Recent Electricity Market Reforms in Massachusetts

A Report of Benefits and Costs

Executive Office of Housing and Economic Development
Executive Office of Energy and Environmental Affairs

July 2011

To the People of Massachusetts:

At the direction of the Legislature, we have prepared this report on the costs and benefits of recent state requirements on our electricity markets. We have organized our report on three categories of recent state requirements: 1) energy efficiency; 2) renewables and alternative energy; and, 3) innovation and sector development.

The major conclusions of the report are as follows:

- For the past several decades the cost of electricity in Massachusetts, and in most other New England states, has been considerably higher than in the rest of the country. Our higher costs are not related to recent state legislation and requirements, but rather due to the fact that Massachusetts has virtually no indigenous energy resources, requiring us to import almost all of our energy resources from outside the region or overseas. Nonetheless, the three different categories of recent state requirements do create costs and benefits for electricity ratepayers.

- **Energy Efficiency:** Of the recent state requirements, the policies mandating utility company investments in energy efficiency provide the largest cost savings for consumers for the dollars invested. Of all the clean energy programs, they impose the greatest upfront cost, constituting more than 75% of the additional cost imposed on ratepayers, but show returns on investment of the order of $3 savings for each dollar investment. Through these programs residential and business customers are significantly lowering their electricity bills. .

- **Renewables and Alternative Energy:** The state requirements mandating that a percentage of all electricity generation be by clean or renewable energy allow utilities to meet these requirements by finding and securing the lowest-cost renewable energy sources. These requirements are producing cost savings for ratepayers, primarily through suppression of the electricity clearing price, that substantially exceed program costs.

- **Innovation and Sector Development:** The state requirements that mandate investments in local energy generation initiatives, including locally-generated solar and offshore wind, do not produce an immediate direct economic benefit to all ratepayers that offsets their costs. Instead, the economic return on these investments also needs to be measured in terms of the number of local employment opportunities created and the non-quantified benefits from diversifying our generation resource away from traditional fossil fuel based sources and incorporating more dispersed local distributed resources in our electricity system. Further study would be needed to provide a rigorous estimate of those employment gains and other non quantified benefits, taking into account any potentially offsetting employment losses in other industry sectors due to higher electricity prices. The available information, however, indicates a rapid growth in local employment to date (on the order of thousands of new jobs and the growth of hundreds of new businesses),,and quite a marginal effect of these investments on the overall cost of electricity.

In our opinion, these conclusions lead us to recommend the following further actions:

- Energy efficiency programs continue to be and will remain into the foreseeable future the “cheapest new source of electricity.” Expansion of these investments by ratepayers will continue to result in long-term savings for residential and business customers.

- It should be a continuing priority of state government to partner with our universities and with industry in making Massachusetts a global center for the development of clean energy and energy efficiency innovations that are lower cost than those currently available today.

- Our initiatives to increase the percentage of electrical generation by clean or renewable energy should incorporate the opportunities presented by potentially lower-cost energy sources, including on-shore wind in Northern New England and hydro from Eastern Canada, as long as contracts are based on our competitive wholesale market and that transmission costs are not socialized.

- On-going data collection should be undertaken to allow continuing analysis of the projected employment gains from the growth of our clean energy industry cluster, taking into account any potentially offsetting employment losses.

Sincerely,

Gregory Bialecki	Richard K. Sullivan Jr.
Secretary	Secretary
Executive Office of	Executive Office of
Housing and Economic Development	Energy and Environmental Affairs

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Introduction and Executive Summary

The Executive Office of Housing and Economic Development (EOHED), in consultation with the Executive Office of Energy and Environmental Affairs (EOEEA), has compiled a report of the benefits and costs of recent electricity market initiatives, as required by Section 185 of the Economic Development Reorganization Act — Chapter 240 of the Acts of 2010, signed by the Governor on August 5, 2010. This report, which incorporates input from stakeholders representing various sectors of the Commonwealth's economy, reviews the costs and benefits associated with recent administrative, regulatory, and legislative changes related to electricity, including their impacts on rates and bills of electricity customers and their impact on economic development in the state.

For context, this report provides a primer on the market for electricity in Massachusetts and New England, with a focus on the post-restructuring period (since 1998), and how the realities of our competitive wholesale electricity market are reflected in the electric bills paid by large business customers, in particular. Notably, Massachusetts (along with the other New England states) has long had high electricity prices relative to other states, especially those that get much of their electricity from local sources of coal and hydropower. Nationally, up to 80% of the variability in electricity prices across states can be explained by decades-old decisions and fuel prices.

The 1997 Electric Restructuring Act changed the way the electric utility industry is structured, requiring traditional, "vertically integrated" electric utilities to remove themselves from the power generation business. As a result, the power generating capital stock in New England has come to reflect the dynamics of a competitive market. At a time of low gas prices in the late 1990s, almost 100% of new power generation capacity initiated in New England was fired by natural gas. The switch from residual oil and coal to cleaner burning natural gas had the benefit of substantially reducing the impact of power generation on air quality and climate, but left the market — and customers — vulnerable to swings in natural gas prices. It is important to note, however, that 12 percent of the Commonwealth's electricity generation is still fueled by coal. Although not reflected directly on ratepayers' bills, the costs of coal - including environmental degradation and resulting human health impacts- have been borne by citizens for decades through various mechanisms, including health insurance premiums and taxes in the form of long-standing federal government support for the fossil fuel industry.

With the Green Communities Act, the Global Warming Solutions Act, and the Green Jobs Act of 2008, the Governor and the General Court established a comprehensive energy market policy for the Commonwealth of Massachusetts, updating the market framework established by the Restructuring Act to give it a new and more explicit public purpose encompassing energy security, cleaner energy resources, and economic development resulting from the transition to a clean energy future. The initiatives mandated by or developed in response to these laws are grouped in to four categories:

- Energy Efficiency,
- Renewable and Alternative Energy,
- Clean Energy Imports and Transmission, and
- Innovation and Sector Development

Each category has attendant costs and benefits. This report examines these costs and benefits in terms of electric customer bill impact, using well established methodologies. This report also discusses potential job impacts, both positive and negative, though extensive analysis of this topic was beyond the scope of this report and will require future study. This report does not address any related public health impacts.

This report shows that when all initiatives are fully implemented in 2015, the total benefits to electric customers of all four initiative categories will be $2.5 billion - nearly two and half times as great as the $1.1 billion cost of implementing the initiatives. This strong positive return on investment is a prudent investment for ratepayers and the Commonwealth. When compared to the estimated $8.4 billion spent on electricity in Massachusetts in 2009 (and over $9 billion in 2008, when natural gas prices were at their recent peak), the resources committed to the comprehensive energy market policy are modest and promise direct benefits to ratepayers and the Commonwealth as a whole.

Electricity Market and Electricity Bills Primer

Over the three decades from 1977 to 2007, electricity markets and regulation at the state, regional, and Federal levels evolved substantially. Each region's electricity markets were shaped by a number of factors, such as local natural resources and regulatory choices, resulting in different retail price patterns. Figure 1 shows how three New England states, three Mid-Atlantic states, Texas, and California — includes several states that compete with Massachusetts in the innovation economy — had similar price trends for large business customers over the past 20 years, despite variation in state-specific prices.

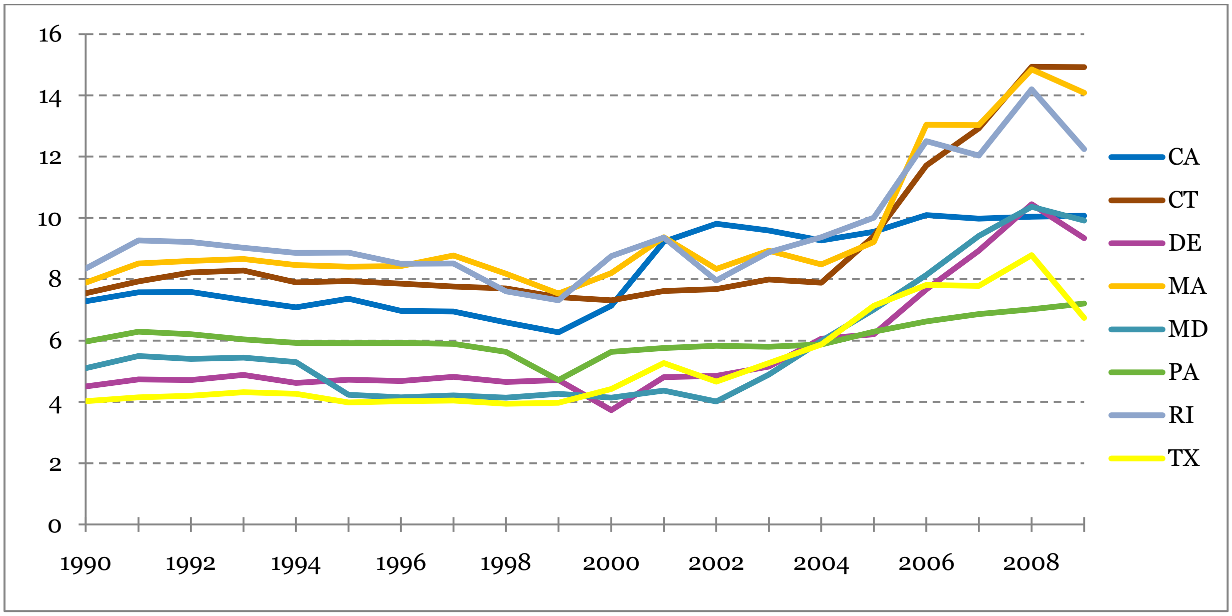


Figure 1 — Electricity Prices for Large Business Customers in Several States in cents per kilowatt-hour (1990 – 2009)
Source: U.S. Energy Information Administration (EIA)

The six New England states stand out for having some of the highest average electricity prices in the nation throughout this period, which ends before the implementation of the market reforms enabled by the Green Communities Act of 2008. For example, in 1990, the New England states were all in the top 11 states in the nation for electricity prices, with Massachusetts third highest. In 2007, the New England states were all in the top 13, with Massachusetts still ranking third.

The factors that cause variations in any state's electric prices are well-studied. A widely-cited 2006 study of electricity markets by a Massachusetts Institute of Technology (MIT) economist analyzed the relationship between retail electricity prices for industrial customers and various factors across states over a 33-year period from 1970 to 2003.[1] The study used statistical analysis to discern exactly what factors cause variations in electricity prices. The statistical models developed are very robust and explain up to over 80% of the variation in electricity prices. The study found that two sets of factors had the most significant impact on retail prices in different states. One group of factors related to the resource mix:

- Higher share of total electricity coming from hydroelectric generation resulted in lower prices, reflecting the lower operating costs of hydro plants;
- Lower average fossil fuel prices resulted in lower electricity prices, reflecting the lower operating costs that come with lower cost fuels; and

- Higher share of total electricity coming from nuclear generation resulted in higher electricity prices, reflecting the unexpectedly large capital cost of many of the nuclear plants built.

The other group of factors related to policy variables:

- Higher share of total electricity generation coming from "Qualifying Facilities" under the Federal Public Utilities Regulatory Policy Act (PURPA) resulted in higher electricity prices.
- Higher share of electricity generated by unregulated generators, i.e. wholesale market competition, resulted in lower electricity prices.

In addition to the explicit policy variables in the second set of factors, it is also important to consider implicit policy variables in the first set. Most large hydro plants were built before 1980 either by the federal government or with its support. Thousands of megawatts of this capacity continue to be operated today, with a zero-cost renewable "fuel," low operating costs, and fully depreciated capital.

