpile meant cutting more than an acre of forest each year. In 1800, the region burned perhaps 18 times more wood for fuel than it cut for lumber."[2]

As industrialization took off in the 1800s, the demand for new energy sources grew in response to the new needs of industry and individuals alike. New England's abundant supply of water, which could run the waterwheels and coal-fired steam turbines used in many industrial applications, helped fuel the region's industrialization. In the early twentieth century, electricity generated from hydroelectric dams and steam generators replaced water as the primary energy source for industrial applications. By 1920, coal- and oil-fueled steam generators accounted for more than two-thirds of all electrical generating capacity in the region, and over 90 percent in Connecticut, Massachusetts, and Rhode Island.[3]

Also around the turn of the century, policymakers began to involve themselves more in energy markets, initially to ensure equal access to electricity. The generation, transmission, and distribution of electricity were viewed as a single economic unit and as a natural monopoly: a capital-intensive industry with large economies of scale and scope. Because monopolies can restrict production and increase prices above competitive levels, most state governments believed that they could enhance economic efficiency by regulating the industry. They granted each utility control over a certain geographic area and set rates to protect both the public interest and the return on investment to the utility. By 1916, 33 states had established energy regulatory agencies; and in 1920, the U.S. Congress created the Federal Power Commission (the predecessor to today's Federal Energy Regulatory Commission).[4] Another key role of policy at this time was expanding electrical access both through the establishment of federally funded public power plants, such as the Hoover Dam and the Tennessee Valley Authority, and through the Rural Electrification Act of 1936, which provided loans and assistance to companies that expanded electrical access in rural areas.[5]

A combination of market and policy forces also influenced the trajectory of natural gas usage in the region. Price controls and other regulatory policies enacted in the late 1930s had the effect of discouraging investment in natural gas nationwide. These policies, along with technical and material constraints, meant that the natural gas pipeline did not reach the region until the 1950s. Even in the 1960s and 1970s, natural gas made up less than 10 percent of the region's total energy use. Recognizing the problems that previous policy had created, the National Energy Act of 1978 took steps to create a single national natural gas market and to gradually allow the market, rather than regulators, to determine the wholesale price of natural gas. However, the Act restricted the use of natural gas for new electrical generation and industrial purposes. The natural gas industry and its necessary infrastructure were not adequately developed at that point, and supplies appeared to be insufficient to satisfy demand for both home heating and electrical generation purposes. It wasn't until these restrictions were lifted and other related policies changed that gas demand grew substantially in New England.

Looking to the future, demand in all energy sectors is expected to continue to grow. With respect to electricity, ISO New England (the independent group that monitors the region's wholesale electricity markets) estimates that New England's electricity demand will increase from 132 gigawatt-hours per year in 2004 to 153 gigawatt-hours in 2014, a 16-percent increase over the decade and an annual growth rate of 1.5 percent.[6] The North American Electric Reliability Council also forecasts a 1.5 percent annual growth rate for the coming decade, predicting a 14.5-percent increase in peak electricity demand over the nine years between 2005 and 2014.[7] Including energy for all uses and from all sources, the Energy Information Administration predicts a 1.2 percent annual increase in New England's overall energy demand over the next 20 years, from 3.6 quadrillion Btus today to 4.5 quadrillion in 2025. Per-capita energy demand growth will be slower, at 0.6 percent annually over the period. New England governments and energy providers will need to plan ahead to meet this increased demand while maintaining system reliability.

Competitive markets play a key role in attaining reliability, but they are not a complete solution.

Maintaining a diverse fuel mix

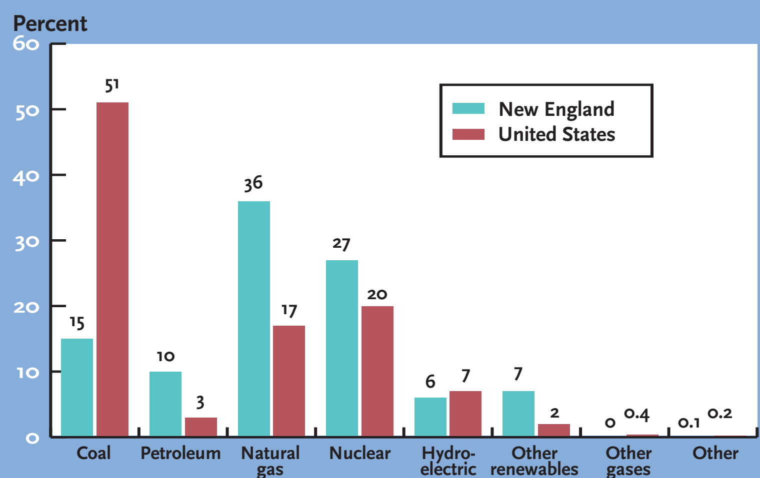
One way for the region to sustain reliability is to maintain its diverse fuel mix. Fuel diversity has historically been a hallmark of New England's energy system, serving as a hedge against the impact of unpredicted changes in markets and interruptions due to infrastructure breakdowns. This hedge has been particularly important for New England because of its limited indige-

Electricity: From Turbines to Traffic Lights

by Antoniya Owens

Electricity is one of the most prevalent forms of energy. We use it to heat and light our homes and offices; to power our refrigerators, computers, and manufacturing equipment; and to coordinate our air traffic and factory production. Electricity is also a key input into the digital infrastructure of our knowledge-based economy. While most people think of electricity purely as a source of energy, it is in fact derived from other energy sources, such as fossil fuels, nuclear fission, moving water, and renewables. Indeed, electrical power plants consumed nearly 40 percent of total primary energy in the United States in 2004. Because electrical generation is such a large energy user, understanding the relationship between electricity production and consumption is critical for understanding how the energy system works as a whole.

Electricity Generation by Fuel Source
As a share of total electricity generation, 2003



Source: Energy Information Administration.

Most electric power stations in the United States use generators with steam turbines to produce electricity. Steam is forced with massive pressure against blades mounted on the turbine's shaft, causing the turbine to rotate and spin the generator. The majority of steam turbines in the United States are powered by fossil fuels: coal, petroleum, or natural gas. Typically, the fuels are used to heat water and produce the steam that moves the turbine blades. Other plants burn natural gas and petroleum to produce hot combustion gases that directly move the blades of the gas turbine, or to fuel engines that power the generators through the mechanical energy of internal combustion. In 2003, 70 percent of the nation's electricity, and 61 percent of New England's, was created from coal, petroleum, or natural gas.

In nuclear power stations, by contrast, the steam that spins the turbine is produced from water heated through nuclear fission: the process of splitting atoms of uranium or other

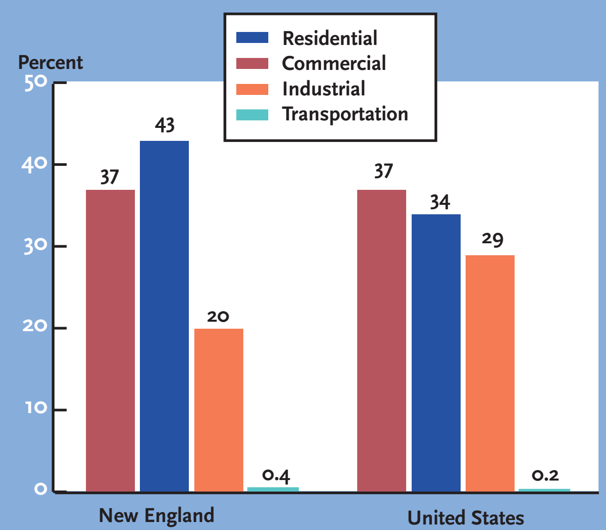
nous conventional energy supplies. But the relative importance of fuel diversity is changing. Today's national and global energy markets have meant that all regions now buy much of their energy on the open market and thus are at risk when prices spike. As a result, nonproducing areas like New England are less vulnerable to fluctuations, while producing areas are more susceptible. However, the amount of energy that needs to be transported into New England, and the region's location at the end of most energy supply chains, still means that maintaining diversity of fuels and of suppliers is an important piece of sustaining the region's energy reliability.

