A Guide to Electricity Markets, Systems, and Policy in Massachusetts

A Boston Green Ribbon Commission Report

Prepared by Conservation Law Foundation (CLF)
on behalf of the Boston Green Ribbon Commission
SEPTEMBER 2015

BOSTON Green Ribbon COMMISSION

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TABLE OF CONTENTS

INTRODUCTION

The purpose of this guide is to help stakeholders in the City of Boston understand how regional electricity markets function in New England and Massachusetts, and to introduce some of the important choices about the design of those markets currently being discussed in the region.

The guide was prepared by the Conservation Law Foundation for the Boston Green Ribbon Commission, a network of business and civic leaders supporting the implementation of the City of Boston's Climate Action Plan (CAP). It is one of three information products commissioned by the GRC. The other two focus on: 1) an overview of how regional electricity and gas infrastructure decisions are made in New England, and 2) an overview of options for large scale institutional renewable energy purchasing.[1]

The Boston Climate Action Plan has set aggressive goals for greenhouse gas (GHG) emission reductions for the City—25% by 2020 and 80% by 2050. For the first four years of its operation (November 2010—November 2014), the GRC's work in support of the climate mitigation goals of the City of Boston's Climate Action Plan (CAP) has focused primarily on energy demand issues—more specifically, reducing energy consumption and related GHG emissions in the large building and institutional sector (also known as the Commercial/Industrial or C/I sector), and more recently, on reducing transportation-related emissions.

Electricity and natural gas demand is, however, only half of the energy system equation. The other half is energy supply—where the energy comes from (generation of electricity and extraction of natural gas) and how it gets delivered to customer end-use points (transmission, pipelines and distribution). It is clear that there are a number of important choices that stakeholders will be making over the next decade affecting energy supply and distribution. It is important for GRC stakeholders to understand the state's and region's energy supply situation, what the choices are, how they will affect their energy plans, and the ability of the City to achieve its CAP goals.

The electricity and natural gas supply "ecosystem" in Boston, Massachusetts, and New England is complicated and dynamic, and involves a myriad of issues, initiatives, and regulatory decision-making processes and procedures. A complex mix of players is involved, including the Federal Energy Regulatory Commission (FERC), ISO-New England, the Department of Public Utilities, regional electricity and natural gas utilities, and energy suppliers from outside the region.

The Green Ribbon Commission requested this study because an overview of regional electricity markets would be useful to its members and the many other stakeholders impacted by these issues, but who are not already deeply involved in them. This guide is designed to serve that purpose. Support for this report is provided by the Boston-based Barr Foundation as part of its climate program and efforts to advance clean energy in the region.

[1] All three of these reports are available for downloading from the "Materials" page on the Green Ribbon Commission web site.

CHAPTER 1

Deregulation

Background: Utilities, Regulation, Deregulation, and the Electricity Bill

WHAT IS A UTILITY?

A "utility" is a special type of business that operates in an field in which a "natural monopoly" exists. The utility business model is the way society and the law attempt to address (and mitigate the effects of) this natural monopoly.

Most businesses in the United States are governed by free enterprise. That is, most businesses are allowed to set their own prices and compete with one another freely. For example, if a person owns a Chevrolet dealership, she can set her prices as high or as low as she wishes. A Chevy dealer, for example, might say, "I am going to set my prices very high in order to try to make a lot of money." Or, she may say, "I am going to set my prices very low, and try to make up in increased volume what I am not making on individual sales." In either event, the choice belongs to the business owner; and most business owners must compete with others in the same business.

Utilities are different. Utilities come about because of what are called "natural monopolies." It would be unwise and economically inefficient for society to have more than one water company dig up our streets and put in a whole system of pipes to (separately) bring fresh water to every household in a city. Likewise, it would be unwise and economically inefficient to have more than one gas company dig up our streets and put in a whole system of pipes to (separately) bring natural gas to every household in the city. The same is true for electricity. The businesses that sell these commodities are "natural monopolies."

Our society makes a two-part bargain with these natural monopolies. On the one hand, society makes an exception to the general no-monopoly rule that is the familiar pattern for nearly all other businesses. With utilities, we recognize the "natural monopoly" (because we do not want to have three water companies all tearing up the roads to install competing sets of pipes) and we allow the utility to maintain its monopoly. On the other hand, society limits how much these monopolies are permitted to charge. Utilities are closely regulated by Public Utility Commissions (PUCs); these PUCs tell utilities how much they are allowed to charge and exactly how much profit they are allowed to make. Other businesses are not subject to the same degree of regulation.[2]

REGULATION AND DEREGULATION

In the early days of electricity, most electricity utilities were "vertically integrated." This meant that every geographical area in the country had only one electricity utility, and that utility fulfilled all three roles in the electricity grid:

- **Generation**—Owning the power plants that burned coal, natural gas, oil, or some other fuel to make electricity;
- **Transmission**—Owning and operating the high voltage (often 500-, 345- or 230-kilovolt) lines that did the long-distance transmission of electricity from where it was made to where it was used; and
- **Distribution**—Owning and operating the lower voltage (usually 120- or 240-volt) lines and local transformers responsible for actually distributing electricity to end-use customers (like individual homes or businesses).

[2] Note that the names of these utilities commissions can vary slightly from state to state. Rhode Island and Maine have Public Utilities Commissions (PUCs); Massachusetts has the Department of Public Utilities (DPU); Connecticut has the Public Utilities Regulatory Agency (PURA). Despite these different names, these agencies all have substantially similar roles and functions.

Starting in the 1990s, many states, including the New England states, passed laws that broke up these three separate functions and gave these separate functions to different companies. This process was called "deregulation." In this context, this is what was meant by deregulation: distribution utilities were legally obligated to divest themselves of their generation assets. Those electricity generating power plants were sold to multiple, private, non-utility companies in New England that compete against one another to sell their electricity onto the grid. The idea, or theory, behind deregulation was that competition in markets (including in electricity markets) is a good thing, and that competition could and would ultimately lower electricity rates for customers.

Today, as a result of deregulation, what most people think of as their "electricity utility" (such as National Grid or Eversource) is really just a "transmission and distribution" company (T&D). The T&D utility performs the last two functions described above and owns the large transmission lines that are found in utility rights of way as well as the wires and poles in your neighborhood that bring the electricity to your home.

As we will discuss in greater detail in Chapter 3 , Independent System Operators (ISOs) have been created in recent years to design and operate the wholesale markets in this world of deregulated utilities.

THE ELECTRICITY BILL

In our current, deregulated utility world, the bills that electricity customers receive from their utilities are divided into several different line items. The two main parts of the bill are the commodity portion and the transmission and distribution portion.

The commodity portion—For most electricity utilities and most electricity customers, the commodity portion of the bill is about two thirds of the electricity bill. (When discussing electricity utilities, the commodity that we are discussing is electricity; for gas utilities, the commodity is natural gas.) T&D utilities (like National Grid or Eversource) do not make or lose any money on the commodity portion of the electricity bill. This is a pure pass-through. T&D utilities buy electricity in the wholesale markets run by the ISO (see Chapter 3); these T&D utilities then pass their cost for that commodity—whatever that cost is—along to customers. Over the course of a year, the T&D utility makes zero dollars (and loses zero dollars) on the commodity portion of its customers' bills.

Utility commissions may raise or lower the commodity cost to customers several times a year to ensure that the T&D utility ends up neither making nor losing money on the commodity portion of the bill over a period of time. It is important to understand that these rate pass-throughs are required by law. Utility commissions have no discretion about passing along (to customers) the commodity costs paid by utilities for this commodity (electricity), but utilities also make no profit on this commodity.

So how do utilities make money?

The transmission and distribution portion—Utilities make money by charging for transmission and distribution. The remaining portion (that is, non-commodity portion) of customers' bills (amounting to about one third) is the transmission and distribution portion of the bill; that is, the portion of the bill related to the local, intra-state and inter-state transmission of electricity. Unlike the commodity portion of the electricity bill (which is a pure pass-through), the amount of money that regulated utilities are allowed to charge on the transmission and distribution portion of the bill is controlled by utility commissions and the Federal Energy Regulatory Commission (FERC). PUCs can adjust distribution rates upward or downward in a regulatory proceeding called a "rate case." In theory, a utility should be able to cover two different types of costs through the transmission and distribution portion of a bill. First, a utility covers all of its operating costs through the distribution charges. For an electricity utility, this means the cost of maintaining the actual electricity grid (including all the wires, transformers, and substations), the cost of staff salaries, operating its buildings, running its billing system, and so forth. Second, a utility makes its profit on the transmission and distribution side of a bill.

UTILITY PROFIT: ROE

The profit that a utility is allowed to earn is defined by the technical term "Return on Equity" (ROE). The equity that a utility has is the dollar value of its physical assets. For an electricity utility, that is the value of its wires, transformers, substations, and so forth. For a gas utility, that is the value of its pipes, compressors, and so forth.

In a utility rate case, the PUC sets the level of Return on Equity that the utility is allowed to earn (until the next rate case is conducted). Utility ROEs commonly run between about 8% and about 12%. If an electricity utility is allowed an ROE of 8% by the local PUC, you add up the total value of the distribution utility's wires, transformers, substations, and physical plant; then multiply that amount by 8%; and the product of that multiplication is the ROE (profit) that that utility is permitted. Similarly, FERC approves ROEs for T&D investments associated with interstate transmission lines. This ROE or profit is designed to motivate the utility to invest in infrastructure improvements and to inspire investors to invest in the utility.