Coal is another fuel that has low prices in part because of substantial federal subsidies, both explicit and implicit. One example is the "Credit for Production of Nonconventional Fuels," from Section 45K of the Internal Revenue Code, which resulted in $14 billion in subsidies from 2002 to 2008, largely awarded to coal producers.[2] In addition, a study by the National Research Council of the National Academy of Sciences, *The Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use*, monetized the impact of major air pollutants, not counting climate impacts. The study found that, for coal-fired power plants, non-climate damages average about 3.2 cents per kWh, with human health and premature mortality being the largest component.[3] The estimated pollution cost of natural gas was just 5% of this number. A more recent study from the Harvard Medical School Center for Health and Global Environment finds that the life cycle of coal-extraction, transport, processing, and combustion carries multiple hazards for health and the environment with costs to the public estimated at 9 to 27 cents per kWh.

Some business interests have correctly pointed out that MA large business electricity costs are much higher than states with much lower electricity costs such as Washington, Utah, Iowa and North Carolina. This price disparity is not a new phenomenon. Figure 2a shows the disparity in electricity prices for large business customers over the past 20 years between Massachusetts and four states that have among the lowest electricity prices in the nation. The long-standing difference in electricity prices — and the dramatic growth in that difference from 2005 to 2008 — can be largely explained by the factors cited above: differences in fuel resources and federal subsidies. For example, as shown in Figure 2b, Utah's electricity mix is over 80% coal power and Washington's is over 70% hydro power. In contrast to these states, New England's electricity mix is over 40% natural gas and has less than 15% coal and 8% hydro. This makes states like Utah attractive locations for energy-intensive businesses. In the past year, Utah has been chosen for several large data centers, for which electricity is a major cost, including those operated by the National Security Agency, Ebay, and Twitter.

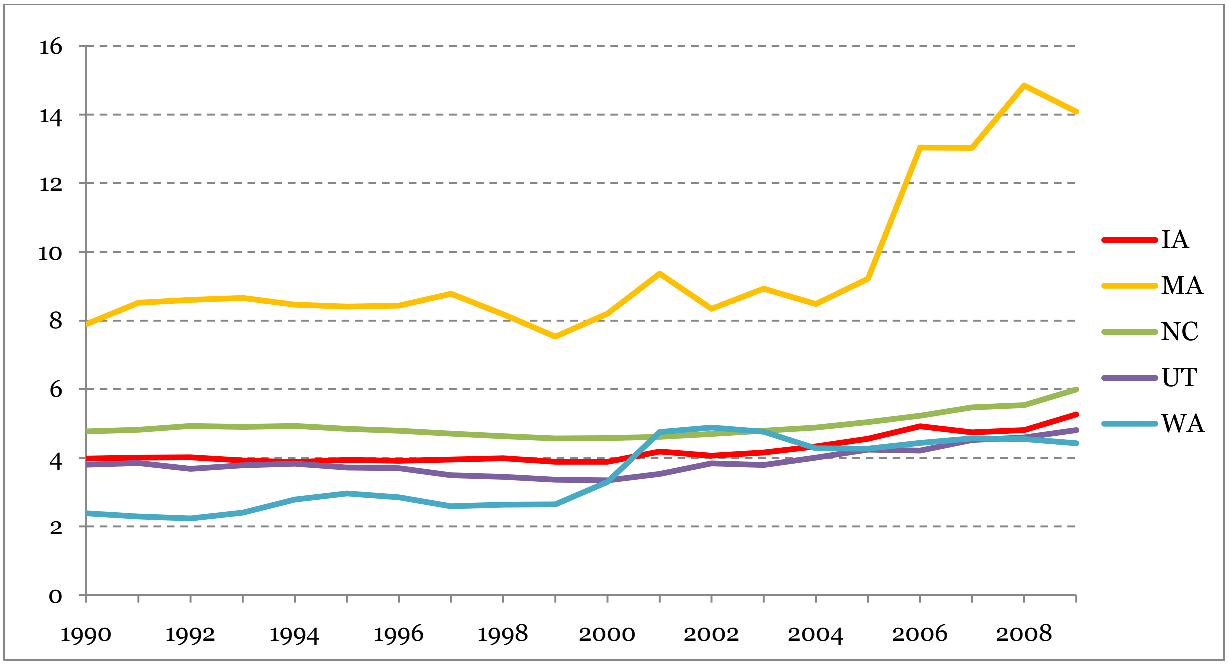
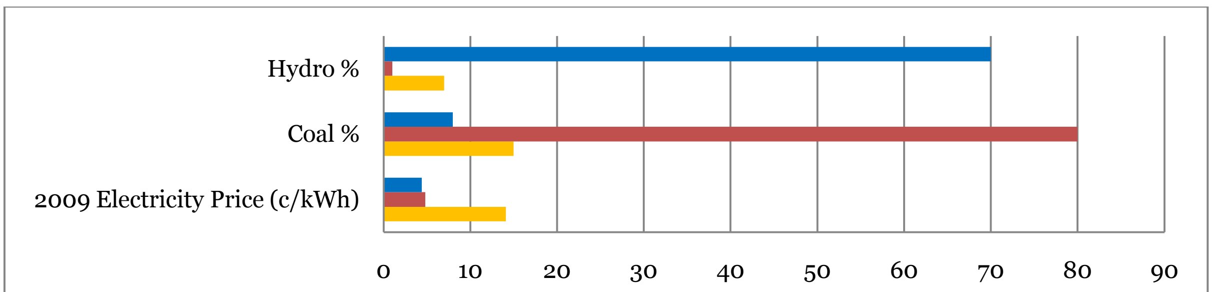


Figure 2a — Electricity Prices for Large Business Customers in MA and Four Low-Priced Electricity States in cents per kilowatt-hour (1990 – 2009)
Source: EIA



	2009 Electricity Price (c/kWh)	Coal %	Hydro %
WA	4.4	8	70
UT	4.8	80	1
MA	14.1	15	7

Figure 2b — Electricity Prices in Selected States Relative to Electricity Mix
Source: EIA

Electricity Restructuring and Prices

In the 1990s, Massachusetts, like many other states, undertook the process of creating a competitive electricity market. The 1997 Electric Restructuring Act changed the way the electric utility industry is configured, other than for municipally-owned utilities. The Restructuring Act required traditional, "vertically integrated" electric utilities to remove themselves from the power generation business, making them divest themselves of their power plants. They continue to operate as distribution companies, purchasing electricity from competitive power suppliers and maintaining the power wires and poles that deliver it to customers. Today, there are four investor-owned distribution companies in Massachusetts:

National Grid, NSTAR, Western Massachusetts Electric Co., and Unitil. A competitive power supplier, also known as "power producer" or "power generator," is a company or group that creates and sells the electricity that is delivered to homes or (more typically) businesses by electric distribution companies.

Figure 3 shows that Commercial and industrial (C & I) customers have taken full advantage of the opportunities in Massachusetts's competitive electric markets with 90% of their load being served by competitive electricity suppliers.

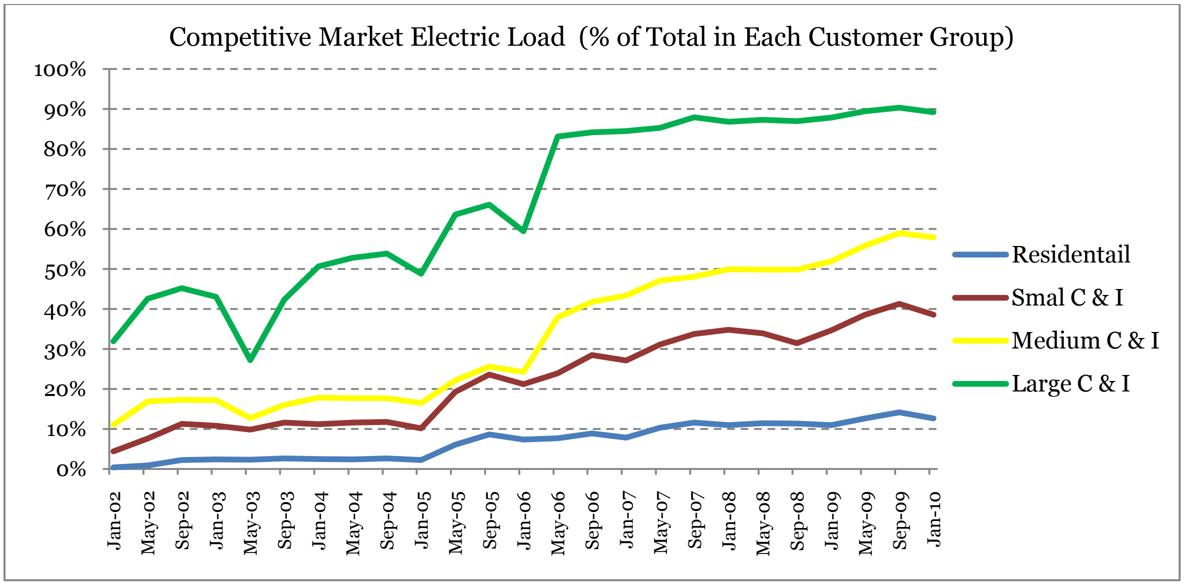


Figure 3 — Competitive Market Electric Load in Massachusetts by Customer Group
Source: DOER

Thus, while power sources in Utah and Washington reflect low-cost fuel resources and federal government support, the power generating capital stock in New England reflects the dynamics of a competitive market.

At a time of low gas prices in the late 1990s, almost 100% of new power generation capacity initiated in New England was fired by natural gas. Nearly 10 GW of new natural-gas power plants were installed between 1999 and 2004, nearly *one-third* of current New England generation capacity. The switch from residual oil and coal to cleaner burning natural gas had the benefit of substantially reducing the impact of power generation on air quality and climate. As shown in Figure 4, Massachusetts ranks 37th out of the 50 states and the District of Columbia in CO_2 emissions.

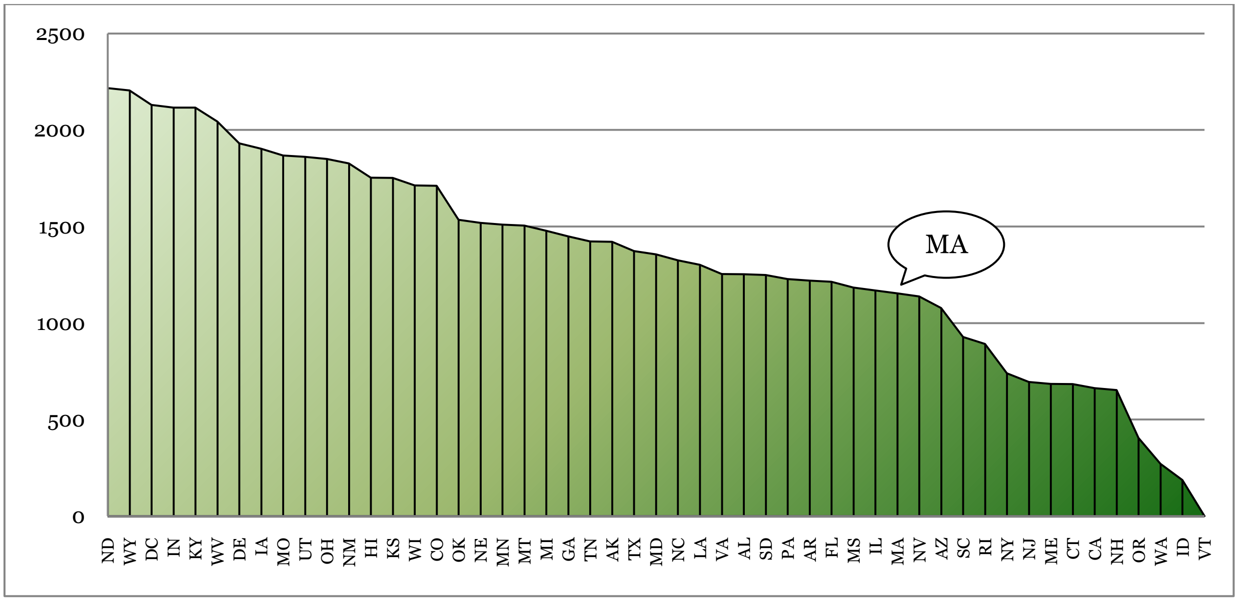


Figure 4 — CO2 Emissions by State in lbs per MWh
Source: EIA

When natural gas prices spiked from $4 to $12 between 2003 and 2006 and then again in 2008 and part of 2009, however, the price of power in New England shot up as well.