New England as a whole enjoys a relatively diverse energy portfolio, by most measures the most diverse in the nation. (See charts on pages 10 and 11.) Compared with the other major U.S. Census regions, the region is less dependent on coal and ranks in the middle of the pack with respect to natural gas usage. It also makes greater use of nuclear power and of renewable sources, such as wood and water, than other regions. The region's sources for electrical power generation are particularly diverse, with no one source accounting for more than about one-third of total generation. Nuclear power is more commonly used in New England than elsewhere as a result of investments in nuclear power plants in the 1960s, 1970s, and 1980s intended to reduce the region's dependence on imported fuels. Petroleum also plays an unusually large role in electrical power for the region, accounting for 10 percent of generation here versus 3 percent nationwide. One reason is that nearly one-quarter of New England's generradioactive elements into their component parts, a byproduct of which is heat. In 2003, almost 20 percent of all electricity in the United States and 27 percent in New England was generated at nuclear power stations.

In hydroelectric power units, generators can be powered by falling water, which is accumulated in dam reservoirs and released to apply pressure against the blades of the turbine; or by the run of the river, in which the river current itself moves the blades. In 2003, 7 percent of all U.S. electricity, and 6 percent of New England's, was generated through hydropower. Renewable fuels such as solar, wind, geothermal, and biomass account for a relatively small share of electrical generation nationwide, at 2 percent, while the share is somewhat greater in New England, at 7 percent.

Regardless of how electricity is produced, it is a vital source of energy across the economy. Residences accounted for more than one-third of total U.S. electrical consumption in 2003. The commercial sector—usually service providers such as hospitals, post offices, or grocery stores—accounted for another third. And electrical consumption by industrial users, such as manufacturing, construction, agriculture, and mining, made up an additional 29 percent. Its share has decreased from nearly 50 percent in 1960, largely due to the decline of manufacturing's share of the economy. Industrial consumption is even lower in New England, at under 20 percent in 2003; energy-intensive industries have shied away from locating in the region because of its relatively high energy costs. In only one sector, transportation, is the role of electricity almost negligible. Here, petroleum is by far the dominant energy source; nationwide, the transportation sector consumed just 0.2 percent of all electricity in 2003.

Electricity Consumption by End-Use Sector
As a share of total electricity consumption, 2003



Source: Energy Information Administration.

ating capacity comes from dual-fired power plants—ones that can be easily switched between two alternative fuel sources, typically natural gas and fuel oil, in response to changing relative fuel prices.

The current level of fuel diversity has been less a result of an active effort to diversify by the public or private sector than of the long-lived nature of infrastructure investments. The technology an energy company chooses to employ at any given point in time results from the interplay of a variety of factors, such as the expected relative prices of fuels, the relative efficiency and capital costs of different technologies, and the regulatory environment. For example, an electrical generating company might choose to build an oil-fired power plant if oil prices are expected to remain low, if the plant can operate efficiently, and if clean air regulations are not restrictive. That oil-fired plant will last a very long time. As prices, technology, or the regulatory environment change over the life of the power plant, another source of energy—say, natural gas—might come to look more attractive than oil. In the past, this process has yielded diversity, since the old oil-fired plants were still in service even as new natural gas plants were added to the mix.

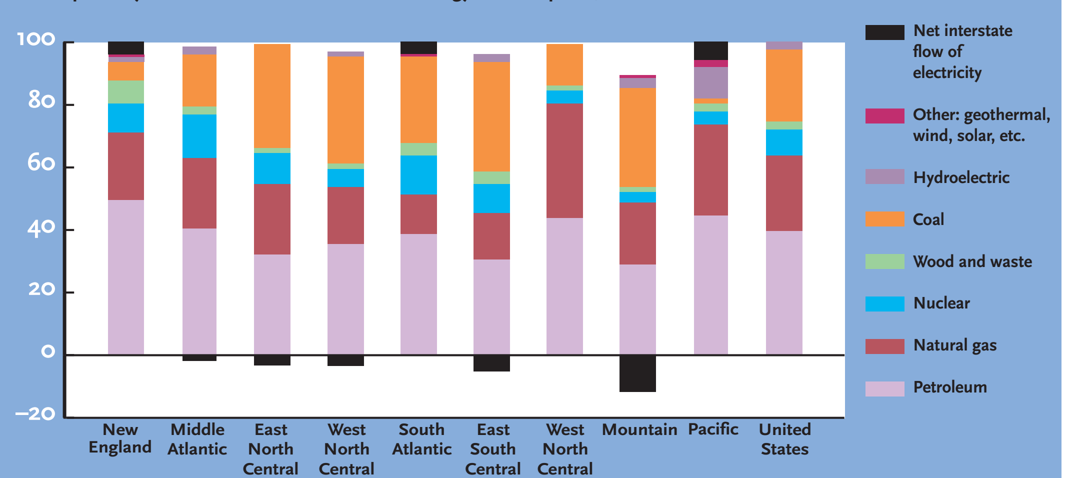
Although diversity has historically occurred without much government intervention, this is not guaranteed to continue in the future. And while we do not know precisely what the optimal fuel mix or level of diversity is, we know that becoming less diverse is undesirable for a region that must import so much of its fuel and that buys so much on the open market. Thus, taking policy action to maintain the region's fuel diversity—such as policies designed to moderate the growth in natural gas demand, encourage renewables, or promote new technology—can help the region exert more influence over its energy outcomes.

Meeting the challenges of growth in natural gas demand

Of all the issues related to fuel diversity in New England, the one that has attracted the most attention and concern is the region's recent sharp increase in natural gas usage. The region has no natural gas of its own; and for many years, the small capacity of the pipelines serving the region limited New England's use of natural gas. Indeed, the region still had the lowest natural gas demand per capita in the nation even into the 1990s. But today, more than 20 percent of the region's total energy demand, and over one-third of its electricity generation, comes from natural gas. Roughly 80 percent of this gas is supplied via the pipeline from the Gulf Coast and Canada, and the other 20 percent is delivered through the liquefied natural gas (LNG) terminal in Everett, Massachusetts, built in 1971. Virtually all of the region's power plants built in the last decade are fueled with natural gas. And Energy Information Administration projections show that natural gas is expected to continue to increase as a share of the region's overall energy use through the year 2025, raising concerns that the region's existing capacity may not be sufficient, particularly at times of peak demand.[8] How did we change so much, so quickly?

Fuel Diversity

Consumption by fuel source as a share of total energy consumption, 2001



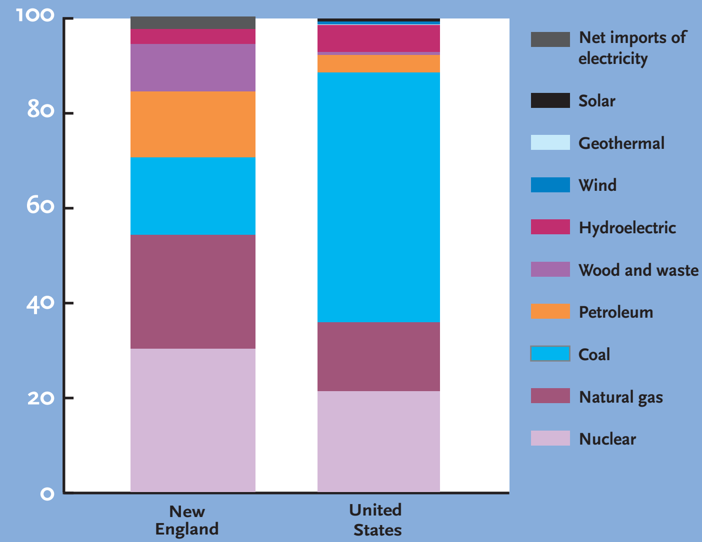
Source: Energy Information Administration.

First, several restrictions on natural gas use stemming from the 1978 Energy Policy Act were repealed in the late 1980s, allowing more use of natural gas for electrical generation.[9] In addition, concerns about the impact of fossil fuel use on air quality increased the appeal of natural gas across the country. Natural gas is far cleaner burning than coal, oil, or gasoline, emitting much smaller amounts of nitrogen oxides, sulfur dioxide, carbon monoxide, particulate matter, and reactive hydrocarbons. Another attraction is that gas is now known to be in relatively abundant supply globally, and to date the United States has been able to meet most of its natural gas needs from within its borders or from its friendly neighbors, Canada and Mexico. Thus, its supply is perceived as less geopolitically risky than petroleum, for which production and reserves are disproportionately concentrated in the Middle East. And there were financial incentives as well. The price of natural gas was declining going into the early 1990s after a peak in the early 1980s, making it relatively more attractive from a financial point of view.

Beyond these national trends, the electricity generation sector in New England faced especially large incentives to switch to natural gas. Nuclear and coal power are actually the least expensive sources of electricity when considering only the marginal cost of producing electricity from an additional unit of fuel. But nuclear plants have extremely high capital costs, problems with disposing of their spent fuel rods have yet to be resolved, and their construction has historically attracted intense opposition because of safety concerns. As a result, no new nuclear plants have come online in the United States since 1996.