Utility commission rate cases are extremely complicated, and it is beyond the purview of this pamphlet to describe (or discuss) how rate cases are conducted. Here it will suffice to acknowledge the fact that there are competing interests at work. For example, society wants the electricity system to be safe and reliable; no one wants blackouts. This factor encourages more spending on infrastructure (in order to ensure safety and reliability). On the other hand, no one wants to over-spend on the system by "gold-plating" every part of the system. This factor encourages less spending on electricity infrastructure. Striking the proper balance between spending enough to keep the system safe and reliable, but not over-charging customers by spending more than necessary—that is one of the principal jobs of utility commissions in rate cases.

CHAPTER 2

Renewable Portfolio Standards

Renewable electricity technologies are generally newer than technologies that use fossil fuels; thus the markets for these forms of electricity generation have not been as robust as those for more traditional generation. Consequently, commercial developers of renewable energy projects can have a hard time securing the financing needed to build a project like a wind farm or a large solar array. Renewable Portfolio Standards (RPS) are one way for state governments to support the construction of renewable energy projects. This chapter will explain what RPS statutes are and how they work.

Massachusetts was one of the first states to enact an RPS statute, in November 1997; California was another early adopter, in 2002. Today, five of the six New England states have mandatory RPS laws (and the sixth, Vermont, has a voluntary renewable energy goal). In all, 29 states have mandatory RPS laws, including New York, Pennsylvania, Texas, Ohio, Illinois, Arizona, and New Mexico. These RPS statutes are written into state law, because there is no federally mandated RPS at the national level.

RPS LAWS: THREE KEY FEATURES

Although there are variations that exist between the RPS statutes of different states, all RPS laws utilize the same three basic features: mandates, Renewable Energy Certificates, and Alternative Compliance Payments.

MANDATES

Every RPS law starts by creating a mandate, or obligation, that electricity utilities buy a certain percentage of their electricity from renewable energy sources. Those obligations increase over time, usually annually. Some states also provide that the rate of annual increase will also increase over time. In addition, RPS statutes specify what counts as being "renewable." Massachusetts and Rhode Island's RPS statutes provide an illustration.

The Massachusetts RPS statute was signed into law in November 1997, and appears at Mass. Gen. Laws ch. 25A, § 11F. The law required that a baseline be set of the amount of renewables in the system as of two years after enactment, by December 31, 1999. Then, starting in 2003, utilities had to increase the amount of renewables from that baseline by one half percent per year, every year between 2003 and 2009; and then increase the quantity of renewables by one percent per year, every year after 2009. (That is, the amount of renewables increases every year; and the annual rate of increase went up once, in 2009.) The statute specifies what counts as "renewables"—among other technologies, solar photo-voltaic cells (PV), wind, geothermal, and landfill gas.

The Rhode Island RPS statute was enacted in June 2004, and appears at R. I. Gen. Laws § 39-26-1, et seq. The law specified that, starting in 2007, utilities had to procure three percent of their electricity load from renewables. The annual percentage goes up one half percent per year between 2008 and 2010, then the rate of increase goes up to one percent per year between 2011 and 2014 and one and a half percent per year between 2015 and 2019. This should yield 16% of electricity sold in Rhode Island coming from renewables in 2019. Like the Massachusetts statute (and others), the Rhode Island law specifies what counts as renewable energy—again solar PV, wind, geothermal, and landfill gas, among others.

Note that there is generally some lead time between when the RPS statute is enacted and when it first goes into effect. In Massachusetts, that lead time was six years: the RPS statute was passed in 1997, but the first obligation did not apply until 2003. In Rhode Island, the RPS statute was passed in 2004, but did not go into effect until 2007. Note also that the annual increases in the renewable mandates in RPS laws are incremental and distinctly modest, sometimes as little as an additional one half percent per annum. Both of these factors stem from a recognition that the planning, siting, permitting, and construction of all electricity facilities—including renewable energy facilities—take time. Nevertheless, how aggressive the rate of annual increase should be continues to be a matter of public-policy debate; environmentalists have consistently argued that RPS statutes could become effective sooner and could ramp up faster.

RENEWABLE ENERGY CERTIFICATES (RECS)

RPS statutes create "Renewable Energy Certificates" (RECs). These RECs are virtual documents, not real paper documents. Every renewable energy generator (say, the owner of a wind farm) creates one REC for every megawatt-hour (MWh) of renewable energy she produces.

RECs serve two important functions in the broader scheme of RPS statutes: keeping track of renewable energy purchased, and funding renewable energy development.

- RECs are the accounting system by which utilities demonstrate their compliance with RPS laws. Each year, utilities with RPS mandates buy enough RECs to satisfy their RPS obligation for that year. This is how the public (and the state utility commission) know that the utility has complied with its RPS mandate under the law; it is the utility's purchase of RECs that demonstrates compliance.

To illustrate with a couple of simple examples: if National Grid is the utility, and Grid sells 100 MWh of electricity in, say, Rhode Island this year, and Grid's RPS obligation (under Rhode Island law) this year is 7%, Grid must purchase 7 RECs in order to satisfy its obligation. The calculation is simple: 7% of 100 = 7. If next year the RPS obligation ramps up to, say, 8% of Grid's load, and Grid sells 110 MWh of electricity, then next year Grid must buy 8.8 RECs, because 8% of 110 = 8.8.

- RECs create a second stream of income for renewable energy generators. All electricity generators have one main source of revenue and income: they sell their electricity and get paid for it. If you produce electricity, whether it is from coal or from wind, you will get paid for selling that electricity. But renewable generators have a second commodity to sell: RECs; and RPS laws have created a mandatory market for that second commodity because utilities must buy RECs in order to satisfy their annual RPS obligations. This is the way RPS laws create a financial incentive for renewable energy.

RECs can be used in other ways, too, because, like many commodities, there is a secondary market for RECs. For example, in 2006, the Okemo ski area, in Ludlow, Vermont, advertised that it was using 100% renewable energy to run its lifts and light its ski lodges. The way Okemo could do this was that it bought enough RECs to off-set 100% of its electricity consumption. In fact, any individual home-owner or renter, business, college, or other institution can use 100% renewable electricity—by buying enough RECs every year to match its electricity use.

There are also companies that serve as "REC aggregators." One such company, in Massachusetts, is Mass Energy; its affiliate in Rhode Island is called People's Power & Light (PP&L). Each of these companies has thousands of individual electricity customers who are members. When you sign up to be a customer of one of these REC aggregators, you continue to get your electricity from your regular utility (say, National Grid or NSTAR), and you continue to receive a monthly bill from that utility. However, the bill that you receive will have one additional line item on it with a small, additional, incremental charge. That extra money will go to Mass Energy (or PP&L), which will use that money to buy enough RECs to offset 100% of your personal use of electricity. These entities are called "REC aggregators" because they buy RECs for all of their thousands of customers. In this way, any customer can elect to use 100% renewable energy in her home.

ALTERNATIVE COMPLIANCE PAYMENTS

What if a utility under an RPS mandate wants to comply with the law (that is, buy RECs), but there just are no RECs on the market? In theory, this can happen if and when there are not enough renewable energy generators producing RECs. That's where Alternative Compliance Payments (ACPs) come in. RPS statutes allow utilities to satisfy their RPS obligations by making a payment in lieu of purchasing RECs, known as an ACP. Often these ACPs go into a state's Renewable Energy Fund. The cost of ACPs varies from state to state, but generally cost about $60 per MWh each.

ACPs play two crucial roles in the overall RPS arrangement: continued financial support for state renewables development programs, and serving as a price ceiling for RECs.

- State Renewable Energy Funds use their money to help fund new renewable energy projects. (Remember: ACPs must be purchased/paid if there are not enough RECs on the market.) Thus, if there is ever a shortage of RECs on the market, money paid in the ACP is used to build new renewable energy resources, so that the REC shortage disappears in future years. That is, ACPs are a self-correcting mechanism that fix REC shortages if such shortages ever occur.
- ACPs also effectively set a ceiling price on RECs, so that the entire RPS program can never get too expensive for customers. If market forces (that is, supply and demand) were ever to cause REC prices to rise above the ACP price (about $60 per MWh), utilities could simply make an Alternative Compliance Payment (instead of buying those too-expensive RECs).

ALL THREE PARTS OF THE RPS WORK TOGETHER

In practice, the three parts of these RPS statutes work together to form a coherent whole:

- The first part of the RPS construct legally mandates electricity utilities to procure renewable energy; the obligation ramps up over time; and the law defines what counts as "renewable."
- The second part of the RPS construct creates RECs. RECs function as an accounting tool to ensure compliance by the utility, and create a second stream of income going to owners of renewable energy generation. This is crucial, because renewable energy is still generally more expensive than electricity from fossil fuels.
- The third part of the RPS construct creates ACPs. ACPs put a cap on REC prices, so the program can never get too expensive; and Renewable Energy Funds function to correct any temporary shortages that may occur in the REC market by funding new renewable energy generation.

RPS statutes have existed for close to two decades, and they have proved to be a highly effective means of getting real renewable energy projects built.

CONTROVERSIES

RPS statutes do not address every issue pertaining to renewable energy. We consider here some controversies that exist around RPS statutes.

Long-Term Contracts—While renewable energy developers often need long-term contracts (called "Power Purchase Agreements") with utilities (by which they sell both the energy that they generate and RECs) in order to secure sufficient funding for their projects, many (perhaps most) utilities elect to buy only RECs on the spot market. This does not help renewable developers as much as it could, and some states (such as Massachusetts and Rhode Island) have supplemented RPS statutes with separate laws requiring utilities to enter into long-term contracts for renewable energy.