While restructuring electricity markets shifted risk from ratepayers to the market, there were trade-offs — namely, that retail electricity prices tended to be determined by the highest-price operator in the spot wholesale electricity market at a given time, rather than by a mix of generating sources owned by an integrated utility. The MIT study explained these trade-offs in the following way:

> *Under cost-of-service regulation, natural gas price increases would have been reflected in retail prices in proportion to the fraction of generation accounted for by gas-fired capacity under cost-of-service regulation. Deregulation removes this hedge, making wholesale prices more sensitive to variations in the prices for fuel used by the marginal generating capacity that clears the market. If natural gas prices stay very high, it may turn out to be the case that in the short run, the costs of purchasing generation supplies out of competitive wholesale markets will be higher than the costs consumers would have paid under regulation as the rents associated with unregulated hydro, nuclear and coal capacity will now accrue to the owners of this capacity rather than to consumers as a consequence of the loss of this regulatory hedge. On the other hand, under regulation when there was excess capacity, prices rose to allow recovery of fixed costs while with competition excess capacity should lead to lower prices, other things equal. Consumers also were asked to pay for large generating plant construction cost overruns under regulation, while with competition it's the investors that bear construction cost overrun risks.*

It is unknown what course New England power prices will take in the future. Some believe we have entered a new era of low natural gas prices due to new sources of supply, which will keep electricity prices down. Others say that view is distorted by the recent worldwide recession, and that the demand pressures that drove up electricity prices for Massachusetts customers in a four-fold increase between 1998 and 2008 will return. It is also possible that federal pollution regulation will reduce regional price disparities by cracking down on coal, with its high emissions of greenhouse gases and other pollutants, making New England's cleaner electricity mix more cost-competitive in the coming years.

Electric Utility Bills

The Restructuring Act changed the components that customers see on their utility bills. Following restructuring, a typical Massachusetts customer's electric bill contains two parts; the delivery services and the supply services. For business customers, the bill typically has the following components:

Delivery Services
RATE Business Time-of-Use (G-3)
- Customer
- Distribution Demand
- Distribution
- Transmission
- Transition
- Energy Efficiency
- Renewable Energy

Supplier Services
- Generation

Customers pay a distribution charge for the delivery of electricity to their door via local power lines. This charge also includes metering, billing and other customer services. Distribution rates are subject to the sole jurisdiction of the Massachusetts Department of Public Utilities (DPU). If an electric distribution company seeks to increase its distribution rate, it must apply to the DPU and subject its costs and revenues to regulatory scrutiny in a rate case. In addition to the distribution charge that is based on the *amount* of electricity consumed, the bill includes a customer charge that is fixed and, for commercial and industrial customers, a distribution demand charge that is based on the highest *rate* of electricity consumption for that customer.

The transmission charge is the cost of delivering electricity over high-voltage lines running from power-generating facilities to electric substations, where it enters the distribution system and travels over local power lines to individual homes and businesses. The Federal Energy Regulatory Commission (FERC) sets rates for transmission. The Massachusetts DPU then oversees the incorporation of the federally approved transmission cost into the rates that distribution companies in the Commonwealth charge their customers.

The transition charge is a fixed cost associated with utilities divesting themselves of power generating properties they formerly owned, as required by the 1997 Electric Restructuring Act. The transition charge is reviewed and reconciled each year by the DPU.

In addition, each customer's bill contains two charges related to clean energy programs originally established with the Restructuring Act and updated by the Green Communities Act. These Energy Efficiency and Renewable Energy charges fund the Commonwealth's energy efficiency and renewable energy programs, to be discussed later.

The generation charge reflects the cost of generating the amount of electricity that a customer actually uses. This represents the largest portion of a customer's electric bill. Consumers are free to choose their power-generating company, though large business and institutional customers are more likely to have more than one power supplier to choose from than are residential customers. For the many customers who do not select a particular power generator, the generation charge is based on their distribution company's "basic service" rate, which is applied per kilowatt hour (kWh). These rates are set by the competitive marketplace, resulting from private contracts entered into through periodic procurements by the distribution utilities and spot purchases in the wholesale electricity market, which is regulated by FERC and administered by the regional grid operator ISO-New England (ISO-NE).

Electricity Prices within Massachusetts

Electricity prices also vary within Massachusetts, albeit to a lesser extent than across states. At the request of the Legislature, the Department of Energy Resources (DOER) conducted a study on municipal light plants that included a comparison of electricity prices for municipal and investor-owned utilities.[4] The study found that differences in the financing costs and taxes for public and private entities had an impact on *distribution* rates. More significantly, the study found that differences in *supply* rates stemmed from historical long-term supply contracts or generation assets that certain municipal utilities retained under the Restructuring Act of 1997, the benefits of which they had the ability to pass on to customers at below-market prices. Investor-owned utilities, on the other hand, were required to divest themselves of such assets and buy electricity supply in a competitive marketplace.

As a result of these factors, municipal utilities have delivered electricity prices to their customers lower than those offered by investor-owned utilities. But this result was not ordained and will not necessarily occur in the future. Had market prices dropped as a result of new generation entrants and fuel prices, the relative prices between vertically-integrated municipal utilities and restructured investor-owned utilities would have turned out differently. Even today, if natural gas prices remain low and historical municipal contracts expire, municipal utility customers may see sharp price increases that bring their prices into line with the market. While it is impossible to predict exactly how these factors will play out in the future, it is clear that the Restructuring Act represents a commitment to a competitive marketplace and a choice to shift risk (and the associated return) from ratepayers to the market.

In one example of the implications of such electricity price differences within the state, five Massachusetts universities—Harvard, MIT, Boston University, Northeastern, and UMass—chose, along with their technology partners Cisco and EMC, to site a new high-performance computing facility in Holyoke. Holyoke Gas and Electric is able to offer electricity to large users, such as this facility, at a price of about 8 cents per kWh, including both supply and distribution.[5] This *below-market* price is made possible due to long-term supply contracts and ownership of various generation assets. In addition to this price, the municipal-owned utility is able to offer a 10% prompt payment discount and a 10% economic development discount, a local-interest subsidy (provided at local ratepayer expense).[6]

Recent Electricity Market Initiatives

With the Green Communities Act, the Global Warming Solutions Act, and the Green Jobs Act of 2008, the Governor and the General Court established a comprehensive energy market policy for the Commonwealth of Massachusetts. Like the Restructuring Act of 1997, which created a market framework to ensure economic efficiency and competition, the Green Communities Act updated that framework to give it a new and more explicit public purpose encompassing energy security, cleaner energy resources, and economic development resulting from the transition to a clean energy future for the Commonwealth. As a result, the initiatives mandated by or developed in response to these laws are best understood as pieces of a puzzle that fit together, rather than as a list of items that can be considered in isolation.

Energy Efficiency

Three-Year Plan

With the Green Communities Act, Massachusetts has embarked on a path toward significant energy efficiency improvements in homes and commercial buildings. The Act required that the electric and gas utilities pursue "all cost-effective energy efficiency," *i.e.,* eliminating energy waste whenever it is cheaper to do so than buying additional supply. While in the past utility-operated energy efficiency programs funded by fixed charges on electric bills were limited in size and had to turn people away, now every home and business in Massachusetts has been given the opportunity to participate in programs that save energy and money. Many other states are developing their own mechanisms to pursue all cost-effective energy efficiency.[7] Through implementation of this policy, the Commonwealth has adopted energy efficiency as its "first fuel" — what we look to first to meet demand before turning to new energy generation.

The electric (and natural gas) investor-owned utilities and Cape Light Compact (which provides such services on Cape Cod) pursue energy efficiency under the guidance of an Energy Efficency Advisory Council (EEAC), which represents a broad range of stakeholders and is under formal oversight by the DPU. After an extensive series of hearings and review of all relevant evidence and perspectives from various stakeholders in 2009, the DPU issued an "order" approving a Three-Year Plan for the years 2010 to 2012.

Decoupling

"Decoupling," or a decoupled rate structure, consists of removing the traditional link between the volume of electricity sold and revenues collected to run the distribution business. Decoupling is a significant complement to the Three-Year Plan for energy efficiency. While the costs of maintaining the distribution system remain relatively constant, the revenue to cover these costs is collected from customers according to the amount of electricity they use. As electricity sales decline through energy efficiency, the costs of maintaining the distribution system have to be collected over a smaller volume of electricity. Decoupling clears the way for greater energy efficiency by eliminating the disincentive for electric distribution companies to reduce the volume of electricity sales that exists under a traditional rate structure. Decoupling imposes no incremental cost on consumers or shareholders, with consumers continuing to pay for the system that delivers reliable electricity supply. Customers will see no change in their overall bills — unless they avail themselves of opportunities to improve their energy efficiency, in which case their bills will go *down*. Decoupling has been successfully implemented in many states across the country for electricity, and natural gas and water.[8]

Under the DPU's decoupling order, to achieve full decoupling, each electric and natural gas utility company must submit a rate case to the department and proceed through a full evidentiary hearing process, in order to establish rates. Rates will be set at a level designed to recover the company's prudently incurred costs, and subject to review and reconciliation on an annual basis. If a company's revenues are higher than expected, the excess is returned to consumers as a credit; if revenues are lower, due to demand-reduction programs and other factors, the company will be allowed to recover the difference through a rate adjustment. Utilities are required to file decoupled rate plans with the department as existing rate plans expire — by 2012 for most companies, though companies can file sooner on a voluntary basis.

Level Playing Field for Customer-Side Resources

In addition to pursuing energy efficiency whenever cheaper than supply under the Green Communities Act, the Administration has pushed aggressively with the grid operator ISO New England and with the Federal Energy Regulatory Commission (FERC) for a level playing field between demand-side (i.e., customer demand) and supply-side resources , to provide the lowest costs for ratepayers. For example, "demand-response" reflects the ability of retail electricity customers to *respond* to stress in the electricity grid by reducing *demand*. This might include, for instance, the ability of a store chain to turn down lighting and air-conditioning slightly during a hot summer weekday when the electric grid is stretched to peak capacity. For grid operators, demand-response resources serve a purpose similar to that of the power plants they dispatch during times of peak usage. (It is useful to note that so-called "peaking plants" called upon to meet peak demand are typically the most expensive to operate.) Historically, demand-side and supply-side resources have not been treated equally. The Administration has been pushing for the appropriate treatment of demand-response in the capacity and energy markets operated by ISO New England and in the FERC proceeding on price-responsive demand.