Electric Power Sector Consumption

Consumption by fuel source as a share of total energy consumption by the electric power sector, 2001



Source: Energy Information Administration.

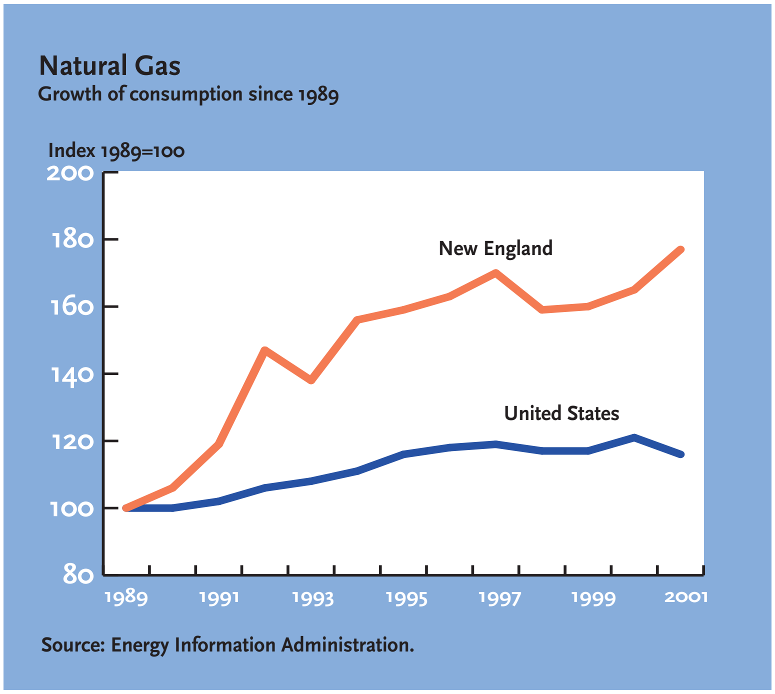
Likewise, coal is expensive to transport into the region and creates greenhouse gas emissions, a key concern in highly environmentally regulated New England. Natural gas-fired power plants have much lower capital costs per unit of capacity than coal- or nuclear-fired plants, and they are also more fuel-efficient, cleaner, smaller, and quicker to build. In addition, some can be built with the option to switch to fuel oil if oil prices dip below gas prices—an attractive feature in New England, which already has a well-developed fuel oil delivery system. Given New England's regulatory environment and tradition of local control over facility siting, natural gas generation facilities have proven the most attractive to communities and the easiest to actually get through the regulatory approval process.

The expansion of the natural gas pipeline and the incentives to increase natural gas usage have resulted in growth in natural gas demand in New England far outpacing that of the other Census regions in the last decade, whether measured overall or per capita. (See chart on page 12.) All types of customers—residential, commercial, industrial, transportation, and electrical generators—have dramatically increased their natural gas usage . The largest increase was in the electrical sector, which increased its natural gas use from about 90 trillion Btus per year in 1990 to nearly 280 trillion Btus today.

This rapid growth merely brought New England's gas usage in line with the rest of the nation's, and it has contributed to cleaner air and lower costs for consumers. But increased use of natural gas is not without its problems. The region is already viewed by some as overreliant on gas for its energy needs, leaving it more vulnerable to price spikes and reductions in supply. In fact, we are already starting to see evidence of this vulnerability. A cold snap during the winter of 1999–2000 caused temporary natural gas pipeline shutdowns, and spot-market gas prices (which are highly correlated with electricity prices) spiked briefly to levels 60 percent higher than the previous year. Another cold snap in 2004 produced an all-time winter peak in electrical demand. Power plants frequently hold natural gas contracts that provide a lower price in exchange for allowing their supply to be interrupted during peak demand conditions. As a result, some electrical generators went offline during the peak. Others decided to sell their natural gas for heating or industrial use at a high and relatively certain profit rather than make it into electricity and receive a potentially lower profit. While no electrical outages occurred, these cold snaps exposed key vulnerabilities in the current natural gas supply and power generation systems. News reports in fall 2005 expressed concern for the winter of 2005–2006, particularly in the event of extreme weather conditions. Fortunately, this past winter, weather was mild.[10]

Taking steps to promote fuel diversity through policy can help the region play a more active role in its energy future.

Whether it comes from the pipeline or from LNG, the region's supply of natural gas will need to be augmented to keep up with growing baseload and peak demand. ISO New England reports that there is adequate, but not ample, pipeline capacity for the next five years, although they are concerned about the potential short-term



impacts of cold winters. Over the next five years, some incremental new supply may come in the form of liquefied natural gas imports, but ongoing difficulties and delays in siting these facilities mean this supply is not guaranteed. Meanwhile, more and more demands are competing for the existing capacity, as other regions and countries also increase their use of natural gas. Under these circumstances, prices are likely to continue to rise, and capacity constraints may worsen.

Since the effect of natural gas dependence on reliability essentially stems from an imbalance of supply and demand, there are two options for resolving the issue—increasing supply or reducing demand. States that wish to increase supply could provide financial incentives to increase pipeline capacity, liquefied natural gas facilities, or natural gas storage capability, or they could change the oversight process to make it easier to site new infrastructure in their communities. States that wish to reduce demand could restrict how natural gas is used, promote natural gas conservation or efficiency, or find ways to increase its price to end consumers. A challenge for state governments, however, is that states are not the sole or even primary decision makers on many of these matters of policy. The Federal Energy Regulatory Commission, for example, regulates natural gas facility siting and the terms and conditions of its interstate trade. As a result, the solution to the region's growing natural gas dependence will likely require coordination and compromise among the states, the federal government, and the energy business community.

Encouraging renewable energy

Renewable energy plays a potentially significant role in fostering reliability through fuel diversity. Renewable energy sources, such as hydroelectric, solar, wind, wood, and municipal solid waste, are often praised solely for their environmental friendliness. But they also broaden options for supply, thereby providing balance to the conventional array of oil, coal, nuclear, and gas. In addition, they are typically indigenous to the region they serve and therefore are less vulnerable to the vagaries of import markets. Renewable energy sources currently make up about 9 percent of total energy use in New England; 13 percent of the region's energy use for electrical generation comes from renewables.

Every New England state except New Hampshire has a renewable portfolio standard—a requirement that a certain percentage of its electrical generation must come from renewable sources. Typically the percentage requirement starts low (around 1 or 1.5 percent) and becomes stricter over time. Maine is an exception, with a 30-percent renewables requirement for retail electrical generators. Though 30 percent may seem high, this standard is actually below the amount Maine's generators are currently producing, since many of them run on wood waste generated by the forest products industry.

Retail electricity deregulation has brought greater renewable options to consumers. (See sidebar on page 16.) Of the five New England states that have deregulated their retail markets, all except New Hampshire provide at least one "green" power generator option. Consumers that choose a green generator pay a fee—in the range of 1 to 3 cents per kilowatt-hour—in addition to the normal market rate for their electricity. That extra money supports generation from renewable sources, which is often more expensive than traditional-source electricity and therefore normally would be squeezed out of the market.

Consumers across the United States also have the option of purchasing renewable energy certificates, which offset less clean energy use in one location with cleaner energy generated elsewhere. However, these programs are little used; fewer than 100,000 consumers nationwide were enrolled in such a program in 2003.[11]

Beyond the federal incentives currently provided by the Energy Policy Act, most New England states offer incentives to promote the use of renewable energy. Often these take the form of tax credits or loans for businesses that purchase or convert vehicles to run on cleaner fuels or that install cleaner-fuel refueling facilities. Some also exempt cleaner motor vehicle fuels, or alternative-fueled vehicles themselves, from sales taxes. In addition, most New England states require that their state-owned fleet of vehicles meet certain fuel economy standards.

Renewable energy sources have disadvantages as well as advantages, however. Although their costs have decreased in recent years, many renewables are still more costly than traditional sources. Some are also available only intermittently; for example, wind can be variable and hydroelectric is seasonal. And while many people are in favor of renewables in principle, many are also unhappy when faced with the prospect of a windmill or a trash-burning power plant in their neighborhood. These facilities face the same siting and investment difficulties that any electrical facility would, as the developers of a proposed wind farm off the coast of Cape Cod have discovered in recent years.