Cost—As discussed above, RPS statutes (using the REC mechanism) create a second stream of income that goes to renewable energy developers. This is paid for by a small additional charge paid by every electricity customer. This fact has led some customer advocates and advocates for low-income customers to oppose RPS statutes. There is no gainsaying the fact that RPS programs cost customers money; of course, environmentalists argue that the significant carbon-emission reductions and other environmental benefits are worth the slight extra cost up front. (And see Chapter 5 for discussion of how renewable energy sources can reduce prices in organized electricity markets like New England's.)

Rate of Increase—There are, of course, always discussions about what the appropriate or "correct" rate of annual ramp-up should be for these statutes. And while it is certainly true that renewable energy costs more than electricity from fossil fuels, it is also true that one of the benefits of RPS statutes is that the per-unit cost of renewable energy projects comes down as these statutes force build-outs of renewable energy projects over time, technology improves, and economies of scale are realized.

Uneven National Effects—Although a majority of states now have RPS statutes, many states do not. Moreover, there is a national patch-work of statutes that contain different ramp-up rates and that allow different technologies to be considered "renewable." While the 29 existing state RPS statutes have been extremely effective in getting renewable energy projects built and operating, a patchwork of different state laws is not a substitute for a coherent national policy.

CHAPTER 3

The ISO: The Independent System Operator

WHAT IS THE ISO?

"ISO" (or "ISO-NE") is the acronym for the Independent System Operator-New England. The ISO is an independent, non-profit corporation that is responsible for keeping the lights on in New England. It is based in Holyoke, Massachusetts, where it has a control room that operates the electricity grid for the six New England states. ISO-NE has an annual budget of $146.6 million (in 2015), and 586 staff people. The staff includes electricity engineers, economists, and other technical experts.

ISO-NE ORIGINS AND AUTHORITY

Interstate markets in electricity are regulated by the federal government under the Federal Power Act (FPA), originally passed in 1935. The FPA created the Federal Power Commission; in 1977, Congress amended the FPA to change the Federal Power Commission into the Federal Energy Regulatory Commission (FERC), and gave FERC expanded powers. Today FERC oversees interstate wholesale energy markets and transmission systems under the authority of the FPA.

In 1996, FERC issued what it called Order 888, which encouraged the creation of ISOs to run and oversee electricity wholesale markets, which were then emerging as states were increasingly moving to restructure the power generation sector to rely on competitive markets rather than vertically integrated utilities. (See Chapter 1 – Deregulation.) In the late 1990s, New England states enacted laws restructuring the power generation sector in whole or in part. (See Chapter 1.) In 1997, in response to FERC Order 888, ISO-NE was formed.

There are other ISOs in the country, including New York ISO (NYISO), California ISO (CAISO), and Midwest ISO (MISO). PJM Interconnection LLC is the ISO for all or parts of 13 states that originally included New Jersey, Pennsylvania, and Maryland (but has now expanded to additional states). The top map on page 16 shows the geographical footprint of ISO-NE; the bottom map on page 16 shows the footprint of all the ISOs in the country. ISOs cover about three-quarters of the United States; in the remaining quarter of the country, vertically integrated utilities own and operate all aspects of the electricity system without an ISO.

WHAT DOES ISO-NE ACTUALLY DO?

As it says on its website, ISO-NE performs three distinct, but inter-related roles. See http://www.iso-ne.com/about/what-we-do/three-roles.

The three roles that the ISO performs are: (1) operates the electricity grid in real time; (2) designs and administers the markets that set wholesale electricity prices; and (3) plans for the future of the grid and the markets. Let's take a look at each of these functions.

1. ISO OPERATES THE ELECTRICITY GRID IN REAL TIME

First, ISO-NE runs the New England electricity grid in real time. There are approximately 81 large power generation facilities in New England, and it is the ISO that decides which ones are on and which ones are off for every one of the 8,760 hours in the year. The process of deciding whether a generator will be on or off is called "unit commitment." The ISO "commits" a power plant when it directs a power plant operator to turn that unit on. Merely deciding which units to commit and when is a very (very!) difficult task, because 280 is a very large number, indeed. That is, there are 280 different combinations of ways that the 80-plus power plants in New England can all be either on or off at any given time.

Running the grid in real time also involves deciding how to "dispatch" each generator—that is increasing or decreasing its power output (once it is committed). Most generators are able to produce different amounts of electricity; the process of telling a generator to produce more (or less) is called "dispatching" that generator up (or down). (Technically, "unit commitment" is the correct nomenclature for the on/off decision; and "dispatch" is the correct nomenclature for ramping up or down. However, colloquially, the "dispatchability" of a generator is often understood to mean whether an ISO can turn it on or off at will.)

Because electricity cannot be stored in significant quantities using existing technology, the ISO must keep the output of all 80-plus generators in New England equal to the consumption (called "load") of all 13 million New England electricity customers for every hour of the year. This, too, is complicated, in part because load varies hour by hour, minute by minute, and second by second as millions of end-use customers turn millions of electric appliances on or off.

Running the grid in real time is made even more complicated by the fact that not every generator is equally able to send electricity to every geographical location in New England. In particular, there are transmission constraints on the New England electricity grid that make it difficult to get electricity into or out of certain geographical areas. One of the better known export-constrained geographical zones is the state of Maine; there are not enough high-voltage transmission lines to get the full output of wind farms and other power plants out of Maine and to the rest of New England. One of the better-known import-constrained zones is NEMA-Boston (see top map on page 14); there are not enough high voltage transmission lines to move power freely into this area during certain hours of the year. ("NEMA" is an acronym for "North Eastern Massachusetts." The NEMA-Boston load zone is, as the name implies, in northeastern Massachusetts, including some of the northern Boston suburbs.) In fact, there are over 1,200 small, geographical pockets around New England that have some type of transmission constraint under certain system conditions.

2. ISO ADMINISTERS THE MARKETS THAT SET WHOLESALE ELECTRICITY PRICES

Second, ISO-NE runs the wholesale electricity markets in New England that ultimately determine the retail rates for electricity that will be paid by all end-use electricity customers in New England. These wholesale markets can be divided into three sub-categories: (1) electricity; (2) capacity; and (3) regulation.

The electricity market, in turn, is divided into a Day Ahead Energy Market and a Real Time Energy Market. Electricity utilities that distribute power to households and businesses (also called "Load-Serving Entities," or "LSEs") get much of their electricity (about 65%) from generators in the form of medium-term or long-term contracts of varying lengths of time. These contracts are handled outside the ISO markets, and long-term contracts typically must be approved by the state public utilities commission that regulates the LSE's services. The LSEs then buy most of the rest of the electricity that they need to serve load (about 30% of the total) in the Day Ahead Energy Market. The remaining electricity that the LSEs need to serve load (only about 5% of the total) is purchased in the Real Time Energy Market.

ISO-NE tries to keep electricity prices as low as possible by buying the cheapest power first; for a more detailed discussion of how electricity prices are set in the Day Ahead and Real Time markets, see Chapter 5. The total value of the electricity market in New England is about $9.1 billion per year. This works out to an average of about 6.2¢ per kilowatt-hour (KWh); however, actual rates vary between different rate classes (for instance big industrial entities are charged in a different way than residential customers) and between different geographical locations.

Whereas the electricity market involves the sale of actual electrons flowing through wires, the capacity market is different. The capacity market involves a commitment to produce electricity at a time three years in the future if called upon by the ISO to do so. Under federal law, the ISO is responsible for system "reliability," and, through the capacity market, ISO ensures that there will be enough generators on the system in the future to produce enough electricity to keep the lights on (that is, to meet the anticipated load). This ability and willingness to produce electricity in the future is called "capacity"—it is really the capacity (willingness and ability) to produce power in the future (if called upon by the ISO to do so). The capacity market is significant; while for many years, this ran to just over a billion dollars a year, in 2015 the capacity auction cleared at over $3 billion for future capacity (or over 2¢ per KWh). For a more detailed discussion of the capacity market (including the "Forward Capacity Auction," descending clock, and "Pay for Performance,") see Chapter 5I.

In contrast to the electricity and capacity markets, both of which are very large and involve billions of dollars per year, the regulation market is relatively small—only about $326 million per year in New England (or 0.2 ¢ per KWh). In the regulation market, specially equipped generators respond to instructions from the ISO to increase or decrease their output every four seconds, in order to keep the proper voltage on the entire electricity grid. While the regulation market is relatively small in dollar value, it is a necessary and important part of running the electricity grid in real time and keeping the lights on for all New Englanders.

All three of these markets are run by ISO-NE: the electricity market (both Day Ahead and Real Time), the Capacity Market, and regulation market. And the sum total of these three markets set the prices that all end-use electricity customers in New England pay for the electricity they use.

3. ISO PLANS FOR THE FUTURE OF THE GRID AND THE MARKETS

Third, ISO-NE does planning for the future. For example, the ISO has to make a prediction every year about how much electricity capacity to buy for the future. In order to do that, the ISO must look at how much electricity is needed in New England now; then estimate how much load growth there may be in the future; then calculate how much of that anticipated growth may be offset by energy efficiency and small distributed renewable energy (like rooftop solar installations on individual homes).

The ISO's planning also includes deciding how much new transmission is going to be needed (and where). The ISO bases these decisions on many factors, including where population centers are developing and where new generation assets (power plants) are being located.

The ISO's planning also involves making necessary (or desirable) adjustments to market rules to accommodate new developments in the electricity grid. For example, in recent years the ISO has changed market rules to accommodate integration of intermittent renewable resources such as wind and solar power.

NEPOOL AND ITS ROLE

NEPOOL is the acronym for the "New England Power Pool." NEPOOL was established in 1971 and consists of a wide range of "Market Participants" including electricity generators, owners of transmission, and customers. For many years, NEPOOL served many of the functions that ISO-NE serves today.