Renewable and Alternative Energy

The Green Communities Act set an aggressive target for how much of our electricity comes from renewable and alternative energy sources, using "portfolio standards." A portfolio standard requires retail sellers of electricity — both distribution companies and competitive suppliers — to buy a minimum and increasing percentage of the electricity they sell to customers from cleaner energy technologies that deliver electricity into the New England grid. The Green Communities Act changed the growth rate of the Renewable Energy Portfolio Standard (RPS), originally created in 1997, from one-half to 1 percent and created Portfolio Standards for additional technologies. Twenty-four states and the District of Columbia currently have an RPS.[9]

All retail sellers - competitive electricity suppliers as well as utilities (for their utility basic service supply providers) - meet this commitment by buying credits from the electricity generation sources. This accounting mechanism ensures that every unit of eligible electricity generated is counted exactly once and provides a price premium to power generation sources that may not yet be price competitive with fossil fuels. There are a number of eligible classes based on the technology and the in-service date. "Class I" are post-1997 renewable plants including wind, solar, small hydro, and eligible biomass and anaerobic digestion. "Class II Renewable Energy" are pre-1998 renewable plants that would not continue operating were it not for the standard. "Class II Waste Energy" are pre-1998 Massachusetts waste-to-energy plants.[10] The size of the Massachusetts RPS target is well within the mainstream among states. Among the 30 states that have an RPS, the Massachusetts RPS is *eighth* in the percentage target of its total RPS[11] as shown in Figure 5.

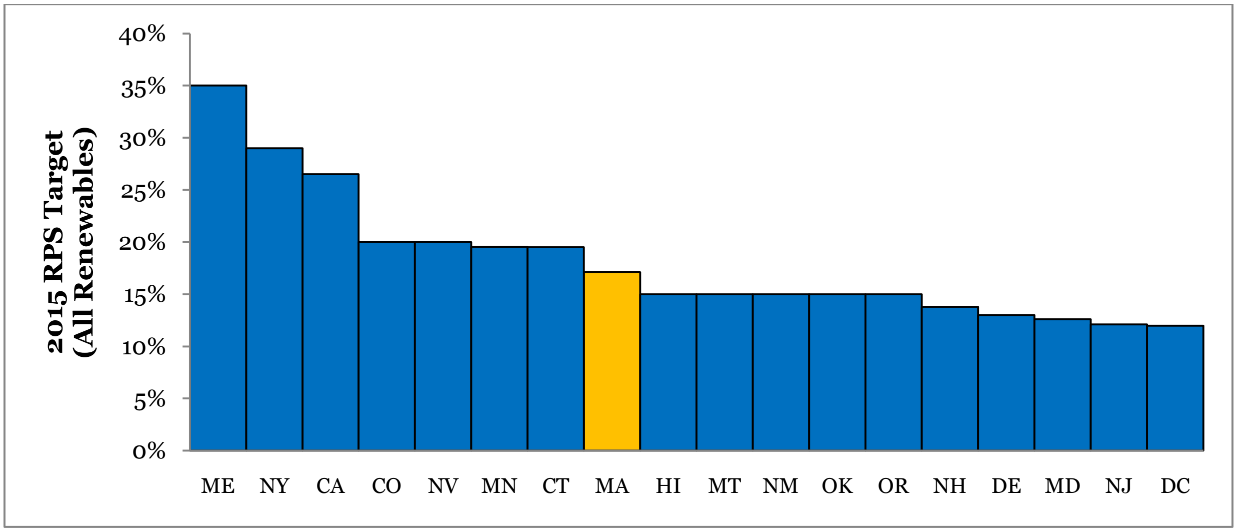


Figure 5 — 2015 State RPS Requirements (Total Percentage)
Source: http://www.dsireusa.org

Among those same 30 states, Massachusetts is *14th* in the percentage target for new renewable energy.[12]

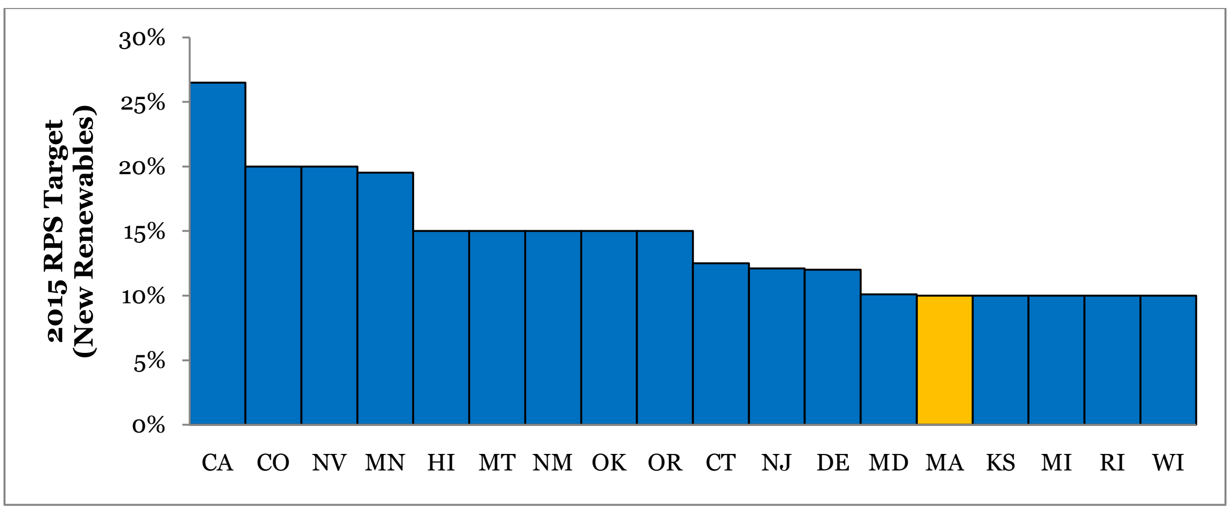


Figure 6 — 2015 State RPS Requirements (New Renewable Energy Only)
Source: http://www.dsireusa.org

The Alternative Energy Portfolio Standard (APS) includes primarily combined heat and power and a number of other technologies, such as flywheel storage, paper-derived fuel cubes, coal gasification with permanent carbon sequestration, and energy efficient steam technology. The APS is an innovative initiative that has received national recognition and has enabled a number of large businesses to substantially reduce their energy costs by installing combined heat and power units at their sites.

Clean Energy Imports

Canadian Large-Hydro Imports

In addition to deploying newer technologies in Massachusetts and the region, the Administration has pursued inexpensive clean energy resources elsewhere that could bring down electricity costs in New England in the long run. Such resources will be important for meeting the requirements of the Global

Warming Solutions Act, under which the Secretary of Energy and Environmental Affairs has determined that greenhouse gas emissions in Massachusetts must be reduced 25 percent from 1990 levels by 2020.

The eastern provinces of Canada have substantial hydro resources and are pursuing electricity exports to New England for their economic development. Canadian hydro imports have grown over the last 10 years, now accounting for 8.5 percent of New England's electricity consumption. However, transmission lines that deliver this resource to southern New England are at full capacity, preventing any additional Canadian hydro from getting to our market.

While initial inquiries regarding development of new transmission lines suggested the need for subsidies\ from New England states — either in the form of making large hydro eligible for the RPS or cost recovery for transmission from ratepayers — the Patrick-Murray Administration strongly encouraged the relevant parties to find a solution that avoided inappropriate subsidies for a *mature* technology such as large-hydro or for transmission lines that are appropriately paid for by the power plant developer. As a result, the Northern Pass transmission line is being developed by two Massachusetts utilities, Northeast Utilities and NSTAR, in partnership with Hydro Quebec (HQ), and with the support of the Administration. The power line would be funded completely by Hydro Quebec and costs will be recovered through sales of electricity at market prices in New England. This project would bring to New England enough inexpensive clean electricity to serve one million homes. The Patrick-Murray Administration continues to encourage additional transmission lines that do not require ratepayer funding.

Innovation and Sector Development

The Green Communities Act, in addition to setting ambitious nation-leading targets for energy efficiency and renewable energy policies shared by other states, also included several policy innovations specifically designed to establish the state as a national and global center of the clean energy industry.

While Massachusetts does not have the coal resources to compete with a state like Utah on electricity prices, it does compete successfully with the Leading Technology States in the innovation economy — and the innovation economy increasingly encompasses clean energy. These states are California, Connecticut, Illinois, Maryland, Minnesota, New Jersey, New York, Pennsylvania, and Virginia.[13] Specifically in the clean energy sector, a study in 2010 by market research firm Clean Edge, Inc. found that Massachusetts had, over the last four years, become one of the top three states for clean energy innovation, investment, employment, and policy in the nation. [14] Of the top 10 states in the Clean Edge report, six (including Massachusetts) were also Leading Technology States. These are the states we are competing with, and competing successfully, to be the driver of the clean energy economy.

To this end, the Commonwealth has used policies, programs, and specific provisions of the Green Communities Act and other recent laws to maximize activity in certain areas of clean energy development and deployment which offer the Commonwealth economic opportunities.

Solar

Solar energy has long been recognized as one of the largest, most readily available renewable energy resources.

> *"I'd put my money on solar energy...I hope we don't have to wait till oil and coal run out before we tackle that."*
> *Thomas Edison, in conversation with Henry Ford and Harvey Firestone, March 1931*

Solar has the potential to be ubiquitous — installed on every unshaded rooftop, on capped landfills, and other locations that are exposed to the sun. While solar photovoltaic technology is not cost competitive today with renewable energy technologies like wind, the cost of solar has been falling quickly and has the potential to be a leading renewable generation technology within a few years. By making a modest investment to establish a local industry cutting across the solar power value chain, Massachusetts has the opportunity to be a leader in that growing market.

Commonwealth Solar, launched in 2008 and funded by $68 million of existing renewable energy funds, began that process by introducing a simple rebate program which, when combined with federal incentives, sharply reduced the cost of solar for commercial and residential consumers. CommSolar quickly added 27 MW to the 3.5 MW of solar statewide previously installed statewide, and quadrupled the number of firms engaged in solar installation — drawing to Massachusetts out-of-state operations such as Borrego Solar and Sun Run, feeding the growth of start-ups such as Nexamp of North Andover, and giving Massachusetts electrical contractors such as Broadway Electric a new line of business. The Massachusetts Clean Energy Center (MassCEC) institutionalized the rebate program for small installations going forward, with CommSolar II, and Massachusetts devoted a significant portion of energy-related federal Recovery Act funds to further stimulate solar growth.

As a result, Massachusetts is in the midst of a 30-fold increase in installed solar power compared with four years ago, with over 50 MW now installed and over 90 MW expected to be installed or in process by the end of 2011. As this dramatic expansion of solar power takes place, Massachusetts is becoming one of the top solar markets in the country. Unlike many states with solar incentive programs — especially those that subsidize only small installations, Massachusetts has seen the installed cost of solar come down as much as 30% for larger installations as a competitive industry has developed and capitalized on falling panel prices, allowing rebates to be reduced four times to date.