Promoting new technology development and adoption

In the last few years, new energy technologies have emerged that may improve energy efficiency, air quality, or cost to consumers at the same time that they promote reliability by diversifying fuel sources. However, many have stumbled along the path leading to their adoption and widespread use. Government incentives for research, development, and dissemination of these products could pay off over the long run in cleaner, cheaper, and more efficient energy use as well as a more reliable energy system.

One example is integrated gasification combined cycle (IGCC) plants, which, when combined with carbon sequestration, can create electricity from coal with emissions as low as those of a natural gas plant. This technology is being used in several plants overseas, but adoption in the United States has been slow. One factor is the perception that the technology still needs to be tested on a large scale and in utility operating environments; another is lack of familiarity with how the technology works. These question marks have led investors to view it as a risky alternative. A third concern is the high capital cost and long payback period. Recent IGCC demonstration projects have yielded estimated or actual capital costs in the range of $1,500 per kilowatt of capacity, significantly more than the cost of a conventional coal facility.[12] Fourth, and most important for policymakers, the benefits of IGCC accrue largely to the public, rather than to investors; so private firms will be likely to invest less in this technology than would be socially optimal.[13]

Reducing demand for energy can help with fuel diversity simply by reducing the pressure to build new infrastructure.

IGCC may not be the best solution for New England. If natural gas or oil prices drop in the future, an IGCC project might end up being undercut by gas or oil—especially likely in New England since coal is so expensive to transport here. In addition, New England's geology does not allow for the carbon sequestration necessary for the maximum reduction in emissions. But the story of IGCC does demonstrate that there is potential for state governments to help encourage technologies like these as a way of promoting energy reliability without sacrificing air quality. Indeed, the federal government has already taken the first steps. The recently passed federal energy policy offers tax credits and loan guarantees to promote coal gasification projects.[14] State governments could follow suit with their own incentives for promoting particular technologies that would meet their needs.

Reducing demand

Government can also promote reliability by taking steps to reduce demand. Indeed, this approach can have the most immediate impact on reliability by taking pressure off the system by quickly taking pressure off the system at periods of peak demand. This, in turn, means that energy companies can serve the same customer load using less capacity. Public policies that attempt to reduce demand typically work either by changing the price signals consumers face or by improving energy efficiency.

Currently, most customers are insulated from fluctuations in wholesale electricity prices. Residential consumers typically pay the same amount for each unit of energy consumed, regardless of whether they are using those units of energy in the afternoon of the hottest day of the year or in the middle of the night during the fall. Commercial and industrial customers can participate in ISO programs that pay them for shifting their electrical load to nonpeak hours or reducing their load when overall demand is highest. But still, these prices and payments are generally negotiated ahead of time rather than reflecting the actual value of electricity at the time of usage. Policymakers could dampen demand by exposing electricity customers more directly to the wholesale price of electricity, perhaps by requiring that all customers have the option of paying rates that are calculated hourly in real time and ensuring that the necessary metering equipment is in place to accommodate this. More price exposure should theoretically create a reduction in demand in response to an increase in price. Demand response policies, as they are called, should help reduce the need to build additional capacity, since they decrease the peak demand on the system.

New England outranks the other Census regions in government spending on energy efficiency programs.

By promoting energy efficiency, on the other hand, policymakers attempt to reduce not just peak demand, but also the overall level of end-use consumption. Likely as a result of the high cost of energy in the region (and thus a stronger incentive to conserve), New England has been a national leader in energy efficiency. The American Council for an Energy-Efficient Economy reports that New England far outranks the other Census regions in government spending on energy efficiency programs, both per capita and as a percentage of total utility revenue. Four of the six New England states are in the top 10 on both measures, and all six are in the top 20.[15]

It appears that the region's investments in programs such as increasing appliance efficiency standards, upgrading building energy codes, and providing tax incentives for energy-efficient products and practices are paying off.[16] For example, the northeastern United States is the most efficient of the four major U.S. regions in terms of Btus of energy used per square foot of residential space, even after adjusting for unusual regional weather patterns.[17]

A May 2005 study by Northeast Energy Efficiency Partnerships highlights that the region could achieve even greater efficiency gains if state legislatures adopted more policies that supported efficiency—for example, by requiring that a certain percentage of demand growth be met by improving energy efficiency rather than by increasing capacity.

Infrastructure investment and siting

Beyond maintaining fuel diversity and reducing demand, another element of system reliability is ensuring sufficient investment in capacity to meet long-run needs. Without new infrastructure coming online to meet demand growth, excess capacity will be absorbed, facilities will become obsolete, and the system will run with fewer and fewer reserves—all of which will increase the chance of limitations on supply, increased prices, and, in the case of electricity, blackouts. To maintain reliability, the region needs policies that set appropriate incentives to promote sufficient investment in needed energy infrastructure—whether natural gas pipelines, electrical transmission wires, or electrical generating facilities. And it must locate this infrastructure in a way

Why are energy prices high in New England?

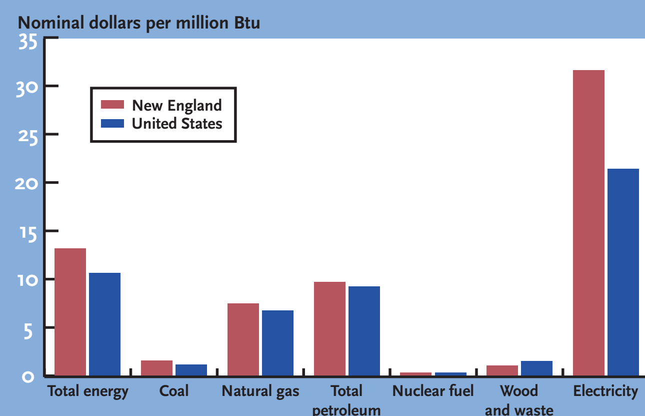
New England is known as a high-cost region relative to the rest of the country, and its energy prices are no exception. On a per-Btu basis, prices for most fuels are higher—sometimes nearly 50 percent higher—in New England than in the rest of the nation. On average, the region pays $13.31 per million Btus for its energy versus $10.72 for the United States as a whole. Price differences are particularly noticeable for coal (31 percent higher) and electricity (47 percent higher). The region did, however, pay less than average for nuclear fuel and for wood and waste.

The primary factor driving the region's high prices is transportation costs. New England must import nearly all of its fuel sources and thus must pay more for the same amount of energy than other regions to cover the additional costs of transportation. For example, because of coal's substantial weight, transportation costs are about 40 percent of the total delivered cost of coal, according to the Energy Information Administration's Coal Transportation Rate Database. Thus one would expect that coal prices in New England would likely be higher than elsewhere, since the coal would need to be transported farther to get here. Indeed, as noted above, final coal prices to New England consumers are about 30 percent higher than the U.S. average.

But other issues besides transportation costs may also come into play. The region may pay more for its electricity, for example, because it has chosen to strictly regulate emissions from coal-fired generating plants. This has led generators to switch to cleaner but more expensive sources of fuel, particularly natural gas. Differences in taxation policy across states may also make a difference. For instance, the New England states generally have higher gasoline taxes than the rest of the nation, with rates varying from 18 to 30 cents per gallon in December 2003 versus a U.S. weighted average of about 18 cents per gallon, according to the Energy Information Administration. This obviously increases the end price to consumers.

Higher prices do not necessarily translate one-for-one into higher expenditures, however, since consumers can control the impact of prices on their pocketbooks by reducing their demand. Taken together, New England's residences, businesses, transportation systems, and power plants consume less energy per capita than those in other regions—an average of 257 million Btus of energy per capita each year versus 338 million for the United States as a whole. In the end, the region's lower consumption makes up for its higher prices. New Englanders pay an average of $2,473 per capita for their energy needs, only slightly higher than the U.S. average of $2,433.

Average Fuel Prices
New England and the United States, 2001



Notes: New England prices are the price averages of the six states, weighted by consumption. The prices of the primary energy sources used for electricity generation reflect fuel costs per kilowatt-hour and are not adjusted for capital costs. Electricity is considered a secondary energy source.

Source: Energy Information Administration.

that not only meets expected demand growth and regional infrastructure needs, but also is perceived as fair and responsive to the concerns of local communities.