As noted above, in 1996, FERC, in its Order 888, encouraged the creation of ISOs. In 1997, in response to the FERC Order, NEPOOL created ISO-NE as an independent, nonprofit corporation, governed by its own Board of Directors. From then on (continuing today), NEPOOL has served as the official stakeholder group of ISO-NE. CLF is a full member of NEPOOL, and it is through its membership in NEPOOL that CLF can, and sometimes does, influence the ISO's decision-making process.

The relationship between ISO-NE and NEPOOL is a formal, legal relationship that is governed by an 83-page legal document called the "Participants Agreement." In actual practice, these are the major, salient points of the relationship between the ISO and NEPOOL:

The ISO is obligated by law to consult with NEPOOL whenever ISO wants to change the written rules that govern the way it operates the electricity grid or any of the markets. In fact, ISO consults extensively with NEPOOL at formal meetings that occur multiple times every month.

All changes to the written rules that govern the way ISO operates the grid or the markets must be submitted to NEPOOL for a vote before the ISO can file a request for those changes with FERC. To be clear, NEPOOL agreement with a rule change proposed by the ISO is not required; ISO can (and sometimes does) ask FERC for rule changes that NEPOOL opposes. But FERC takes NEPOOL's views into account in making its decisions about ISO requests; and sometimes FERC will agree with NEPOOL, not ISO. For example, in December 2014, ISO and NEPOOL disagreed on the amount of capacity that should be bought in Forward Capacity Auction-9 (FCA-9), to be held in February 2015. (For background on what FCA-9 is, see Chapter 6.) In FERC's decision, issued in January 2015, FERC agreed in part with ISO, but also agreed in part with NEPOOL. (CLF has additional information on the meaning of FERC's decision on this blog on the CLF website: http://www.clf.org/blog/clean-energy-climate-change/ferc-agrees-clf-isos-big-mistake-not-counting-renewable-energy/.)

Importantly, NEPOOL members (like CLF) have legal standing to challenge ISO decisions before FERC. In notable cases, FERC has sided with CLF and against ISO. For example, in 2010, CLF brought a challenge before FERC of an ISO decision not to close down the dirty, old Salem Harbor (Massachusetts) coal-fired power plant; ISO believed that the plant was needed to keep the New England electricity grid reliable. In December 2010, FERC sided with CLF and against ISO. As a result, Salem Harbor coal plant was shut down by its owners.

Everything ISO-NE does is ultimately governed by the FPA and is overseen by FERC. When the ISO wants to change its rules that pertain to any of its functions (running the grid itself, and running the wholesale markets that set prices), the ISO must file those changes with FERC, and wait to implement the proposed changes until FERC has approved them.

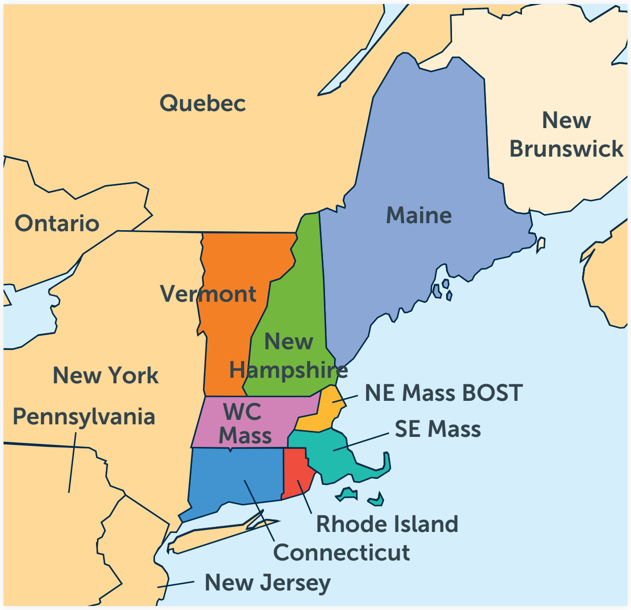
WORKING WITH BOTH ISO AND NEPOOL

CLF is almost alone among environmental organizations because CLF participates actively in both ISO planning groups (such as the ISO's Planning Advisory Committee, Distributed Generation Forecast Working Group, and Energy Efficiency Forecast Working Group) and NEPOOL committees (such as the NEPOOL Participants Committee, Markets Committee, Reliability Committee and Transmission Committee).

CLF has two primary interests in working with the ISO. First (as reflected above), CLF works to close down dirty power plants that are fired by coal and other carbon-emitting fossil fuels. As the operator of the New England electricity grid, the ISO makes initial decisions as to whether these plants can safely close down and exit the market. Second, CLF works to promote clean renewable energy such as solar and wind. Many renewable energy sources are intermittent; and the ISO is the entity that writes the rules and does the planning that is necessary to integrate these intermittent renewable energy resources into the power grid.

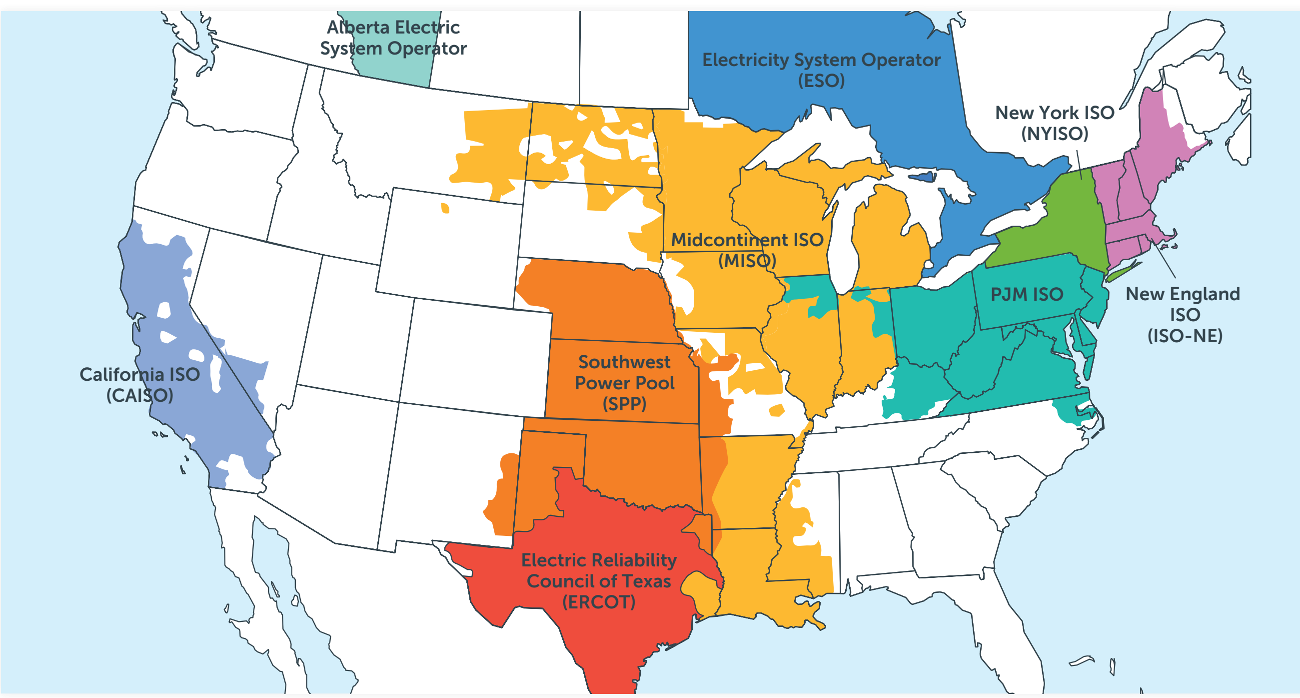
While often quite technical, CLF's extensive work with the ISO and with NEPOOL is both exciting and meaningful, for this is an important place where CLF achieves real-world, tangible results in moving New England and the United States away from dirty, carbon-emitting fossil fuels into a cleaner renewable-energy future.

FIGURE 1. Geographic footprint of Independent System Operator of New England (ISO-NE)



Source: Adapted from Energy Velocity, October 2013.

FIGURE 2. Geographic Footprint of all ISOs in the U.S.



Source: Adapted from the Federal Energy Regulatory Commission www.ferc.gov/oversight

CHAPTER 4

Fuel Mix in New England

Like many regions in the United States, New England once obtained most of its electricity from coal and oil. Over the past two decades, New England's electricity system has been ahead of some other parts of the country in shedding its dependence on the dirtiest fossil fuels. New England is currently undergoing a transition to an electricity system that features renewable power, but it is still dependent on fossil fuels for over half of its power.

The dominant fuel used to generate electricity in New England is natural gas. As the chart below shows, gas generation accounts for about 46% of electricity in New England, nearly as much as every other fuel combined. Nuclear power accounts for about 33%, large Canadian hydro power about 6%, and other renewables (excluding large hydropower) are about 8%.

TABLE 1. Regional electricity generating capacity and energy production by fuel type

New England Generators by Fuel Type	% of Electricity
Natural Gas	46%
Oil	<1%
Nuclear	33%
Coal	6%
Large Hydro	6%
Pumped Storage	1%
Other renewables (excl. large hydro)	8%

It is important to remember that ISO-NE runs a single, unitary electricity grid that covers all six New England states. (See Chapter 3 .) Within that grid, electricity flows, essentially, from all generators to all end-use customers.