To sustain continued steady growth, the Green Communities Act authorized a distributed generation "carve-out" of the RPS, requiring DOER to promulgate regulations requiring electricity providers to include a small amount of solar power as part of meeting their overall RPS requirements. Regulations implementing the carve-out set the target at a fraction of 1 percent of electricity sales in 2010 and remaining below 1 percent through 2015. Similar to credits associated with other classes of renewable and alternative energy, the carve-out provides for a Solar Renewable Energy Credit (SREC) that ensures appropriate accounting and provides a price premium to provide financial support. Having learned lessons from other states that have gone down this path, Massachusetts' design of the solar credit market has several mechanisms to control cost. For example, the annual target for all future years is not set in advance, but rather determined by a formula that looks back at recent years to establish the appropriate growth rate, thus preventing credit prices from spiking due to an out of balance market. In addition, an annual auction is used to provide credit price certainty to investors, thus lowering their risk.

The Green Communities Act also authorized utility-ownership of solar and the associated recovery of costs. Since these projects are eligible for solar credits under new state regulations and project costs incurred at the outset can therefore be offset by avoided solar credit purchases in the future, the advent of utility-ownership of solar does not result in additional costs beyond the cost of SRECs.

Offshore Wind

The Green Communities Act required the Commonwealth's electric distribution utilities to seek proposals from renewable energy projects in the state and in the region for long-term contracts of 10 to 15 years in order to facilitate their financing and create jobs. Long-term power purchase agreements, or PPAs, have been recognized over the past few years as an important element needed for financing power plants of any kind, particularly in restructured electricity markets. Under this section of the law, National Grid entered into a power purchase agreement with the first offshore wind farm that will be built in North America, Cape Wind. That contract was reviewed and approved by the DPU.

Like solar, offshore wind is expected to develop into a major new industry, with the U.S. Department of Energy (DOE) projecting 43,000 clean energy jobs to be created nationally by 2020. DOE and the Department of the Interior are pursuing an offshore wind strategic plan to address obstacles to the development of offshore wind and drive down its cost by 60%, to 7 to 9 cents per kWh, by 2030.

Massachusetts has the opportunity to lead the nation on offshore wind — and capture "first mover" advantages as this new industry grows around the first offshore project. Activities located here for the first project that could serve the industry up and down the East Coast include engineering and research (utilizing the new DOE–backed Wind Technology Testing Center in Charlestown); port facilities (proposed for New Bedford) and other shore-side support services; fabrication of foundations, structural steel, and other supply-chain components; and even potentially the manufacturing of turbines.

The potential for economic benefits associated with offshore wind development is so great that there is intense competition among other Atlantic Coast states for second place. From Maine to Virginia, states are pushing their own offshore wind projects, often through special-purpose legislation and explicit state support. New Jersey, for instance, has created a dedicated Offshore Wind Portfolio Standard, requiring its utilities to purchase the output of 1,100 MW of offshore wind capacity interconnected to New Jersey.

Smart Grid

The Green Communities Act charged the distribution companies to undertake "smart grid" demonstration projects. Smart Grid refers to a set of innovations that use information and communication technologies to help utilities improve grid performance and customers improve energy efficiency. Such innovations are technology intensive, providing ways to bring information technology (in which Massachusetts is rich) to bear on energy management, but also critical for sending market signals through rate design. Time of use pricing, for instance, could give consumers a chance to save on electricity bills by shifting energy intensive activities (such as running washing machines and dishwashers) from times of peak load to low (i.e., from late afternoon to evening or nighttime) and reducing stress on the power grid at the same time. Ultimately, two-way communication via the grid could allow a consumer to turn up her/his home thermostat (or turn it down in the summer) remotely just as s/he leaves work, reducing energy waste during the day while providing a comfortable home by the time s/he reaches the front door. Such sophisticated energy management techniques are already the talk of the utility industry, but progress is slow and ripe for leadership from states like Massachusetts. Green Communities Act-mandated demonstration projects will be evaluated by the distribution companies and the DPU to inform future investments in the distribution system that could spur innovation and benefit consumers.

Community-Scale Wind and Solar

The Green Communities Act also expanded the rights of customers who install small or community-scale solar and wind projects to "net-meter," or sell to their distribution company the excess electricity they generate. In addition, the new net-metering rules require the meter to essentially "run backwards," providing retail prices rather than wholesale prices for the excess generation. Net-metering is facilitating the installation of local renewable energy projects across the Commonwealth by improving their economics. Indeed, interest in development of municipal renewable energy has proven so keen that the Legislature has since raised the net metering cap from 1 percent of a utility's peak load to 3 percent, with 2 percent reserved for public projects. The Legislature also broadened the eligibility of government projects beyond those owned by the public entity and located on public land to include privately-owned installations on public or private land, as long as the electricity generated is purchased by the public entity.

Clean Energy Center

Complementing the Green Communities Act, the Green Jobs Act of 2008 created the Massachusetts Clean Energy Center (MassCEC). In MassCEC, the Commonwealth now has a public entity entirely dedicated to accelerating job growth and economic development in the state's clean energy industry. MassCEC serves as a clearinghouse and support center for the clean energy sector, making direct investments in new and existing companies, providing assistance to enable companies to access capital and other vital resources for growth, and promoting training programs to build a strong clean energy workforce that capitalizes on the job opportunities created by a vital new industry. MassCEC now also manages the state's Renewable Energy Trust Fund, created in 1998 and transferred to MassCEC in 2009 by an Act Relative to Clean Energy. This puts clean energy development and deployment under a single entity.

Benefits and Costs

Methodology

The state's electricity market reforms have both benefits and costs for the Commonwealth's electricity customers, economy, and environment and public health. This report assembles and synthesizes the assessments of benefits and costs based on information from regulatory proceedings on each of the market reforms, with a focus on electric customer impacts. Each of these proceedings and the associated record involve myriad technical issues and hundreds of pages of evidence and input. The following discussion provides an accessible overview. This report utilized costs and benefit methodologies that have been quantified and scrutinized through formal proceedings.

The methodology for assessing electric customer benefits and costs is well-established, having been adjudicated in numerous DPU cases over many years. In the case of state-mandated programs, the primary *costs* are charges on utility bills directly or indirectly resulting from state mandates, while *benefits* include savings for customers from avoided electricity supply costs, avoided transmission and distribution costs, electricity price suppression, avoided non-electric fuel costs such as heating fuel, hedge value, and long-term prices, each of which is explained below:

- **Funding:** Electric customers fund reform initiatives through both the delivery and supply portions of their bills, through specified charges as well as prices for electricity generation.
- **Customer savings:** Energy efficiency reduces energy consumption and costs for the lifetime of the measures implemented, with savings accruing to the participating customer.
- **Avoided transmission and distribution costs:** Energy efficiency reduces future transmission and distribution costs by decreasing the load on the system and mitigating the need for future expansion, with savings for all customers.
- **Price suppression:** The addition of new resources, such as energy efficiency, renewable and alternative energy generation, and hydro imports, lowers the market price of electricity for all. While the change in market price from each additional resource is small, the sum of all new resources results in substantial savings for all customers. For energy efficiency, this is also known as demand-reduction induced price effect, or DRIPE.
- **Non-electric savings:** Energy efficiency projects funded through electric bill charges treat the entire building, providing savings for participating customers from non-electric fuels, such as heating.
- **Hedge value:** Both reduced energy usage and energy supply from renewable resources provide protection from the fossil-fuel price rollercoaster, but such protection is easier to quantify in retrospect than in prediction. If future prices of fossil fuels are volatile, the hedge provided by fixed-priced renewable energy can be substantial.
- **Long-term prices:** Renewable electricity generation, once built and fully depreciated, has low operating costs just like large hydro. While it is difficult to attribute a specific value, installed renewable energy capacity will accrue to Massachusetts customers once it is depreciated and continues to generate electricity at low cost.

In addition to customer impacts, recent electricity market reforms also have potential economic development impacts. In general, these impacts have only more recently been discussed in regulatory proceedings and do not have the same degree of consensus on methodology. As such, the impacts are discussed qualitatively with accurate quantification of the net benefits left to future study. The primary benefits are induced investment, spending, and employment and sector development and comparative advantage, while the primary cost is potential loss of economic activity as a result of incremental electricity price increases:

- **Induced investment and employment:** Each initiative stimulates investment in energy efficiency and renewable energy that *would not have occurred* absent the reform. These investments create direct jobs in local and regional projects, indirect jobs in the local and regional supply chain, and induced jobs from local and regional expenditures of saved dollars — the latter generally seen as having the greatest impact. Many of these energy dollars would have flowed out of the state, and in some cases out of the country, if spent on conventional energy sources not native to Massachusetts or New England.
- **Sector development and comparative advantage:** In addition to immediate employment impacts, investments can help establish a new sector in the region and create a comparative advantage relative to other locations, with benefits in long-term growth and competitiveness.
- **Lost economic activity:** While Massachusetts's reform initiatives induce new investments in clean energy, they draw funds that might have been spent in other ways in the local and regional economy. As such, a perfect analysis of overall economic impacts from our clean energy policies would net out economic activity, including jobs, which may have been lost. Given the complexity of isolating the effect of electricity reform initiatives from other costs of doing business in the state as well as the difficulty in isolating the impact of incremental increases in energy costs resulting from these initiatives and the background condition of high energy prices in Massachusetts and New England as a whole, assessing specific job losses and the net economic impacts that could be linked to these initiatives requires significant analysis beyond the scope of this report.

Finally, the electricity market reforms have substantial environment and public health benefits that have to be considered in any analysis:

- **Avoided pollution:** The reforms reduce pollution of various kinds, improving air quality and reducing climate impact. Improvements in air quality have benefits in better public health outcomes and reduced health care costs.

Energy Efficiency

The benefits and costs of energy efficiency have been analyzed in great detail by the Energy Efficiency Advisory Council and in proceedings at the DPU.[15] The results are captured in Figure 7a. The annual electric energy efficiency investment in the Three-Year Plan ramps up to $738 million by 2012. Lifetime benefits are $2.08 billion in 2010 present value terms, or 280% of the investment costs.

The benefits of energy efficiency accrue over the life of the investment, typically ten years. As with any investment, the stream of future benefits is "discounted" to 2010 present value terms, with the discount rate established by DPU order 08-50 to be the yield of the ten-year U.S. Treasury bond, averaged over the previous 12 months.

As shown in Figure 7b, of the various categories of benefits, the largest benefit is the cost savings from avoided supply of electricity and of non-electric heating fuels over the lifetime of the investment in the building. The avoided supply benefits account for approximately three-fourths of the total benefits. The remaining one-fourth of the benefits are the system-wide avoided transmission and distribution costs and the system-wide price suppression.

The avoided supply benefit depends on a forecast of electricity and fuel prices. A consensus forecast to support these programs is established in the bi-annual commissioned study, *Avoided Energy Supply Costs in New England*.[16] The level of investment from 2013 and beyond will be established in a future Three-Year Plan but is assumed for the purposes of this analysis to continue at the 2012 level.