Incentives for investment

Building energy infrastructure is an expensive and risky proposition. Natural gas generators are the cheapest to build since they are relatively small; Energy Information Administration data show that the typical gas generator in New England has a capacity of less than 100 megawatts. Yet at $450 to $600 per kilowatt of capacity, even these small facilities can cost tens of millions of dollars to build. A new coal generator, at $1,200 to $1,400 per kilowatt and a typical New England capacity of 300 megawatts or less, would cost significantly more. Nuclear plants, the most expensive option, produce an average of 1,000 megawatts of capacity, but at a high cost: in the neighborhood of $2 billion apiece. Before businesses incur these costs, they need clear signals that their

Electricity deregulation: A recent history

Before the wave of electrical deregulation in the 1990s, a single utility company would receive a monopoly franchise to provide three electricity-related services to a given geographic area: generation (converting an energy source such as coal or natural gas into electricity); transmission (taking that electricity from the power plant across high-voltage power lines to a local electrical substation); and distribution (moving electricity at reduced voltage from the substation to the end consumer). Utilities were responsible for ensuring that the electrical system was reliable in both the short and long run, and for serving all customers in their geographic territory. Regulators were responsible for ensuring that utilities charged a fair price to consumers and that they received the opportunity for a fair rate of return on their investments.

The market for wholesale and retail electricity in New England changed dramatically in the 1990s.

By the mid 1990s, this system had proven increasingly unsatisfying. The gap had widened between the wholesale cost of generation and the final price charged to retail customers, leaving large industrial customers, in particular, aggravated that they could not negotiate directly with wholesale energy providers to take advantage of lower prices. The way the regulations were structured gave utilities an incentive to overbuild capacity, passing along those costs to consumers. And some customers were threatening to leave the utility-provided system and create their own generators. Pressure built on both the wholesale and retail markets to make some changes.

The groundwork for deregulating wholesale electricity markets had come as early as 1978 with the enactment of the Public Utilities Regulatory Policies Act, and more intensively when the Federal Power Commission (now the Federal Energy Regulatory Commission, or FERC) started to allow electrical generators that were not part of utilities to access utility transmission and distribution systems. But the big shift to wholesale deregulation came with the Energy Policy Act of 1992 and associated regulations issued by the Federal Energy Regulatory Commission. The new law and new rules gave FERC the authority to require utilities to allow other wholesale market participants to access transmission lines. Utilities also began to divest their generating capacity as part of restructuring deals in which customers received the right to choose their retail power supplier while utilities received the right to charge all customers for the utility's "stranded costs"—the costs remaining on investments made on behalf of customers who would now be able to depart; these costs could not be recovered in a com-

investments are likely to pay off—that they will have a fair opportunity to recover both the fixed cost of the initial investment and the variable costs of production with the revenues they will earn, and that the regulatory environment is not likely to change in a way that would substantially diminish their long-run profitability.

While setting appropriate investment incentives is critical across the energy infrastructure spectrum, it is the incentives for investment in electrical generation that have attracted the most attention and concern, particularly in the post-deregulation environment. (See sidebar above.) Before deregulation, utilities were responsible for serving the existing load and ensuring that there was enough excess capacity to meet customer demands and reliability requirements. But because profits were a function of the rate of return on capital investment, rather than expenditures made or efficient performance, utilities had an incentive to adopt more capital-intensive technology and to invest more than may have been socially optimal. This worked well enough so long as demand was growing, as any excess capacity would eventually be absorbed. But when the oil crisis and environmental concerns coincided in the 1970s, capacity growth continued despite slowing demand growth, perhaps because utilities and regulators did not initially realize that the demand slowdown would persist. Customers ended up bearing the costs of these excess investments in the form of rate increases. One guiding principle of the energy deregulation movement was that by making the market for electrical generation more competitive, investors rather than customers would bear the risk of their investment decisions, and, as a result, the costs to consumers would decrease.

In the first few years after New England deregulated its wholesale markets, it appeared that the new deregulatory environpetitive market. This left utilities (now called distribution companies) in charge of transmission and distribution and created a more competitive wholesale market for electricity generation. In regions that have deregulated their wholesale markets, the electrical grid is managed by regional bulk power coordinating organizations called Independent System Operators (ISOs).

The retail side of the market has always been regulated by the states, not the federal government. States' regulatory activity has focused primarily on setting retail rates for consumers, a process involving deciding which power plant investments and contracts were lowest-cost and thus allowed to be included in rates. About half the states have deregulated their retail markets, primarily by offering more choices of generators to consumers. In deregulated retail markets, consumers no longer must use the local monopoly electricity provider for their electrical generation but can select other generators depending on price, environmental concerns, and so forth. The idea is that this should spur price competition and eventually lower costs to consumers.

The impact of the changes has been hard to measure and generally smaller than anticipated.

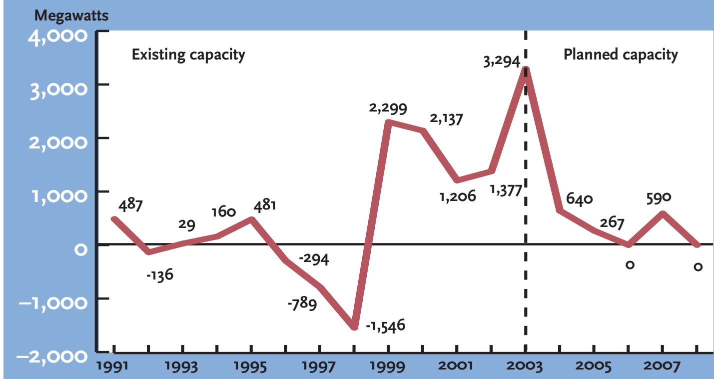
The impact of wholesale and retail deregulation has been hard to measure, but it has been generally smaller than expected. It is true that costs to consumers have frequently declined in deregulated areas, but a recent study by the Government Accountability Office questions whether this is attributable to deregulation itself or to other factors changing at the same time, such as decreasing input prices or customer price reductions put through by regulators. It is also not clear whether deregulation has yielded increased accessibility to new energy products, another desired outcome. In the end, the industrial firms that are the largest consumers of electricity have probably gained the most from deregulation; for them, seeking new electrical providers has created significant savings. For residential and small business consumers, the tradeoff is less clear. According to a report issued by the National Council on Electricity Policy in June 2003, the average residential customer would save only about $8 per month by switching providers.

In the future, deregulation is likely to continue to advance, although perhaps more slowly, on the wholesale side, since FERC is promoting its deregulated "standard market design" as a nationwide model. On the retail side, it appears that the momentum behind deregulation has stalled. No states have restructured their electrical markets since 2000, and at least nine of those that passed restructuring legislation have slowed or stopped its implementation.

ment was providing adequate incentives for investment. The region's overall electrical capacity had declined by 2,600 megawatts between 1995 and 1998, as investors grew nervous about how deregulation would unfold. But once the parameters of the policy became clearer, investors came back into the market, increasing capacity by more than 10,000 megawatts over the next five years. (See chart on page 18.) In recent years, however, new investment has slowed. According to the Energy Information Administration, as of 2003, about 1,500 megawatts of new capacity were scheduled to come online in New England by 2008; it is not known how much more capacity might come online after that or how much might be taken offline in the interim. This amount of investment may be sufficient for the region as a whole right now, since the capacity built in the late 1990s is still being absorbed.

But it will not be sufficient for long; current capacity problems in parts of the region assure the eventual need for more capacity. Electricity can be transported over significant distances, but transmission losses to electrical resistance mean that at some point it becomes more economical to transport more fuel to a region than to transport the electricity itself. In addition, transmission wires are physically limited and can carry only a certain amount of power, restricting the amount of electricity that can be imported from elsewhere. As a result, several large geographic areas within the region, notably southwestern Connecticut, eastern Massachusetts, and northwestern Vermont,[18] are currently load pockets—areas in which strong demand, limited generating capacity, and barriers to importing electricity from elsewhere threaten the reliability of local and regional electrical service. There is increasing concern around the region that without additional investment in capacity, these load pockets will no longer be isolated problems, but rather the bell-

Generation Capacity
Existing and planned nameplate capacity in New England, change from previous year



Source: Energy Information Administration.

wether of a broader regionwide shortfall in electrical capacity.

Businesses are reluctant to invest in needed generating capacity in New England because of the nature of the market for electricity. Ideally, the wholesale market should send signals to businesses to invest appropriately in new capacity. But even the best-designed electricity markets operate in a world with imperfections, such as the electrical industry's tendency toward natural monopoly, which can distort investment incentives. In addition, part of the region's capacity needs stem not from the immediate demands of customers, but from the need to maintain reserves in order to ensure system reliability. Thus private businesses are unlikely to invest enough to meet the region's full reliability needs, since they receive no return on excess capacity.