Thus, the fuel mix reflected in the chart above is identical for every state in New England, and for every city and county in every state. Thus, for example, the electricity actually used in Maine or Rhode Island is about 33% from nuclear power, even those two states do not have a single nuclear generating station. Similarly, although the very small state of Rhode Island has only gas-fired generators within the state's borders, the electricity consumed by end-use customers in Rhode Island is still the same fuel mix as the rest of New England (which is over 50% non-gas-generated). The idea that the kinds of power plants or other power supply sources within the borders of a state that produce electricity is the same as the fuel mix that is consumed within the state is a common misconception among policymakers and the press.

Over the past 15 years, the relative percentages of fuels in the New England fuel mix have changed significantly; the chart below depicts these changes.

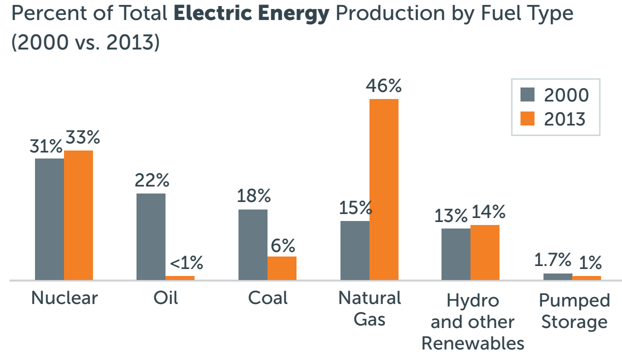
Several specific changes are worth noting. First, the percentage of electricity made using natural gas has increased dramatically. As a result, electricity prices in New England are now closely linked to the price of natural gas. Second, the percentage of electricity from the two dirtiest fossil fuels—oil and coal—has dropped dramatically, from a combined total of 40% in 2000 to under 7% today.[3]

At the same time that dirty oil- and coal-fired generators have been leaving the market, there has been a dramatic and sustained increase in the amount of clean, renewable generation seeking to enter the New England electricity market. The following chart shows ISO-NE's so-called "interconnection queue," the list of new generators seeking to connect to New England's electricity grid. As you can see, 42% of this proposed new electricity, nearly 4,000 megawatts (MW), comes from wind. This is about 400% more than the current total of all renewable resources (other than large hydropower) in New England now.

It is also important to note that the rest of the list of projects attempting to break into the New England market is largely made up of natural gas plants. The growth of renewable energy in New England may slow if public investments in natural gas supply capacity artificially decrease the price of natural gas-powered electricity. For more on how the prices of a particular kind of generation can affect the economics of other kinds of generation, see Chapter 5 – Electricity Prices.

FIGURE 3. Dramatic Changes in the Energy Mix

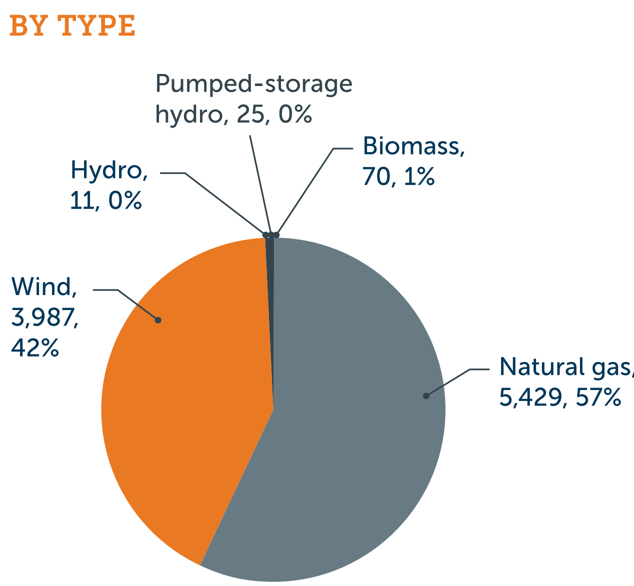
The fuels used to produce New England's electric energy have shifted as a result of economic and environmental factors



Source: ISO New England 2014 Regional Electricity Outlook

FIGURE 4. Generator Proposals in the ISO Queue

Approximately 9,500 MW



Note: Some natural gas include dual-fuel units (oil)

[3] This is, in significant part, because of CLF's Coal-Free New England campaign, which involved bringing a series of successful lawsuits against the owners of coal-fired power plants.

CHAPTER 5

Electricity Prices

The price of electricity is based on many factors. At times we hear about the high cost of new renewable electricity, but in fact our region's reliance on renewable power is helping both to reduce pollution and bring down the cost of electricity.

This chapter examines how electricity prices are set in New England. We explain what the so-called "bid stack" is, and we discuss one of the chief benefits of renewable energy resources—not the environmental benefits, but the economic benefits to customers due to the overall price-reduction effect of renewable resources. (This price-reduction effect is sometimes referred to in the technical literature as a "price-suppression effect.")

HOW ELECTRICITY PRICES ARE SET

ISO-NE runs the wholesale electricity markets in New England, both the Real Time Energy Market, and the Day Ahead Energy Market; it is these markets that directly determine how much customers and utilities in New England pay for electricity. (Customers include all ratepayers—that is, all classes of customers, including residential customers, commercial customers (such as businesses), and industrial customers (such as factories).) (See Chapter 3 for background on ISO-NE.)

The ISO sets electricity prices hourly, with the price for each hour set by the most expensive marginal resource (generator) to be committed for that hour. That is, during every one of the 8,760 hours in a year, the ISO "turns on" the least expense generators first, and turns on the most expensive generators last. The last generator to be committed ("committed" is the technical term for "turned on") sets the price that will be received by every generator that is committed during that hour.

Every generator bids in to these hourly markets, offering to sell its electricity at a certain price. Some generators will bid in at, say, 3¢ per kilowatt-hour (KWh); others may bid in at, say, 5¢ per KWh; others at, say, 10¢ per KWh; and so on. The ISO always arranges the bids in order of cost; and the ISO always "accepts" the lowest bids first. As noted above, this process of arranging the bids in sequential order, with the lowest bids first and the most expensive bids last, creates what the ISO calls the "bid stack." It is called a bid stack because, in effect, the ISO is stacking the bids in order of cost.

Once the bid stack has been made, the ISO starts at the bottom and goes up the bid stack until it has purchased enough electricity to meet the anticipated load in New England for that hour. The last (that is, most expensive) generator to be used in a certain hour is called the "marginal unit," and it is the price of this marginal unit that sets the clearing price that all generators (that clear) will be paid for that hour.

In this system, generators do not get paid according to the price at which they bid their electricity. Instead, every generator gets paid the same price for the same hour. That price is called the "clearing price" for that hour; and the clearing price for each hour is set by the last, marginal (most expensive) unit (at the top of the bid stack) to be committed by the ISO for that hour in order for the ISO to get sufficient electricity to meet the anticipated load for that hour.

The ISO will commit (that is, use the electricity from) every generator that bid in for that hour at or below the clearing price for that hour; the ISO will not commit (that is, not use the electricity from) every generator that bid in above the clearing price for that hour. (Thus, generators have an economic incentive to keep their bids as low as possible, because if they bid in above the clearing price, they will not be committed for that hour; thus, they will not sell any electricity; and they will receive zero dollars for that hour.)

This method of pricing electricity explains the well-known phenomenon that electricity prices are highest on the hottest afternoons of the summer; because increased electricity use from air conditioning requires the ISO to turn on those last, most expensive generators, and those most expensive generators are setting the clearing price for the entire system.

This method of pricing electricity also explains why the overall clearing price paid by utilities and customers is lowered when more low-cost power is bid in; and the overall clearing price is raised when more high-cost power is bid in: the ISO always starts at the bottom of the bid stack, and always goes up the bid stack only as far as necessary to meet the load for that hour.

THE PRICE-SUPPRESSION EFFECT OF RENEWABLES

Generators generally make their bid offers in accordance with the cost of the fuel that they use to generate electricity. For example, usually oil is a more expensive fuel from which to generate electricity than natural gas; therefore, usually oil-fired generators have to bid in at a higher price than gas-fired generators.

The cost of the "fuel" that renewable resources run on—say, sunshine, or the wind—is zero. Moreover, some renewable energy producers receive compensation from places other than the ISO. We discussed one of those revenue streams in Chapter 2 (RECs that come from state RPS statutes). Another such revenue stream can come from federal Production Tax Credits that are paid to renewable energy resources.

As a result, many renewable energy projects bid in to the New England electricity wholesale energy market at zero dollars for every day and every hour that that resource is available. Such resources that bid in to the Real Time and Day Ahead energy markets run by the ISO are called "price takers," because they will take any clearing price that the ISO sets for that hour. (Another example of a price-taker in the energy markets is a nuclear power plant. Nuclear plants cannot be turned on and off for short periods; they always have to be either running or off. Thus, nuclear plants generally participate in the energy market as price takers. They want to make sure they always clear, and they are willing to be committed regardless of what the clearing price is for a particular hour.)

Remember: all generators get the clearing price for every hour that they are committed, not price that they bid in at. Thus, these "price takers" that bid in at zero still get the clearing price, whether that clearing price is, say, 3¢ per KWh for one hour and then 25¢ per KWh for another hour.

The fact that renewable energy projects bid in to the ISO's energy markets at zero means that the clearing price for all electricity for all electricity customers in New England gets lowered because of the presence of renewable energy at the bottom of the "bid stack" (in fact, at zero). This lowering of electricity prices paid by customers due to the presence of renewable energy on the grid (and its presence in the ISO's bid stack) is called the "price-suppression effect" of renewable energy. It means renewable energy is reducing the overall price of electricity for the region.