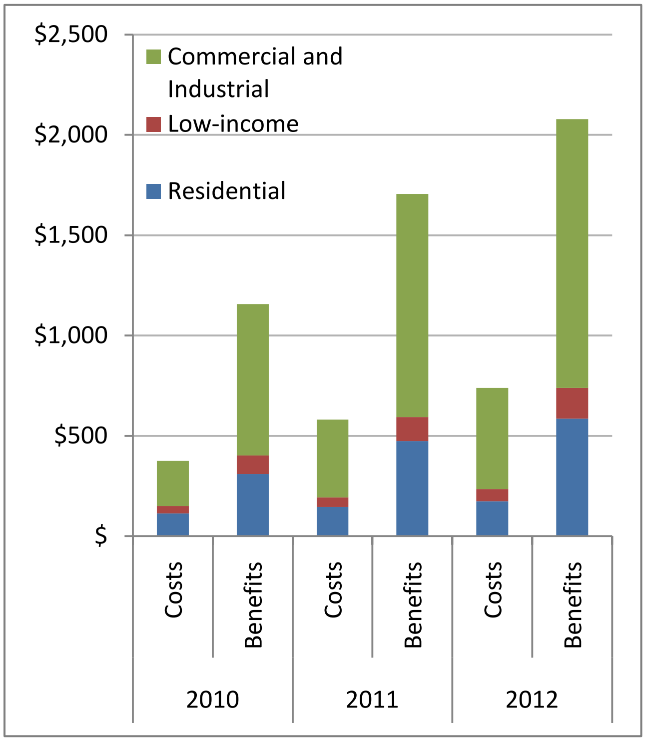


Figure 7a — Costs/Benefits of MA Energy Efficiency Initiatives (in millions)
Source: DOER/DPU

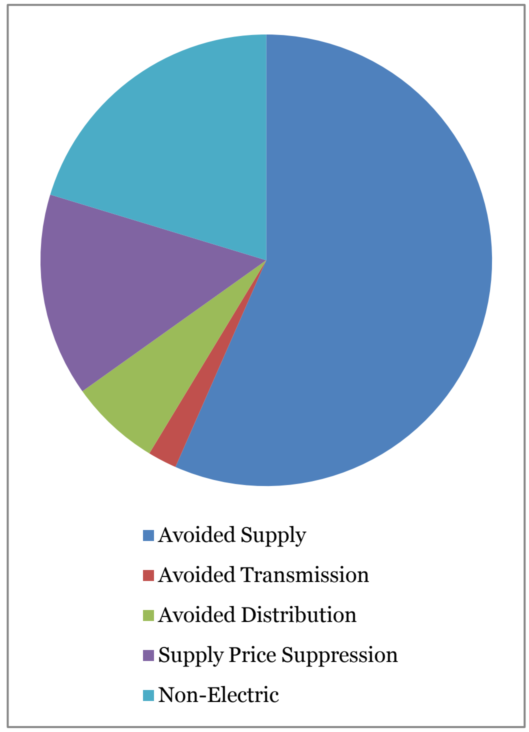


Figure 7b — Benefits of Energy Efficiency Initiatives
Source: DOER/DPU

Energy efficiency investments are funded through several sources:

- A System Benefits Charge (SBC) for energy efficiency of $0.0025 per kilowatt-hour was established in 1997 and remained the only source of funding until 2008. In utility bills, it appears as a separate line item.
- The Regional Greenhouse Gas Initiative (RGGI) auctions carbon allowances from ten states including Massachusetts, the proceeds from which are invested in energy efficiency. The RGGI charge does not appear separately, but is reflected in the rate presented in the supply services portion of the bill, since it is incorporated into the price of generation for fossil fuel plants.
- The Forward Capacity Market (FCM) provides payments to "capacity resources" including both power generators and energy efficiency and other "demand-side resources" for their value to the operation of the electric grid, which are reinvested in energy efficiency. *This is not an additional cost to electric customers*; if energy efficiency in Massachusetts did not provide these capacity resources and receive payments, the resources would have come from power generators.
- The participating home or building owner's cost-share, including outside financing from lenders and federal tax credits or grants, covers a portion of the energy efficiency project costs. This component does not affect other electric customers' rates. In fact, the greater this component is, the smaller the other funding sources can be and the lesser the impact energy efficiency investments have on rates for all electric customers.
- An Energy Efficiency Reconciliation Factor (EERF) makes up any shortfall between other funding sources and the investment plan for "all cost-effective energy efficiency" that costs less than additional supply. In utility bills, the EERF is reflected in distribution rates along with other distribution company investments.

Renewable and Alternative Energy

The primary economic benefit to electric customers of the renewable and alternative energy portfolio standards is price suppression from the addition of new resources to meet the standard or the continued operation of resources that would have otherwise been mothballed. In the Cape Wind contract proceeding, the DPU reviewed price suppression estimates provided by various parties. In this analysis, price suppression is assumed to be consistent with the DPU's and is assumed to grow in proportion (i.e. linearly) to the amount of electricity generated.[17]

The price suppression effect is in some ways counter-intuitive in that a resource with higher average costs can suppress prices (as long as the variable cost of the new resources is less than the variable cost of the last resource dispatched), albeit a tiny amount that becomes most significant when aggregated over all electric customers. The important point is that suppression of the electricity market clearing price is a result of adding additional supply that has low operating costs relative to the existing supply resources (as in wind resources which have no fuel costs), regardless of the nature of that supply. The amount of price suppression is determined by the electricity market's supply curve. For example, if a new super-efficient fossil fuel plant was built that had low operating costs, it too would result in price suppression. A renewable project, if it were economically viable to build, would have the exact same effect. The RPS provides renewable projects the additional revenue stream needed to be viable, in the form of renewable credits. The price of renewable credits is determined primarily by the capital costs of renewable projects relative to the electricity market clearing price. As such, the magnitude of the price suppression effect and the price of renewable credits are not related.

The primary cost to electric customers is the purchase of renewable and alternative energy credits by suppliers, and is estimated by the average market price for credits in any given year. Rather than make complex forecasts of credit prices, this analysis assumes a simple schedule for average credit prices consistent with publicly available data and projections.[18] With these assumptions, the costs and benefits are shown in Figure 8. In 2012, costs are estimated to be $111 million and benefits $328 million, or 296% of the costs.

In utility bills, the costs of complying with the renewable and alternative energy portfolio standards are reflected in the price for electricity *supply* services, provided by competitive suppliers or distribution companies for customers on basic service.

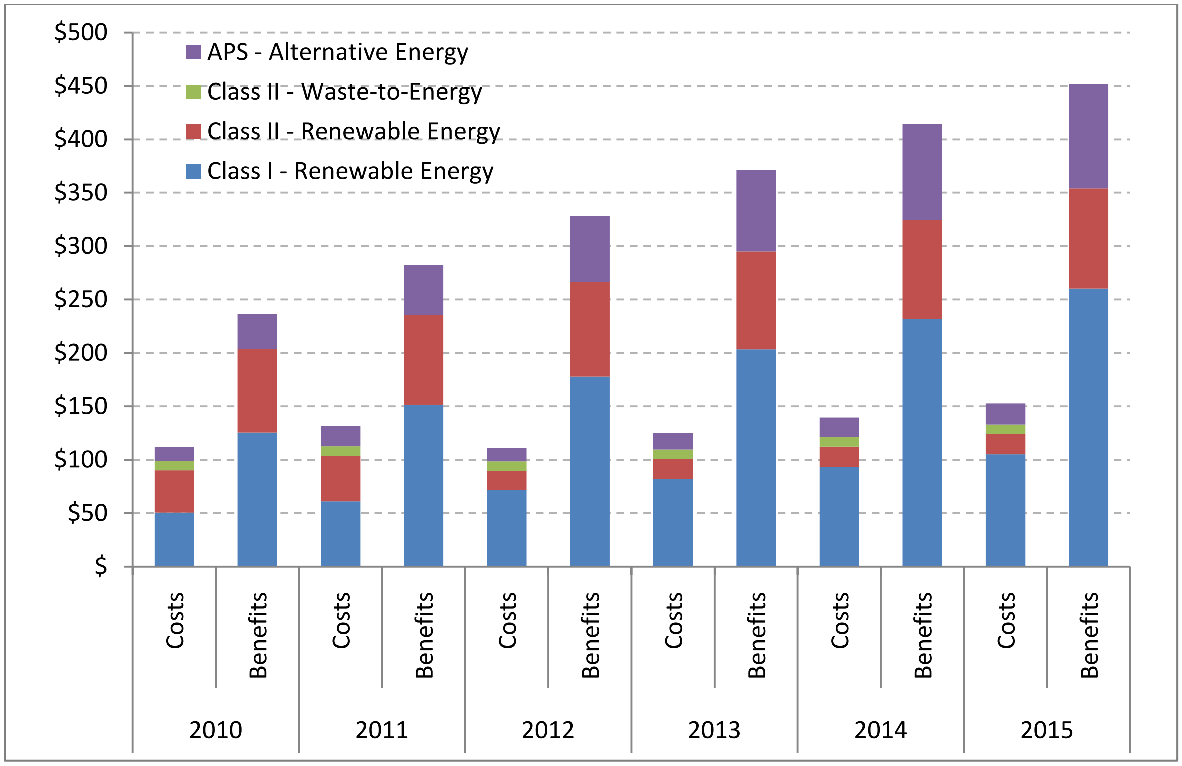


Figure 8 — Costs/Benefits of MA Renewable and Alternative Portfolio Standards (in millions)
Source: DOER

Clean Energy Imports

On imports and transmission planning, the stance taken by the Commonwealth has prevented inappropriate subsidies for technologies and entities that did not require them and has helped maintain a competitive marketplace. Projects moving forward, such as the 1200 MW Northern Pass project to import hydro power from Quebec, will not have any ratepayer costs and will offer the benefit of price suppression as with the addition of other new resources. While no regulatory proceedings have yet looked at this, a consultant's report for the project estimates $200 million to $300 million in savings to New England customers. Massachusetts customers make up about half of the New England electricity market.

In addition, the Administration's efforts to avoid central planning of transmission projects and allow the electricity market to function, driven by existing state renewable portfolio standards or a robust federal alternative, have saved Massachusetts ratepayers from shouldering billions of dollars in subsidies for energy projects developed in remote locations.

Innovation and Sector Development

There are five initiatives that support innovation and sector development. The first is the MassCEC, which houses the Massachusetts Renewable Energy Trust fund. A Systems Benefits Charge (SBC) for renewable energy was established in 1998 to provide funding to the Renewable Energy Trust Fund, and is paid by customers of investor-owned utilities in Massachusetts. The charge of $0.0005 per kilowatt-hour amounts to approximately $25 million per year and appears on a utility bill as a separate line item under delivery services. In November 2009, an Act Relative to Clean Energy transferred the state's Renewable Energy Trust Fund to the MassCEC to bring together all resources focused on catalyzing the state's clean energy cluster. Municipal light plants (MLP) can also opt in to the Renewable Energy Trust, and several have done so.

The Smart Grid demonstration projects required of each distribution company by the Green Communities Act were filed with the DPU for approval of projects and of a mechanism for recovering costs from distribution customers. The companies also applied to the DOE for federal grant funds to defray the cost of the projects. NSTAR's project and cost recovery was approved by the DPU. Half of the project costs will be funded by a federal grant for $7.5 million and the remaining $7.5 million will be funded through distribution rates over three years starting in 2011. National Grid has not been approved for cost recovery for its $56 million project over a five year period. In this analysis, it was assumed that National Grid's project will be approved and that cost recovery begins in 2011. In utility bills, these costs will be reflected in the respective company's distribution rates under delivery services.

Net-metering requires the distribution companies to pay community-scale solar and wind customers near-retail electricity prices for generation in excess of what is consumed on-site. The difference between these retail prices paid and the market value of that energy when the energy is sold can then be recovered through a Net-Metering Recovery Surcharge (NMRS) incorporated into distribution rates approved by the DPU. The amount of distributed generation capacity that can be net-metered is capped at 3% of peak capacity in each utility's service territory, or 330 MW statewide. The actual NMRS filed for recovery in 2011 for the year 2010 was approximately $1.6 million, with 40 MW of capacity installed. In this analysis, the surcharge is projected to grow in future years in direct proportion to the first year NMRS cost, with a three-fold increase by 2012, six-fold by 2013, and nine-fold by 2014 and beyond until the 3% cap is reached. At its peak, the net-metering surcharge is estimated to be $14 million. In utility bills, these costs will be reflected in the respective company's distribution rates under delivery services.