In order for energy markets to create the right incentives for investment, several conditions must be met. First, in the wholesale market, the market-clearing price of electricity must be allowed to vary sufficiently to reflect what is known as the "value of lost load," or VOLL. This measure values wholesale electricity in terms of how much it is worth to customers to avoid a power interruption. The value of lost load can vary considerably, depending on whether or not the outage was anticipated, what time of day it occurred, how long the power was out, weather conditions (electricity is worth more on very hot days), and so on. Outages are typically much more costly for industrial customers than they are for residential customers. If prices reflected the value of lost load in New England, the VOLL on a typical day when demand is moderate and supply is ample would likely be in the range of \$60 to \$80 per megawatt-hour.[19] But on days when demand for electricity is high and capacity is limited, the VOLL could reach \$10,000 to \$30,000 per megawatt-hour.[20] The second condition for well-functioning markets is that retail customers face the true cost of their electricity usage. That is to say, customers should see and pay higher prices on a per-kilowatt-hour basis when the VOLL is high than when the VOLL is low. Third, no participating firm should have the ability to exercise market power to inflate prices for its own benefit. And fourth, regulations governing the market should be stable and predictable over time.

Yet none of these conditions is fully met in the region's electricity market. When the New England markets were first restructured, wholesale prices were allowed to vary as needed to clear the market. But for four hours on the afternoon of May 8, 2000, high demand sent the prices up to \$6,000 per megawatt-hour—more than 200 times higher than the cost at midnight that day. A month later, NSTAR (the largest distribution company in Massachusetts) filed a complaint with FERC, arguing that the high prices meant the electricity market had serious design flaws. In response, the ISO imposed a cap of \$1,000 per megawatt-hour on what generators can charge, a cap that holds even if the market-clearing price would be much higher. This limit reduces the incentive for firms to invest in generating facilities, as many types of generating technologies rely on the revenue created during those hours of peak demand to recoup the fixed costs of their investment.

Second, even though wholesale prices vary significantly, retail customers face only limited exposure to this variation. As mentioned earlier, residential customers typically pay the same amount for each unit of energy consumed, and even commercial and industrial consumers do not face the full range of prices observed in the wholesale market. Electricity customers therefore have less incentive than they should to reduce their use at times of peak demand, further exacerbating the problems created by the \$1,000 bid cap.

Third, there have been at least a few cases in which firms have been able to exercise monopoly power over the market and to benefit from the resulting increased prices. Generators have done so by withdrawing electrical supply from the market at key times, so that the market-clearing price increases. If the generator has enough market power, the increase in revenues it receives from the increased price will offset the revenue it foregoes by producing less electricity. Firms are most likely to act as monopolists in load pockets, where high demand and lack of alternative sources of electricity mean that almost all generators are needed to meet demand. Facing little effective competition, every firm in the market has the power to influence prices. It is hard to know exactly how often monopoly behavior occurs, but the ISO's official independent market monitor found evidence that at least one large electrical generator in the Boston area had output gaps of up to 500 megawatts on a number of days in late 2004 and early 2005 when they normally would have been expected to be producing power. [21] While this firm's operations complied with ISO rules, such gaps could be viewed as leading to unfair prices if they were allowed to persist.

And finally, the regulatory environment has certainly not been stable. Since deregulation began in earnest in the mid-to-late 1990s, the Federal Energy Regulatory Commission, ISO New England, and the state regulatory agencies have been embroiled in regulatory proceedings and lawsuits over how deregulation should proceed. New organizations have been created (such as Independent System Operators and Regional Transmission Organizations); market structures have changed (for example, the $1,000 bid cap instituted in 2001); and pricing structures have been altered (such as the introduction of locational marginal pricing). Further, there are no agreed-upon rules, or "circuit breakers," built into the market structure regarding what kinds of regulatory changes are allowable under what circumstances, so it is difficult for firms to predict the conditions they are likely to face in the future.

If all four of the preceding conditions were met, the market would likely yield enough incentives for investment to ensure that society attained the socially optimal level of reliability. However, this is unlikely to happen in practice because legislators and the public would put pressure on regulators to protect consumers from price swings and supply shortages.[22] As a result, an electricity market in the real world is unlikely to yield a strong enough investment incentive to ensure sufficient reliability. Some level of reliability can certainly be created in private markets; for example, firms sign private contracts that provide them payments for shifting their demand at peak times, or they invest in backup generators. But since no single entity in New England is responsible for ensuring the system's reliability, no one has been willing to back long-term contracts that would create the investment needed to achieve the socially optimal level of reliability. In addition, electricity cannot effectively be stored, so there is no way to build up an "inventory" of electricity to act as a hedge against reliability problems. This is why, historically, regulators have set a technical planning standard for reliability—currently no more than one day in 10 years when electricity demand exceeds available capacity, as set by the North American Electric Reliability Council—rather than allowing it to be determined by the market.

Several parts of the region are experiencing high electricity demand, limited generating capacity, and restricted ability to import electricity from elsewhere.

Given these circumstances, firms have hesitated to invest in electrical generation capacity. The initial influx of money into the energy industry right after deregulation may have represented the combined effects of the promise of new market opportunities and the pent-up demand for investment stemming from the uncertainty of the previous few years. Once the parameters of deregulation had been established and the initial rush into the market ended, investors appear to have concluded that under today's market conditions, expected wholesale prices would be high enough to cover their variable costs of production, but not high enough to cover the fixed costs of the initial investment. In addition, because of strong community opposition in many areas to new electrical infrastructure, as will be discussed below, investors may have been concerned about their ability to site new facilities.

Wholesale electricity prices are not high enough to cover the fixed cost of investment.

Further investment has all but ceased, reducing planned capacity growth and putting system reliability at risk. Any new policy initiative to improve investment incentives should acknowledge the public-good nature of system reliability and should ensure that the structure of short-term energy markets aligns with the long-term goal of ensuring sufficient capacity.

Policies to improve incentives for investment

Regulators, generators, and the ISO alike agree that the incentives for investment in generation in New England are inadequate and poorly designed. The question is how to fix them. In April 2002, FERC requested that ISO New England develop a market-based mechanism to ensure adequate incentives for meeting reliability standards and future infrastructure needs. The ISO proposed a locational installed capacity market, known as LICAP. Under the proposal, the region would be divided into five geographical zones. The ISO would allocate payments within each zone based on an administratively set formula that reflects the fact that capacity is more valuable when it is more scarce, whether that scarcity is a result of high demand or insufficient supply. Thus, capacity prices, and therefore payments, would decrease as capacity increases. The formula would also help ensure reliability by paying not only for the capacity needed to meet day-to-day demand, but also for the additional capacity needed to ensure system reliability. In addition, the formula would reward all capacity with payments, whether that capacity was pre-existing or built in response to new market needs.

This proposal has met with nearly unanimous disapproval from regulators, consumer advocates, attorneys general—indeed, basically everyone in the energy community other than the ISO, the generators themselves, and the administrative law judge assigned to the proceeding. Critics are concerned about the potential for a large increase in costs to consumers, especially since the estimated costs vary widely across the different stakeholders in the dispute and some are quite high. For instance, the New England Power Generators Association has estimated a 3-percent average increase in costs to consumers stemming from LICAP,[23] while a report by the Associated Industries of Massachusetts (a business advocacy group) says that costs could increase by as much as 40 percent.[24] State governments moved toward deregulation partially on the grounds that it would decrease rates. Consequently, many are concerned about the political fallout from a sharp increase in rates. Critics also object to the fact that these high payments guarantee neither that additional capacity will be built nor that existing generators receiving payments will still be online later when their capacity is actually needed. Moreover, LICAP would reward not only those adding new generation capacity, but also those who are already in the market, creating what regulators view as a windfall for existing generators. LICAP's opponents also argue that the reliability standards are set too high, not at the one-event-in-10-years technical standard, but rather at a standard based on the average level of reserves over the last two decades. Critics of this standard consider it to be too high because it is based on a period of overbuilding. Enforcing such a reliability standard could force consumers to pay for a level of reliability higher than what is socially optimal.

The New England Conference of Public Utility Commissioners and several state public utility commissions have proposed alternatives designed to meet the problem of capacity incentives that, in their view, would be more cost-effective than LICAP, but the issue has yet to be resolved. A provision in the Energy Policy Act of 2005 expressed the sense of Congress that FERC should consider the views of states in the region in establishing LICAP. This, combined with a crescendo of mounting objections to the original proposal and timeframe, led FERC to order ISO New England to delay implementing LICAP until no earlier than October 1, 2006. On March 6, 2006, ISO New England, many of the region's generators, and four out of the six New England states submitted an agreement to FERC that attempts to resolve the concerns about LICAP. The agreement would create a forward capacity market, with the ISO responsible for creating three-year forecasts of capacity needs and conducting an annual auction to purchase power to meet those needs. The plan also allows prices to vary geographically depending on regional market conditions. The group submitting the proposal has requested FERC's approval by June 30. The agreement still faces opposition from the attorneys general of Connecticut and Massachusetts, as well as several state public utility commissions, so its future is still unclear.