The amount of this benefit can be significant. In a recent report by a leading international consulting firm, Charles River Associates (CRA), on the price-suppression effect of the 468 megawatts (MW) of wind power expected from the Cape Wind project, CRA estimated the benefit to customers to be about $185 million annually, or about $4.6 billion over the expected 25-year life of the project. While these figures are controversial, and other experts put the dollar value of the price-suppression effect of Cape Wind significantly lower, they nevertheless show the price-suppression effect of renewable energy is real. The CRA report is titled "Analysis of the Impact of Cape Wind on New England Energy Prices," and is dated February 8, 2010. (You can see the full text of the CRA report on the organization's website, at http://www.crai.com/sites/default/files/publications/analysis-of-the-impact-of-cape-wind-on-new-england-energy-prices.pdf?n=944.)

NEGATIVE PRICE OFFERS

On December 3, 2014, the ISO began allowing generators to bid at negative-15¢ per KWh. Although all generators are technically allowed to bid into the energy market at negative amounts, it is mostly renewable generators who are financially able to do so, because they have revenue from the sale of RECs or tax credits that are paid based on them operating. (See Chapter 2 – Renewable Portfolio Standards.) When generators bid into the energy market at less than zero, those bids are called "negative price offers."

Consider for a moment what "negative-price offers" really mean. When a conventional generator (say, a plant that is fired by natural gas) makes a positive price bid into the energy market (say, 5¢ per KWh), that generator is, in effect, saying, "I'll sell my electricity into the market if the market will pay me 5¢ per KWh for all the electricity I sell." If that generator clears the market for that hour, it will sell electricity and get paid for the electricity that it sells. When a renewable generator (say a wind farm) makes a negative price bid into the energy market (say negative-5¢ per KWh) that generator is, in effect, saying, "I'll sell my electricity into the market—and I'll give the market 5¢ per KWh for all of my electricity the market takes." Remember that the ISO is just a clearing house for these transactions; ultimately, these payments will flow through the ISO to electricity customers.

Negative-price offers are not merely a theoretical possibility. Real-time electricity prices in New England have been negative for several hours every month since this new system was introduced on December 3, 2014.

In addition, starting in early 2016, the ISO is implementing a new rule that will allow renewable energy resources like wind and small hydro to set clearing prices for the first time. (Until then, these renewable resources are allowed to bid into the energy markets, but not to set the hourly clearing prices.) When that happens, negative clearing prices will probably start occurring more frequently than they occur now (as renewable resources set the New England clearing price). When that happens, dirty old fossil-fuel generators (like oil and natural gas) would be forced to pay the ISO money if they want to sell their electricity into the market. And, again, the economic benefits will flow back directly to customers.

THE ENERGY-PRICING PARADIGM IS CHANGING

Renewable energy has been around for decades. Over the past decade, as the public's awareness of the climate change emergency has increased, environmentalists have had some success in promoting renewable energy. But for as long as there has been renewable energy, the overall structure of the argument surrounding renewables has been the same: environmentalists promote renewable energy because it reduces carbon and other dangerous emissions; consumer advocates sometimes oppose renewable energy because it costs more than conventional energy.

That paradigm is now changing. It won't change all at once. But because of the way the ISO runs the energy markets, the general public (including government officials and, indeed, all electricity customers) will more and more see the cost-savings from the price-suppression benefits of renewable energy. This is happening now when renewable generators bid in to the energy markets as price takers, because the price-suppression effect of any price-taker in the market is to depress hourly clearing prices. And it will happen even more in the future as renewables are allowed to set clearing prices, including possibly negative clearing prices that will affect all generators.

Another thing that will happen is that old, dirty, fossil-fuel generators will start losing market share and then they will start losing money. Owners of dirty, old fossil fuel plants know these facts only too well; they recognize something (correctly) that the general public is about to learn: the old paradigm in which renewable energy could be plausibly criticized as being too expensive is changing.

In the new paradigm, renewable energy will be not only cleaner than conventional electricity, but it will be cheaper, too.

CHAPTER 6
Capacity

ISO-NE runs the wholesale markets in New England that determine how electricity is priced, and what retail price is ultimately paid by customers. As we discussed in Chapter 3, in addition to the energy market, there is a separate market for what is called "capacity." This chapter explains what capacity is.

CAPACITY AND ELECTRICITY MARKETS: HOW THEY FIT TOGETHER

Energy is actual electrons running through wires. In contrast, "capacity" is the ability to make electricity at a specified time. The ISO runs both New England's electricity market and New England's capacity market. Although those two markets are related in the sense that electricity resources can participate in both (and customers pay for both), the two markets are not identical. The phrase "electricity resources," here means both conventional generators (like gas, coal, and nuclear), renewable generators (like wind, solar, and small hydro), and energy efficiency.

The capacity market run by the ISO is a three-year forward market. It is often referred to as the "Forward Capacity Market," or FCM.

Once a year, ISO holds what it calls a "Forward Capacity Auction" (FCA) for a one-year period of time three years in the future. The purpose of these FCAs is to ensure that there will be an adequate supply of electricity in the region to meet the expected need for electricity. ISO conducts its annual FCA in February of each year. ISO's ninth FCA (called, appropriately enough, FCA-9) was held in February 2015; FCA-8 was conducted in February 2014; FCA-7 in February 2013; and so forth.

The capacity market is designed to ensure that there will be sufficient electricity supply available in New England in the future. In a Forward Capacity Auction, electricity resources compete for what is called a "Capacity Supply Obligation" (CSO). The specific obligation that resources acquire when they get a "Capacity Supply Obligation" is to meet the need for electricity if and when they are called on to do so by the ISO during the relevant period. Generators that "clear" (bid successfully) in one of these auctions acquire a CSO for a future period; in FCA-9 (conducted in February 2015), the relevant period was June 1, 2018 to May 31, 2019.

Resources that clear in the auction, and get a CSO, will receive a stream of income (called "capacity payments") in the future; and they can use that guarantee of future revenue to collateralize a loan now—that is, use those loan proceeds (now) to build a power plant that can produce electricity three years from now when their obligation starts.

(Note: In the preceding two paragraphs we use the word "resources" and the phrase "electricity resources." This requires a word of explanation. As used here, "electricity resources" certainly means electricity generators, including conventional fossil-fuel-fired generators and nuclear generators. The terms also include renewable generators like wind farms. And, importantly, "resources," as used here also include energy efficiency and demand response, because these resources are allowed to participate in the FCM and acquire a CSO. See Chapter 7 (for energy efficiency in the capacity market) and Chapter 8 (for demand response).)

Thus, in broad terms, the money that goes to generators from the capacity market can be, and often is, used to generate funds to construct electricity generating power plants. The money that goes to generators from the electricity market is used to run those power plants, which is mostly fuel costs.

THE DESCENDING CLOCK

In most auctions (say, selling a Monet painting at an art house) prices start low and ascend. This is because auctions generally move in the direction that the auctioneer wants the bidding to move; in a conventional auction, the auctioneer wants the price to end up as high as possible, so the auction moves upward (ascending). With the FCA, the entity conducting the auction (ISO-NE) wants the prices to end up low, because the ISO wants electricity end-use customers to pay the smallest amount of money possible and still buy the future capacity that is required to keep the lights on. For that reason, the Forward Capacity Auction is run "backwards"—the prices start high and descend with each successive round. This is sometimes called a "descending clock auction."

This is what happens.

First, the ISO decides how much capacity is needed in the auction. The technical term that ISO uses to describe what it needs to buy in these FCAs is "Installed Capacity Requirement" (ICR). The ICR is the quantity of electricity generation ("capacity") that is needed ("requirement") to meet the expected load (electricity usage) during the relevant period. In FCA-9 (conducted in February 2015), the ISO set ICR at 34,189 megawatts (MW). What this means is that the ISO believed that during the year that runs June 1, 2018 to May 31, 2019, the peak electricity load in New England would never exceed 34,189 MW.

Then the ISO begins the descending clock auction by offering much more (about double) the amount of money per MW of electricity than it (the ISO) believes will be the final clearing price of the auction. This relatively high price draws in many more offers than the ISO needs to clear 34,189 MW. So the ISO lowers the offering price in the next round of the auction. At the new, lower price, fewer generators, offering fewer total MWs, bid in; but the total being offered may still exceed the ICR of 34,189 MW. So, the ISO goes to another round in descending clock auction, lowering the offering price yet again.

After several rounds, with the ISO offering a lower price per MW in each round, the ISO will eventually get down to a price where pretty much exactly 34,189 MW will be available. That is the clearing price for that auction. The ISO has, in effect, lowered the price it is offering for capacity sufficient to match the ICR (the amount it needs).

Generators that left the auction in earlier rounds will not acquire a CSO; conversely, generators that remained in the auction until the auction cleared will acquire a CSO. As noted above, generators that do acquire a CSO will receive capacity payments from the ISO starting three years in the future. These capacity payments will be separate from (that is, in addition to) payments that the generators may receive from the ISO by selling electricity. This makes sense. These generators are being paid two separate streams of income, because they are selling two distinct, separate (albeit, related) products: generators receive payments for selling capacity, and they may receive payments for selling electricity. And the ultimate source of the funds that the ISO uses to compensate generators for both of these commodities is the same: the electricity customers of New England.

FCM RE-DESIGN, OR "PAY FOR PERFORMANCE"

During 2013 through 2015, the ISO developed and implemented some significant changes to how the FCM will work in the future. As with all changes that the ISO wants to make to its Market Rules, these changes were discussed at length with NEPOOL members, and then submitted to FERC for approval. (See Chapter 3.) The changes to the FCM went into effect in FCA-9 (conducted in February 2015) and will apply for the first time to the Capacity Commitment Period (CCP) that runs from June 1, 2018 through May 31, 2019.