The Cape Wind contract with National Grid was analyzed in great detail by the DPU. The department's order lays out the costs and benefits for electric customers and the benefits for economic development and meeting environmental goals. The project is expected to begin operation in 2013 and the annual costs in 2013, 2014, and 2015 are estimated to be $49.8 million, $58.6 million, and $56.1 million respectively.[19] In utility bills, these costs will be reflected in the company's distribution rates under delivery services.

The DPU order also incorporates a number of associated outcomes which, while difficult to quantify, are nonetheless clear benefits to the Commonwealth. These include:

- downward price adjustments under certain conditions;
- the option to extend beyond 15 years at a "cost of service" pricing similar to that which many fully depreciated hydro facilities offer in other parts of the country; and
- employment and sector development.

The Class I – Solar Carve Out or Solar Credit (SREC) Program, builds on the success of the Commonwealth Solar rebate programs to establish and maintain the growth of a solar industry in Massachusetts. The costs of the program are determined by the annual target, which is governed by a formula and the average price of solar credits in a given year. As with the renewable and alternative standards, rather than make complex forecasts, this analysis assumes a simple schedule consistent with current market assessments.[20] In utility bills, these costs will be reflected in the supply services, provided by a competitive supplier or a distribution company for customers on basic service.

As with offshore wind, supporting a growing solar industry produces impacts which, while difficult to quantify, are clear benefits to the Commonwealth. It catalyzes a value chain of product sales and installation in the state and positions the Commonwealth to capitalize quickly as solar power comes down the cost curve. The federal government is making substantial investments in solar development leading to parity with grid electricity by 2015 as illustrated in Figure 9 below:

Market Sector	Current U.S. Market Price Range (¢/kWh)	Cost (¢/kWh) Benchmark 2005	Cost (¢/kWh) Target 2010	Cost (¢/kWh) Target 2015
Residential	5.8-16.7	23-32	13-18	8-10
Commercial	5.4-15.0	16-22	9-12	6-8
Utility	4.0-7.6	13-22	10-15	5-7

Figure 9 — Projected Future Costs of Installing Solar PV
Source: DOE

Figure 10 assembles the costs to electric customers of these innovation and sector development efforts. Innovation and sector development amounts to approximately 20% of the overall investment, or about $0.0037 than per kWh. The benefits *to electric customers* associated with these efforts are already reflected in the earlier categories and are not included here.

In terms of overall economic impact, any employment gains attributable to these efforts must be evaluated net of any potential employment losses in other industries due to higher electricity costs. As to employment gains, the early returns on these investments are favorable. Clean energy employment has grown 65 percent over the past four years, now totaling at least 11,000 jobs in Massachusetts, according to employer surveys conducted by the Massachusetts Clean Energy Center. As to potential employment losses, there are few existing studies that evaluate the net employment impact of clean energy growth policies in the United States or internationally. One recent report, conducted by the Universidad Rey Juan Carlos in Spain, found that the Spanish experience with renewable energy incentives resulted in a net negative employment impact. However, the Spanish subsidies for renewable generation, based on feed-in tariffs, were substantially higher than the surcharges that are imposed under Massachusetts electricity market reforms.[21] Therefore, the conclusion of that study, namely that excessive subsidies for renewable energy can lead to job losses that offset job gains, do not appear to be directly applicable to an analysis of the Massachusetts experience. Rather, the study suggests the need for ongoing data collection and analysis of employment gains and losses as the anticipated investment in these efforts grows over the next several years.

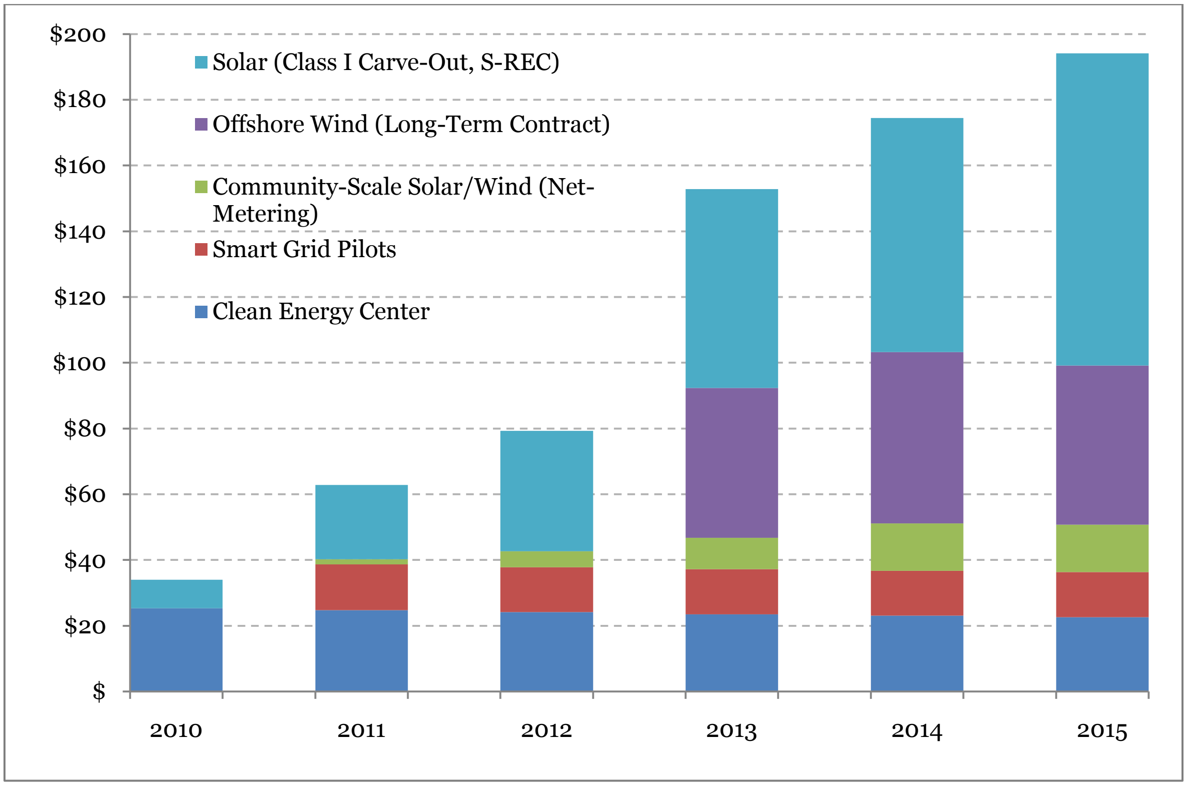


Figure 10 — Costs of Innovation and Sector Development Efforts (in millions)
Source: DOER/DPU

Renewable Energy Impact on Electric System Reliability

Wind Energy Integration

Electricity grids, power supply portfolios, and power markets are designed to efficiently deal with the variability of electric demand. In New England, this is particularly true due to the substantial role of flexible hydroelectric and natural-gas-fired generation, and hydroelectric pumped storage capacity. However, adding significant amounts of wind power to a region's electric grid can impose new demands on the system—often referred to as integration issues or challenges. These can include impacts on operations, scheduling, operating reserves, regulation, forecasting, dispatch, transmission, and emissions. While many of these impacts are often similar in nature to those imposed by load variations or unplanned outages, their impacts—particularly at high penetrations—can differ in magnitude and frequency. As a result, it is important to understand the potential impact of adding material amounts of wind power to the grid to anticipate and mitigate any undesirable impacts.

New England Wind Integration Study (NEWIS) released in December 2010 is intended to complement the results of a 2009 economic study ISO New England developed for the New England Governors[22]. The goal of NEWIS was to determine the operational, planning, and market impacts of integrating substantial wind generation resources into the New England Balancing Authority Area. The study was also designed to make recommendations for mitigating any negative impacts on the region's electricity system of increased wind integration. The economic study evaluated scenarios for up to 12,000 MW[23] of wind generation in New England and conceptual transmission to deliver wind energy to the region's load centers; it did not evaluate operational impacts. The New England States Committee on Electricity (NESCOE) used the technical analysis in the ISO's economic study as a basis for developing the New England Governors' Renewable Energy Blueprint, which, in turn, has led the states to explore options for regional coordinated procurement of cost-effective renewable resources.

The NEWIS results show[24] large scale wind integration, up to the 12,000 MW studied (or 24% of the region's energy supply), is feasible for operating in New England's electric grid. Specific findings include: (a) wind would likely displace oil-fired generation with natural gas units providing operating reserve, regulation and other ancillary services; (b) as wind penetration increases, operating reserve and regulation will need to increase; (c) market design changes may be needed to incent resources to provide greater operating flexibility; (d) accurate wind generation forecasting will be needed; and (e) favorable wind sites tend to be in remote areas of New England and would likely require transmission development.

Based on ISO-NE interconnection Queue January 2011 there are 3,300MW of renewable projects[25] proposed in New England. Most of these projects are wind – representing 2, 974 MW or 89% of the renewables proposed. Massachusetts utility scale wind projects represent 20% of this total. Considering the ISO-NE average interconnection processing time is about 500 days and ranges from 100- 800 days[26] it may take up to five years before a resource is operational.

Based on industry studies, it is our conclusion the region's electric grid can *readily* accommodate 12,000 MW of wind and the region is many years from approaching this capacity. Further, it's important to note that system reliability is ensured through the ISO-NE interconnection standards.

Solar PV Integration

In New England, the installation of solar PV is increasing rapidly with Massachusetts accounting for the large portion of this growth. PV capacity grew from 21.4 MW cumulative in 2008 to 40.7 MW in 2009, and will likely exceed 100 MW in 2012. Although solar capacity on the ISO-NE grid will most likely be far less than wind capacity, as reported by NERC[27], PV has demonstrated a potential for much more rapid changes in output than wind. ISO-NE has indicated as installed solar capacity grows impact on system operability will need to be examined but no near term impacts are anticipated. With its significant output on summer days, PV provides output often coincident with demand peaks and thereby contributes to system reliability benefits. DOER and DPU are actively engaged with these topics and will continue to monitor ISO-NE and other research on these issues.

Overall Benefits and Costs

The recent electricity reforms made up of these four distinct categories of initiatives are most appropriately evaluated as a portfolio. Each category carries some costs and provides some benefits, with some greater in the former and others in the latter. But the *kinds* of costs and benefits vary as well. For instance, energy efficiency investments produce cost savings which, besides benefiting participating customers, fuel the broader existing economy, while sector development puts Massachusetts on the cutting edge of technology where the Bay State generally capitalizes on competitive advantage relative to other states. It might be possible to choose one category of clean energy initiative to the exclusion of others, capturing only the benefits associated with that category, but, as a strategy to maximize Massachusetts' advantages in the transition to a clean energy economy, the four together are more powerful than any one.

Figure 11 shows the overall benefits and costs to electric customers, recognizing that some benefits and costs are difficult to quantify and others accrue to the Commonwealth as a whole rather than to customers. At $2.5 billion, the benefits expected to accrue to electric customers are nearly two and half times greater than $1.1 billion cost of implementing these initiatives — representing a prudent investment for ratepayers and the Commonwealth. In terms of utility bills, the lifetime benefits of each year's program activities can also be described as $0.028 per kWh for 2010, increasing to $0.048 for 2015, while the costs are well less than half of those amounts — $0.010 per kWh for 2010 and $0.021 for 2015.