Infrastructure siting

Even if policymakers find a way to improve the incentives to build new energy facilities, all of this infrastructure has to go somewhere—and this, too, has been a challenge for the region. Siting energy infrastructure is one of the most contentious issues in energy policy because it involves complicated tradeoffs among individual concerns, local and state authority, and regional and national needs. The fundamental economic problem is this: The benefits of energy infrastructure accrue regionally or even nationally, while the costs are borne locally. This tension is compounded in New England by the region's relatively high population density, which reduces the number of appropriate sites, and by its tradition of local control. As a result, even when all parties agree that new infrastructure is needed, and even when a new facility offers potential community benefits such as increased employment or property tax revenue, few communities may be willing to actually host those new generating plants, transmission lines, or gas terminals. Yet putting infrastructure in place is the linchpin of ensuring the reliability of the region's energy system.

The difficulties energy providers have encountered in attempting to site new natural gas facilities in the region, despite the clear regional need for more gas capacity, provide insight into the challenges of the process. For example, several energy suppliers have proposed building liquefied natural gas receiving terminals, either onshore or several miles out into the ocean, which would serve the New England region. The proposal currently farthest along in the regulatory approval process would construct a liquefied natural gas facility on the location of a former oil refinery along the shoreline of Fall River, Massachusetts, in Weaver's Cove. As proposed, the facility would be able to accept LNG from oceangoing tankers and could turn out approximately 400 million cubic feet of vaporized natural gas per day (up to 800 million cubic feet on peak demand days).[25] The project developer, Weaver's Cove Energy, says this could cover 15 to 20 percent of the region's gas needs, helping to improve system reliability and to support peaking capacity. Locating such a

Regulators, generators, and the ISO alike agree that the incentives for investment in generation in New England are broken.

facility at Weaver's Cove could also economize on the costs of transporting gas to final consumers, because the site is close to both the existing natural gas pipeline and the largest concentration of demand for gas (primarily in Connecticut, Massachusetts, and Rhode Island). The project would cost approximately $250 million. FERC approved the terminal on June 30, 2005, conditional upon further documentation of provisions for its safety and security.

Local communities, however, are increasingly unwilling to accept new energy infrastructure within their borders, and the Weaver's Cove project has been no exception. The project has met with strong opposition from the citizens of Fall River and from state and federal politicians. The mayor of Fall River has vocally opposed the plan, saying, "We'll kill this project with a thousand paper cuts." The Massachusetts and Rhode Island governors and attorneys general and most of the two states' congressional delegation have joined his opposition, along with the Conservation Law Foundation, the U.S. Navy (which is concerned about the project's impact on its nearby Shallow Water Test Facility), and a number of local community groups.

In many cases, a siting board's geographic span of control does not coincide with the geographic impact of the project.

As with many proposed LNG facilities, much of the community's apprehension about Weaver's Cove stems from concerns about safety and security—the potential for spills at the facility to destroy property and injure or kill nearby residents. A recent study by the Sandia National Laboratories found that the risks of accidental or intentional spills are low and manageable with proper procedures, especially since LNG is flammable only when mixed at 5 percent to 15 percent concentrations with air. But the study also noted that if a spill were to happen, "major injuries and significant damages to property" could occur within about a one-mile radius of a breach—particularly if the spill were initiated by a planned attack and risk mitigation procedures were not in place.[26] A FERC report on the proposed Weaver's Cove terminal notes that "approximately 12,000 people living in 5,100 housing units are located within one mile of the proposed LNG tank."[27] Local residents are also concerned about the impact on the fishing industry, marine recreation, and tourism. Unlike some other projects, however, the visual impact of the facility is not a major issue, since it would be located in an industrial zone that has long been the site of energy infrastructure. (Visual impact tends to be more significant when proposed facilities would be sited in areas where none existed before.)

Most of the other proposed LNG facilities throughout the region have also encountered snags in the siting process. In the same ruling in which FERC approved Weaver's Cove, the Commission turned down a proposal to build an LNG facility in Narragansett Bay, Rhode Island, saying, "the facility would not meet current construction and safety standards".[28] The Maine-based Passamaquoddy Native American tribe attempted to attract an LNG facility to its Pleasant Point reservation, but opposition from the surrounding community and some tribal members was strong, and the project was cancelled after it lost a referendum vote in the nearby town of Perry. While the town of Robbinston, Maine, recently approved a potential LNG facility in Passamaquoddy Bay, three other LNG proposals in Maine's Casco Bay have been rejected by local communities. And in Gloucester, Massachusetts, local fishermen have opposed two separate proposed offshore LNG terminals, concerned about the facilities' potential impact on the fishing industry.

Ideally, the siting process would be the mechanism by which these local concerns are balanced with regional needs. The process is intended to provide opportunities for public comment and for expert reviews of impact, as well as for an evaluation of the public benefits and costs of the project. But this is not always a straightforward process since in many cases, a siting board's geographic radius of control does not fully encompass the geographic scope of the project's impact. Local siting boards therefore tend to be more sensitive to local than to regional concerns. A new facility might benefit (or alternatively, might adversely impact) several neighboring towns, for example, but only the town in which it is located is likely to have much influence over the project's approval. For instance, in the case of Weaver's Cove, even though the regional need for more natural gas infrastructure is well known, the towns of Fall River and Somerset, Massachusetts, have denied permits to the developer for terminal construction and dredging. The advantage of the current siting process is that it gives those who bear the greatest costs from a particular project—localities—the greatest say in its approval or denial. But if every town can say no, then who will say yes? At the extreme, the process could sacrifice regional reliability for the sake of local control.

Things become even more complicated when the infrastructure in question falls in the gray area among local, state, and federal spheres of authority. FERC has regulatory authority over the terms and conditions of interstate transmission of electricity, as well as the rates, terms, and conditions of interstate gas deliveries such as LNG terminals and pipelines. But states and localities can intercede if the project does not meet certain state standards or the conditions of the Coastal Zone Management Act, the Clean Air Act, or the Federal Water Pollution Act. The Weaver's Cove project, for instance, has received approval from FERC, as well as denial of a request for a rehearing from the project's opponents. But the developers must still obtain several state approvals, most significantly for dredging, and must successfully appeal the local permit denials before they can begin building. They also must find a way around language that was slipped into a recent federal transportation bill to stop the demolition of a bridge that currently prevents large LNG tankers from reaching the Weaver's Cove site. (Rather than have Congress try to reverse the language, the developers now propose to use smaller tankers; but this approach has not yielded any greater enthusiasm from the local community.) Localities are required to act within the terms and conditions of the authority delegated to them by the federal government, so local decisions against new infrastructure can be challenged. But this process can add lengthy and expensive delays, and the multiple layers of approval involved can generate confusion about whether the local, state, or federal government is the ultimate decision maker. This is why the Energy Policy Act of 2005 felt it necessary to clarify that FERC, rather than state governments, has the final authority with respect to natural gas facility siting.

While some of the steps in the siting process are clearly necessary in order to protect the public interest, their cumulative effect may be indirectly undermining the reliability of the energy system—which is also in the public interest. Further, there is currently no coordinated way for federal, state, and local officials to consider all the infrastructure proposals within the region and decide collectively which are most appropriate given regional needs and community concerns. Until these issues are resolved, the process for siting new energy infrastructure in the region will continue to be long and arduous, and the region will continue to find it difficult to build sufficient capacity for its reliability needs.

Fueling New England's energy future

Government and markets have long worked together to create a reliable energy system for New England. Businesses have invested in technologies and infrastructure, from waterwheels to power plants, that have increased the region's productivity and fostered economic growth. And government has helped ensure that the benefits of these technologies are broadly available, that firms have sufficient opportunity to earn back their investments, and that firms invest enough to ensure a reliable system.