The basic change that the ISO made was to make stricter rules for resources that acquire a CSO in an FCA. These new, stricter rules apply to all resources that acquire a CSO in an FCM. If a resource with a CSO is called upon by the ISO to meet demand when that electricity is most needed (called a "shortage event" because it is a time when the ISO is running short of needed electricity), and the resource is not able to meet the demand, that resource will have to pay a penalty to the ISO. Conversely, generators that do provide electricity during a shortage event will be entitled to a bonus payment. The entire scheme is called "Pay for Performance" (PFP) because generators are being paid for performing.

This PFP system is designed to be revenue neutral. That is, the ISO will neither make money nor lose money on the overall schema. This is because the net bonus payments to generators that do perform will equal the net penalty payments paid into the system by generators who do not perform.

The underlying purpose or rationale for the new PFP system is to make New England's electricity system more reliable. PFP is designed to make the system more reliable by providing economic incentives to generators to take steps that may be necessary to ensure that they will always be available if called upon by the ISO. For example, a gas-fired generator might install an oil tank next to the generator so that, if gas is less available because it is also being used for home heating, the generator can switch over to oil and keep producing electricity, even without gas. (See Chapter 10 – Gas.)

Although this FCM Re-Design (Pay for Performance) is new, it is generally believed that the result will be somewhat higher FCA clearing prices, because generators will add a risk premium into their FCA bids (to compensate for the risk of penalties). The resulting higher FCA clearing prices will be passed along to electricity customers. The overall bargain is that customers will pay a slightly higher price for capacity; and, in return, they will get a more reliable supply of electricity.

A QUICK LOOK AT TWO RECENT AUCTIONS

In FCA-8 (conducted in February 2014), the ISO failed to acquire all the capacity it said it needed for the CCP that runs from June 1, 2017 to May 31, 2018. The shortfall, such as it was, was very small. In FCA-8, the ISO's ICR (the amount it wanted to procure) was 33,855 MW; the amount of capacity it actually procured was 33,712 MW, a shortfall of a mere 143 MW.

The reasons for the (very small) shortfall were mostly things that environmentalists were pleased about. In the period leading up to the auction (FCA-8), several dirty, old fossil-fuel and nuclear plants decided to close down, partly in response to years of activism by environmentalists:

- New England "lost" 1,535 MW of capacity when the dirty, old Brayton Point coal-fired plant decided to shut down by 2017. (CLF worked for years, ultimately successfully, to close down Brayton Point.)
- New England "lost" 604 MW when the Vermont Yankee nuclear plant decided to close. (CLF also worked for years to close down Vermont Yankee.)
- New England also "lost" another 342 MW when the very dirty old oil-fired Norwalk Harbor Station decided to close.

Each one of these retirements was a good thing.

Even though the auction shortfall in FCA-8 was insignificant, it created a lot of very scary press coverage. One ISO press release on the auction results was headed, in part: "Shortfall in Power System Resources Needed for 2017–2018 in New England." The sub-title was: "Resource shortage pushes up capacity market costs." Another ISO press release said: "The auction concluded short of the capacity required, resulting in higher prices for capacity for 2017–2018 . . . Before the auction was conducted, resources totaling about 3,135 MW announced plans to retire, resulting in an insufficient level of resources in the auction . . ."

Scary headlines and scary broadcast news stories followed. Many politicians were talking about a supposed "crisis" that was looming. Some politicians and others believed that building new gas pipelines into New England was necessary to address the purported "crisis."

In February 2015, the ISO conducted FCA-9, in which the ICR was 34,189 MW. In fact, in FCA-9, the ISO actually cleared 34,695 MW of capacity—that is, 506 MW more than the ICR.

Where a year earlier, the post-auction press narrative was all about shortages and the need for more fossil fuels, after FCA-9 the narrative was all about how well the market is working. The headline on the ISO's press release in 2015 was: "Annual Forward Capacity Market Auction Acquires Major New Generation Resources for 2018–2019." The press release actually said:

"The capacity market is working as designed. The price signals from last year's auction helped spur investment in new resources, including more than 1,000 MW of new generating capacity, which will help . . . meet peak demand in 2018–1019," according to Gordon van Welie, president and CEO of ISO New England . . .

ISO President Gordon van Welie was entirely correct about that. The capacity market is working the way it was meant to work. It is creating the right incentives to ensure that there is sufficient generation capacity in New England. In fact, as the ISO press release correctly stated, the ISO's capacity market re-design was largely responsible for the favorable result in FCA-9.

The results on February 2, 2015, of FCA-9 do not, alone, prove that environmentalists (including CLF) were correct in 2014 to oppose the earlier proposal for new gas pipelines—but the result does provide useful evidence of that fact.

CHAPTER 7

Energy Efficiency

Energy efficiency allows for lowering energy use while providing the same level of service.

One clear example of energy efficiency in operation is replacing older, incandescent light bulbs with newer, LED light bulbs. These light bulbs provide the same amount of light (lumens) while using about 90% less electricity when compared with a standard incandescent light bulb.

Energy efficiency provides a customer benefit because it provides the user with the same service at a lower cost. It also provides an environmental benefit because it lowers carbon emissions significantly.

The first, and most obvious, savings (in both cost and carbon emissions) results from the customer buying less electricity. This is an immediate savings that shows on the customer's next electricity bill.

A second, perhaps less obvious, savings comes from energy efficiency lowering the overall electricity systems' costs for everyone. Our electricity system is built to accommodate the highest load, which occurs only a few hours per year. Expensive, new power plants (costing billions of dollars) and expensive new transmission projects (costing additional billions of dollars) are added to the electricity grid just to cover that peak load for a few hours each year. By reducing peak load, energy efficiency saves billions of dollars on the overall electricity grid by delaying or avoiding the need for new power plants and new transmission lines. (This process of reducing peak load is sometimes referred to as "peak-shaving.") Additionally, increased energy efficiency reduces the amount of power that needs to be generated from electricity plants. This reduces for everyone the pollution and system costs of electricity. In this way, energy efficiency saves money for all electricity customers, including those who did not install energy efficiency measures themselves.

By way of example, the energy efficiency investments in Vermont alone have deferred building over $279 million dollars of new electricity transmission lines over the next decade. The total savings in Vermont for energy efficiency since 2000 is 12.7 million megawatt-hours (MWh). That is equal to the amount of energy that would be produced by thirty-two 50 MW power plants operating all the time for a year, and is enough energy to power every home in Vermont for over 5 years. And, for the reasons mentioned above, these saving accrued to all Vermont customers, not only those who install energy efficiency measures for their own use.

ENERGY EFFICIENCY PROGRAMS

All New England states have programs to support investments in energy efficiency. The foundation of these programs is based on the collective investments in energy efficiency lowering the overall cost of electricity for everyone. As a power resource, energy efficiency is the cleanest and lowest cost resource available. Energy efficiency can be acquired for about 3–4 cents per kilowatt-hour (KWh), while purchasing power supply to meet those same needs costs about 8–10 cents per KWh.

In all New England states, energy efficiency investments are funded in part from a small "System Benefit Charge" (SBC). This is a per KWh charge on electricity that is used. The exact amount is established by each state either by legislation or by a regulatory proceeding. In most New England states, the funding level is set to acquire the efficiency resources that cost less than other available power supply options.

Energy efficiency services are provided by utility companies in some states (Massachusetts, New Hampshire, and Rhode Island) and by a separate entity in other states (Vermont and Maine). Each state also has some independent energy efficiency service providers that provide efficiency services based on contracts with customers.

As shown in the next two sections, energy efficiency participates in both New England's capacity market and New England's energy markets.

ENERGY EFFICIENCY IN THE CAPACITY MARKET

The New England electricity grid is run by the ISO-NE (see Chapter 3); and the ISO does regional planning to ensure the region's future energy needs will be satisfied with the Forward Capacity Market (FCM) (see Chapter 6). Energy efficiency resources participate in the Forward Capacity Auctions, and are able to compete on a level playing field with supply resources (such as fossil-fuel generators) to meet the region's power needs. Efficiency resources can and do bid into the FCM, just as generation sources can. Efficiency resources are then paid for their ability to reduce the need for electricity and reduce the capacity that would otherwise require a generating plant to be available. Since efficiency resources can meet capacity needs at a much lower cost than generation resources, the participation of efficiency in the FCM lowers costs for all New England customers. About 80% of all energy efficiency programs in New England clear in the Forward Capacity Market. The revenue streams that result from these auctions are a significant source of funds for advancing energy efficiency in New England (but there are also other significant sources of revenue for efficiency programs, including the state-mandated SBCs).

The most recent FCM auction (FCA-9, in February 2015; see Chapter 6) drew 367 MW of new energy efficiency resources (that reduce overall demand for electricity). The total energy efficiency that clears in the annual Forward Capacity Auction is now about 1,500 MW.

Because the ISO is responsible for the reliability of New England's electricity grid, the ISO sets rigorous standards, with checks and verification, on energy efficiency resources that bid into the FCM. Just as the ISO has a strict qualification process that must be followed by generators that participate in the FCM, there is also a strict qualification process that must be followed by efficiency providers.

ENERGY EFFICIENCY IN THE ENERGY MARKET

Energy efficiency also participates in New England's energy markets. In Chapter 5 we looked at how electricity prices are set in the ISO-run Real Time and Day Ahead energy markets by the creation of a bid stack. When energy efficiency is present on the electricity grid—as a result of the programs described above—energy demand is lower than it would otherwise be for every hour of the year. This means the wholesale clearing price for electricity will also be lower for many hours of the year (but can never be higher) than they would otherwise be (without energy efficiency).

There is a fancy acronym for this: DRIPE. DRIPE stands for "Demand Reduction Induced Price Effects." For some hours of the year, DRIPE represents a relatively small savings for electricity customers. However, during times of peak load, when electricity prices are highest, DRIPE represents much larger savings for customers.