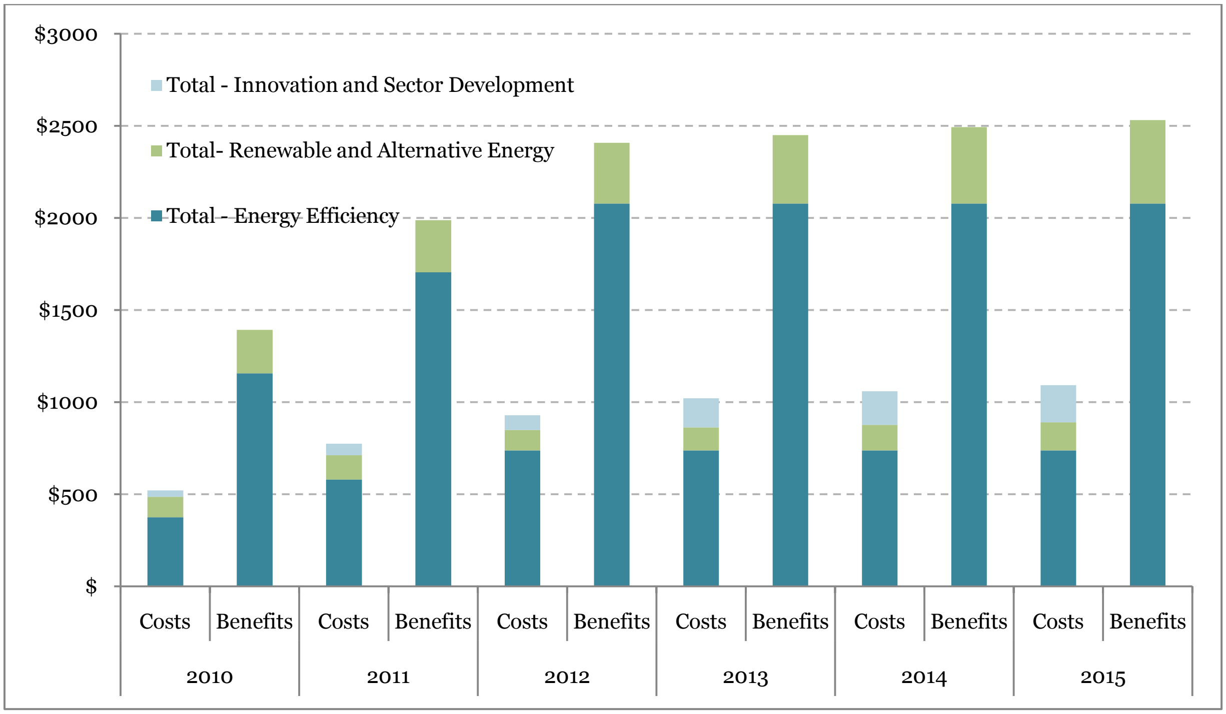


Figure 11 — Overall Costs/Benefits of MA Electricity Initiatives (in millions)
Source: DOER/DPU

Conclusion

For decades, Massachusetts (like its New England neighbors) has been a high energy cost state. With no indigenous fossil fuel and no large-scale hydro, Massachusetts is particularly vulnerable to the wide price swings typical of global energy commodity markets. As can be seen by the three-fold increase in electricity supply prices in the 1998-2008 period, followed by a substantial drop in the past two years, international market forces swamp state-level public policies in determining energy costs for Massachusetts businesses and residents.

While true for decades, this exposure to market forces has become more transparent since the 1997 Restructuring Act, as divestiture of power generation by utilities and creation of a competitive regional wholesale power market shifted risk for large-scale capital investments from ratepayers to the private market. The result has been a massive upgrade of generating capacity in cleaner, more efficient power plants, all privately financed, along with new opportunities for large commercial, industrial, and institutional customers to benefit from competition between electricity suppliers. But for basic-service customers, electricity prices now track the ups and downs of the global energy marketplace more closely than ever before.

It is in this context — the fundamental vulnerability Massachusetts faces in relying on fossil fuels — that recent energy reforms have put the Commonwealth on a course to a clean energy future. Under the Green Communities Act, the Global Warming Solutions Act, and numerous administrative and regulatory actions in line with them, the Commonwealth has begun to pursue a comprehensive energy policy to make Massachusetts more energy efficient, less dependent on imported fossil fuels, and a national leader in the development and deployment of clean energy technologies. By facilitating economical energy efficiency upgrades, creating market demand for new renewable energy generation, pursuing appropriately financed hydro power imports, and resisting proposals to subsidize generation in remote U.S. locations, this comprehensive strategy promises ratepayers benefits in reduced energy usage, avoided transmission costs, and lower wholesale market prices. This strategy also includes an economic development component, as it provides support to the creation of solar power and offshore wind industries where Massachusetts has opportunities to establish competitive advantage as a state.

In contrast to an estimated $8.46 billion spent on electricity in Massachusetts in 2010 (and over $9 billion in 2008 when natural gas prices were at their recent peak), the resources committed to this strategy are modest, and nearly all of them promise direct benefits to ratepayers in addition to the Commonwealth as a whole. The biggest investment by far is in energy efficiency — annual spending reaching $738 million in 2012, which will produce $2 billion in savings for ratepayers over the lifetime of the measures installed. It is notable that the vast bulk of the savings from these investments will accrue to commercial and industrial customers, because these are where the biggest savings can be found.

Renewable and alternative energy will likewise provide ratepayer benefits outweighing the added cost of incentives for these resources resulting from wholesale market price reductions due to introduction of additional generation. At $328 million, the ratepayer benefits are projected to be three times the $111 million cost of implementing these renewable and alternative energy initiatives. Clean energy imports will likewise add low emissions electricity to New England's supply mix, while Massachusetts resists transmission mandates that would saddle customers here with undue costs. Even solar and offshore wind development — those initiatives that require the highest costs in the short run – help Massachusetts take the lead in markets for renewable energy resources critical to the nation.

Appendix: Chapter 240, An Act Relative to Economic Development Reorganization

SECTION 185. Notwithstanding any general or special law to the contrary, the executive office of housing and economic development, in consultation with the executive office of energy and environmental affairs, shall conduct a study on the costs and benefits of recent electricity market reforms. The study shall include, but not be limited to:

i. an analysis of the economic and reliability implications of implementing administrative, regulatory and legislative mandates as they pertain to electricity;
ii. the extent to which these mandates impact the rates paid by residential, commercial and industrial customers in the commonwealth and contribute to the bill savings realized by these customers; and
iii. the extent to which these mandates contribute to economic development in the state.

The study shall be completed with stakeholder input, including representatives from various sectors of the commonwealth's economy. The study shall be completed and submitted to the joint committee on telecommunications, utilities and energy and the joint committee on economic development and emerging technologies no later than December 31, 2010. [28]

Notes:

[1] http://econ-www.mit.edu/files/1184
[2] http://www.elistore.org/Data/products/d19_07.pdf
[3] www.nap.edu/catalog.php?record_id=12794
[4] http://www.mass.gov/Eoeea/docs/doer/publications/doer-municipal-utility-rpt.pdf
[5] http://www.hged.com/177e.pdf
[6] http://www.hged.com/html/incentive_programs.html
[7] http://www.aceee.org/files/pdf/ACEEE-2010-Scorecard-Executive-Summary.pdf
[8] Appendix D in http://www.raponline.org/Pubs/MN-RAP_Decoupling_Rpt_6-2008.pdf
[9] http://apps1.eere.energy.gov/states/maps/renewable_portfolio_states.cfm
[10] http://www.mass.gov/Eoeea/docs/doer/rps/rps+aps-2009annual-rpt.pdf
[11] http://www.dsireusa.org/summarytables/rrpre.cfm. California's target for 2015 is taken to be the average of its 20% target in 2010 and 33% target in 2020.
[12] http://www.dsireusa.org/summarytables/rrpre.cfm. California's target for 2015 is taken to be the average of its 20% target in 2010 and 33% target in 2020.
[13] http://www.masstech.org/institute2009/the_index_2009.html
[14] http://www.cleanedge.com/reports/pdf/MassCEC2010.pdf
[15] http://www.ma-eeac.org/docs/DPU-filing/1-28-10%20DPU%20Order%20Electric%20PAs.pdf . Benefits and costs appear on pages 176-178.
[16] http://www.synapse-energy.com/Downloads/SynapseReport.2009-10.AESC.AESC-Study-2009.09-020.pdf
[17] Based on DPU 10-54 Revised RR-DPU-NG-4, it is estimated that Massachusetts electric customers *in total* benefit by approximately $50 *per year* per additional megawatt-hour of renewable generation in that year.
[18] The assumed credit prices are Class I — $20, Class II — $25 in 2010-2011 and $10 thereafter, Class II WTE — $5, APS — $20 in 2010-2011 and $10 thereafter. The annual compliance targets and the annual retail sales subject to compliance for 2010-2015 are as assumed in the *2009 Annual RPS & APS Compliance Report*. Costs attributed to Class I include compliance met with the solar carve-out, with only incremental costs being attributed to the carve-out. (http://www.mass.gov/Eoeea/docs/doer/rps/RPS%20and%20APS%202009%20Annual%20Compliance%20Report%20DOER%20111710%20rev%20011111.pdf). For the new classes--Class II, Class II WTE, and APS--the share of sales that are estimated to be "non-exempt" from compliance for 2010, 2011, and 2011 are 86.7%, 92.5%, and 97.2% respectively.
[19] DPU 10-54 Order citing ESAI Monthly Pricing forecast column from MNM-2 Supplemental. As a project-specific analysis, the Order includes price-suppression benefits in its accounting. In this analysis, price suppression benefits are represented in the accounting for the RPS overall and so are not included here.
[20] The target is assumed to require 20% growth in new solar installations each year. Credit prices are assumed to be $400 in 2010-211, $350 in 2012-2013, and $300 in 2014-2015. Non-exempt sales are 63.0%, 80.0%, and 90.0% in 2010, 2011, and 2012 respectively. Costs attributed to this program are *incremental* to the costs if there were no carve-out.

[21] http://www.juandemariana.org/pdf/090327-employment-public-aid-renewable.pdf, "Study of the effects on employment of public aid to renewable energy sources," Research Director Gabriel Calzada Alvarez PhD, Instituto Juan De Mariana, Universidad Rey Juan Carlos, March 2009.
[22] 2030 Power System Study: Scenario Analysis of Renewable Resource Development, Report to the New England Governors, ISO New England, February 2010.
[23] The economic study screened out potential wind development in certain geographic locations (e.g., in areas with high elevation or slope or in proximity to urban areas) where development was considered infeasible for technical or other reasons. For example, the study assumes a five mile buffer around the Appalachian Trail (in each of the affected states) and around the Long Trail (in Vermont), which precludes potential inland wind development in areas with some of the best wind regimes (i.e., higher wind speeds).
[24] Technical Requirements for Wind Generation Interconnection and Integration, NEWIS Task II Report, 2009.
[25] ISO-NE variable technologies June 29, 2011 PAC Meeting
[26] ISO-NE Briefing to Maine Joint Energy, Utilities & Technology Committee, January 20, 2011
[27] NERC's special report, "Accommodating High Levels of Variable Generation," published April 16, 2009
[28] http://www.malegislature.gov/Laws/SessionLaws/Acts/2010/Chapter240