At the moment, however, this relationship shows evidence of fraying. Increasing demand for natural gas has left the region more open to effects from price swings in world gas markets. The deregulated structure of the region's wholesale electricity market has led to insufficient capacity in some areas within the region, in part by making it difficult for generators to earn back their capital investments. And competing spheres of authority across federal, state, and local governments, combined with public concerns about the safety and security of energy infrastructure and a relative paucity of appropriate sites for development, have made siting new power plants, transmission lines, and pipelines within the region extremely challenging. All these trends have put the reliability of the region's energy system at risk.

Businesses and government must work together to surmount New England's energy problems. This will not be easy, but it is critical for the region's economic prosperity.

New England's state governments can and should take a more active role in ensuring system reliability. They can help maintain the region's fuel diversity by responding to the region's dramatic growth in natural gas demand and by experimenting with incentives to promote renewable energy sources and new technologies. They can reduce demand through new energy pricing structures and energy efficiency programs. They can work with ISO New England and energy regulators to improve the incentives for investing in electrical generation. And they can smooth the process of siting new infrastructure so that community, regional, and national considerations are all given due weight.

New England's energy problems were not quickly created, and they will not be quickly resolved. In order to surmount them, firms must invest in the right kind of infrastructure in the right place and at the right time, and government must ensure that system reliability is not given short shrift in the process. This will not be easy, but it is critical for the region's future. Without the assurance of an energy system that can meet immediate demands along with long-term growth, the region puts its economic prosperity at risk.

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Regulatory Assistance Project
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Glossary

Biomass: Organic nonfossil material of biological origin constituting a renewable energy source.

Capacity factor: The ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period.

Combined cycle: An electrical generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat-recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electrical generating unit.

Current (electric): A flow of electrons in an electrical conductor. The strength or rate of movement of the electricity is measured in amperes.

Diesel fuel: A fuel composed of distillates obtained in petroleum refining operation or blends of such distillates with residual oil used in motor vehicles. The boiling point and specific gravity are higher for diesel fuels than for gasoline.

Distillate fuel oil: A general classification for one of the petroleum fractions produced in conventional distillation operations. It includes diesel fuels (No. 1, No. 2, and No. 4), used in transportation, and fuel oils (No. 1, No. 2, and No. 4), primarily used for space heating and electric power generation.

Distribution: The delivery of energy to retail customers.

Dual-fired unit: A generating unit that can produce electricity using two or more input fuels. In some of these units, only the primary fuel can be used continuously; the alternate fuel(s) can be used only as a start-up fuel or in emergencies.

Electric power grid: A system of synchronized power providers and consumers connected by transmission and distribution lines and operated by one or more control centers. In the continental United States, the electric power grid consists of three systems: the Eastern Interconnect, the Western Interconnect, and the Texas Interconnect. In Alaska and Hawaii, several systems encompass areas smaller than the State (e.g., the interconnect serving Anchorage, Fairbanks, and the Kenai Peninsula; individual islands).

Electric system reliability: The degree to which the performance of the elements of the electrical system results in power being delivered to consumers within accepted standards and in the amount desired. Reliability encompasses two concepts, adequacy and security. Adequacy implies that there are sufficient generation and transmission resources installed and available to meet projected electrical demand plus reserves for contingencies. Security implies that the system will remain intact operationally (i.e., will have sufficient available operating capacity) even after outages or other equipment failure. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service.

Electric utility: A corporation, person, agency, authority, or other legal entity or instrumentality aligned with distribution facilities for delivery of electric energy for use primarily by the public. Included are investor-owned electric utilities, municipal and state utilities, federal electric utilities, and rural electric cooperatives. Also included are a few entities that are tariff based and corporately aligned with companies that own distribution facilities.

End user: A firm or an individual that purchases products for his/her own consumption and not for resale (i.e., an ultimate consumer).

Energy-use sectors: A group of major energy-consuming components of U.S. society developed to measure and analyze energy use. The sectors most commonly referred to in EIA are: residential, commercial, industrial, transportation, and electric power.

Fossil fuel: An energy source formed in the Earth's crust from decayed organic material. The common fossil fuels are petroleum, coal, and natural gas.

Fuel oil: A liquid petroleum product less volatile than gasoline, used as an energy source. Fuel oil includes distillate fuel oil (No. 1, No. 2, and No. 4), and residual fuel oil (No. 5 and No. 6).

Gasification: A method for converting coal, petroleum, biomass, wastes, or other carbon-containing materials into a gas that can be burned to generate power or processed into chemicals and fuels.

Generator capacity: The maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, adjusted for ambient conditions.

Geothermal energy: Hot water or steam extracted from geothermal reservoirs in the Earth's crust and used for geothermal heat pumps, water heating, or electricity generation.

Integrated gasification combined cycle (IGCC) technology: Coal, water, and oxygen are fed to gasifier, which produces syngas. This medium-Btu gas is cleaned (particulates and sulfur compounds removed) and is fed to a gas turbine. The hot exhaust of the gas turbine and heat recovered from the gasification process are routed through a heat-recovery generator to produce steam, which drives a steam turbine to produce electricity.

Liquefied natural gas (LNG): Natural gas (primarily methane) that has been liquefied by reducing its temperature to –260 degrees Fahrenheit at atmospheric pressure.

Load (electric): The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of consumers.

Net interstate flow of electricity: The difference between the sum of electricity sales and losses within a state and the total amount of electricity generated within that state. A positive number indicates that more electricity (including associated losses) came into the state than went out of the state during the year; conversely, a negative number indicates that more electricity (including associated losses) went out of the state than came into the state.

Primary energy: All energy consumed by end users, excluding electricity but including the energy consumed at electric utilities to generate electricity.

Renewable energy resources: Energy resources that are naturally replenishing but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Renewable energy resources include: biomass, hydroelectric, geothermal, solar, wind, ocean thermal, wave action, and tidal action.

Transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Transmission and distribution loss: Electric energy lost due to the transmission and distribution of electricity. Much of the loss is thermal in nature.

Underground gas storage: The use of subsurface facilities for storing gas that has been transferred from its original location. The facilities are usually hollowed-out salt domes, geological reservoirs (depleted oil or gas fields), or water-bearing sands topped by an impermeable cap rock (aquifer).

Waste energy: Municipal solid waste, landfill gas, methane, digester gas, liquid acetonitrile waste, tall oil, waste alcohol, medical waste, paper pellets, sludge waste, solid byproducts, tires, agricultural byproducts, closed-loop biomass, fish oil, and straw used as fuel.

Wholesale electric power market: The purchase and sale of electricity from generators to resellers (retailers), along with the ancillary services needed to maintain reliability and power quality at the transmission level.

Wood energy: Wood and wood products used as fuel, including round wood (cord wood), limb wood, wood chips, bark, sawdust, forest residues, charcoal, pulp waste, and spent pulping liquor.

Key measuring units

Barrel: A unit of volume equal to 42 U.S. gallons.

British thermal unit (Btu): The quantity of heat required to raise the temperature of one pound of liquid water by one degree Fahrenheit at the temperature at which water has its greatest density (approximately 39 degrees Fahrenheit).

Cord of wood: A cord of wood measures 4 feet by 4 feet by 8 feet, or 128 cubic feet.

Cubic foot (cf), natural gas: The amount of natural gas contained at standard temperature and pressure (60 degrees Fahrenheit and 14.73 pounds standard per square inch) in a cube whose edges are one foot long.

Metric ton: A unit of weight equal to 2,204.6 pounds.

Short ton (coal): A unit of weight equal to 2,000 pounds.

Watt (W): The unit of electrical power equal to one ampere under a pressure of one volt. A watt is equal to 1/746 horsepower. Kilowatt (kW): 1,000 watts. Megawatt (MW): 1 million watts.

Watt-hour (Wh): The electrical energy unit of measure equal to one watt of power supplied to, or taken from, an electric circuit steadily for one hour. Kilowatt-hour (kWh): 1 kilowatt (1,000 watts) of power expended for one hour. Megawatt-hour (MWh): 1,000 kilowatt-hours or 1 million watt-hours.

Common energy units

Energy Unit	Btu Content	If used for electricity (at 100% efficiency)
1 cubic foot of natural gas	1,031 Btu	0.3 KWh
1 short ton of coal	20,754,000 Btu	6,080 KWh
1 standard cord of wood	20,000,000 Btu	5,860 KWh
1 barrel (42 gallons) of crude oil	5,800,000 Btu	1,700 KWh
1 gallon of middle distillate or diesel fuel oil	38,690 Btu	
1 gallon of kerosene or light distillate oil	135,000 Btu	
1 gallon of gasoline	124,071 Btu	
1 kilowatt-hour of electricity	3,412 Btu	

Source: Energy Information Administration and author's calculations.

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