ISO PLANNING SHOWS THE EFFECTS OF ENERGY EFFICIENCY

In Chapter 3, we saw that one of the three principal functions of the ISO-NE is that it prepares forecasts on future energy needs and resources. For energy efficiency, ISO-NE has forecasted that the region expects about 1,616 gigawatt-hours (GWh) of energy savings annually from 2018 to 2024 and that the reduction in peak demand would be about 212 MW annually over the forecast period.

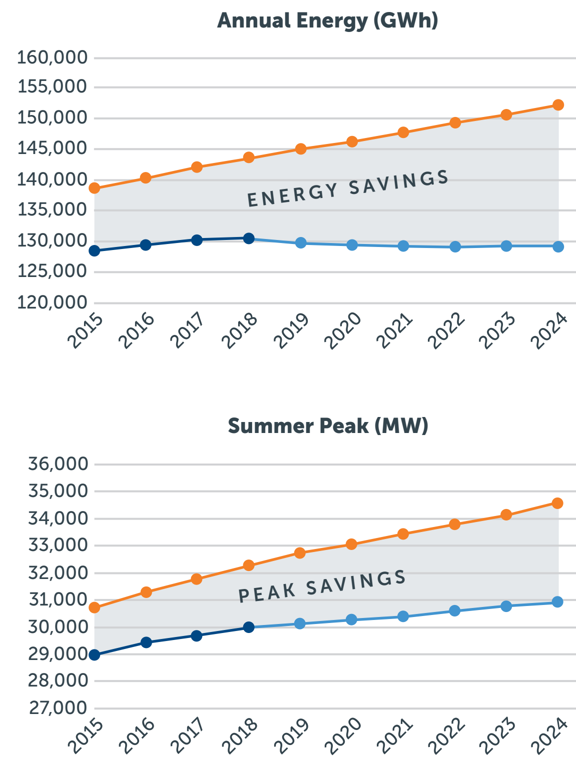
Similar to the individual customer savings for energy efficiency, the demand forecast lowers the overall amount of supply that is needed and that customers must pay for. The fact that the region is meeting growing demand for energy as a result of increased gadgets and other energy uses, while maintaining a flat, and now declining need for supply resources, positions New England well to meet the challenges of increased electrification of transportation and other uses while maintaining lower costs.

The two charts to the right, produced by ISO-NE's Energy Efficiency Forecast Working Group, illustrate the twin benefits (lowered carbon emissions and cost savings) of energy efficiency.

The chart on the top right reflects the amount of electricity that the ISO anticipates will be used in New England each year between now and 2024 (in GWh). The top (orange) line shows the anticipated growth of overall electricity use without energy efficiency programs; the bottom, much lower (blue) line shows anticipated load growth (or decline) over the same period with energy efficiency programs. The difference between the orange and blue lines represents avoided electricity generation due to energy efficiency. Much of that avoided electricity generation would have been from fossil fuels; thus, this avoided generation yields important environmental benefits, including lowered emissions of carbon and other pollutants. These emission reductions are both measurable and significant. To take a single example, the electricity energy efficiency in Vermont cut polluting greenhouse gas emissions by 8.7 million metric tons since 2000. That is equivalent to reducing pollution by taking 1.8 million cars off the road for one year.

The chart on the bottom right shows the anticipated effect of energy efficiency programs on peak load for each year between now and 2024. Again, the top (orange) line shows anticipated increase in peak load without energy efficiency programs; the much lower (blue) line shows anticipated load growth with energy efficiency programs. The difference between the two lines represents the demand that would otherwise need to be met with expensive investments in the overall electricity system (including power plants and transmission lines) that can be avoided because of energy efficiency programs. To take but a single example, the savings from the region's investments in energy efficiency resulted in about $420 million in transmission upgrades that were deferred for New England customers. The region required fewer transmission upgrades as a result of lower energy use. Since transmission costs are now some of the highest and fastest growing costs on customers' electricity bills, these savings provide real and long-term benefits. The pecuniary benefits of these avoided grid-build-out expenses accrue to every customer, including those who did not themselves install energy efficiency measures.

FIGURE 5. Efficiency Programs Save Energy and Cost in New England



Source: ISO-NE's Energy Efficiency Forecast Working Group

CHAPTER 8

Demand Response

WHAT IS "DEMAND RESPONSE"?

Demand Response (DR) refers to electricity customers reducing their consumption of electricity from the grid at times of peak demand. As an alternative to production of additional electricity (say by fossil fuel power plants), DR has two big advantages. First, DR produces no carbon (or other emissions), so DR is environmentally preferable. Second, DR saves customers money, so DR is economically sensible as well.

Electricity demand varies considerably over different seasons of the year and over different hours of the day. In New England, demand typically peaks around mid- to late afternoon on the very hottest days of the year, when air conditioner use is highest. Most days of the year, New England needs no more than about 20,000 megawatts (MW) of electricity to meet the needs of all electricity customers. But on those hottest days, peak demand can spike to about 28,000 MW (that is, 40% more than usual).

This is important because we need enough power plants and transmission lines to accommodate that peak load, even though it only occurs a few hours every year. The power plants needed on peak days are both polluting and expensive. This extra capacity is polluting because these so-called "peaking" power plants (that are only turned on during times of peak demand) are the dirtiest, most polluting fossil fuel power plants on the system. In New England, the plants serving this role are powered by oil or even jet fuel, which are also much more expensive than other power plant fuels and "free-fuel" renewable energy like wind and solar.[4]

DR seeks to lower the cost of electricity and decrease pollution from peaking power plants by reducing electricity load when demand reaches unusually high levels. This can be done in many ways. For example, an individual factory can move a shift of workers from daytime hours to nighttime hours so that its machines will not be running during the day, when electricity demand is highest. Companies can install technology that automatically adjusts air conditioners at, say, a chain of 500 grocery stores (or drug stores or shopping malls) upward from, say, 69 degrees to, say, 73 degrees, so that those stores use less electricity. DR can be controlled through technology so that it can be dispatched, like a power plant, in real-time (so-called "active" DR) or less directly by local actions to turn off equipment or reduce demand (so-called "passive" DR). So far, DR is most common in the commercial and industrial sector; in the future, with Internet-connected appliances and smart electric meters that allow two-way communication between the grid operator and households, residential customers will also be able to be DR providers.

A growing sector of DR companies aggregate users making DR commitments and sell those commitments to an ISO for compensation as an energy resource; this compensation is then shared between the DR aggregator and the electricity customers reducing their demand. These electricity customers thus benefit financially in two separate, direct ways: (1) the compensation they receive for reducing their demand; and (2) the savings they realize from reducing their energy costs at peak times. These savings can be especially significant for large businesses that buy wholesale electricity or pay variable electricity rates.

[4] Keep in mind that these peaking generators may receive two separate streams of income (see Chapter 6: Capacity). First, peaking generators do receive capacity payments if they clear in a capacity auction and are available to be turned on by the ISO. Second, peaking generators may receive energy payments if they actually are turned on by the ISO (during period of peak demand).

When hundreds (or thousands) of separate electricity users all participate in DR programs like these, electricity demand during peak hours can be significantly reduced. DR reduces costs to all electricity customers because it offsets the power that would be generated by expensive peaking power plants that would be running without DR. Because customers pay a blended average of the cost of producing all electricity, using DR to "shave the peak" is an extremely cost-effective way to lower those averages. DR also reduces costs to all electricity customers by eliminating the need to build expensive infrastructure (like power plants and transmission lines), which is only used a few hours or days per year.

(Note that the environmental and economic benefits of DR are less impressive if participating customers reduce their electricity load on the grid but then operate their own fossil fuel, typically diesel-powered, generators to continue operating as usual. Because they are subject to less stringent environmental requirements than larger power plants, these generators can be more polluting than even peaking power plants.)

HOW SIGNIFICANT IS DR?

The Federal Energy Regulatory Commission (FERC) recently published a report that looks at the role and impact of DR in the context of the nation's overall electricity grid. (You can see the full FERC report, here: http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp)

The MW figures that FERC presents are impressive. Here in New England, the ISO can get 2,769 MW of DR, which works out to 10.7% of New England's peak demand. The California ISO has 2,430 MW of DR. PJM has a whopping 8,781 MW of DR. Nationally, there are 28,503 MW of DR on the U.S. electricity grid. (By way of comparison, this is significantly more than the normal, everyday electricity consumption of all homes and businesses in all of the six New England states combined.) FERC concludes that DR is "a quantifiable, reliable resource for regional [electricity] planning purposes."

The dollar figures that this involves are also impressive. For example, the presence of DR in one recent year cut the capacity clearing price by about 50% in the PJM area. (For a discussion of the role of capacity, see Chapter 6. Recall that "PJM" is the ISO that runs the electricity grid for all or parts of 13 states, including Pennsylvania, New Jersey, and Maryland; see Chapter 3.) In other words, if DR were not in the electricity markets, there would be an added expense to electricity customers in the PJM area of over nine billion dollars—in just a single year, and in just one part of the country!

Like energy efficiency resources (see Chapter 7), DR resources are permitted to participate in the ISO-run Forward Capacity Market (FCM) (see Chapter 6). And, as with energy efficiency, the ISO has a strict qualification process that must be followed by DR providers before they are allowed to participate in the FCM.

FERC REGULATES DEMAND RESPONSE

Under the Federal Power Act (FPA), FERC has authority to regulate all interstate sales of electricity and the interstate wholesale electricity markets. The FPA also gives FERC power to regulate everything "affecting" those electricity markets, and the power to ensure that wholesale rates are "just and reasonable."

Over the years, FERC has issued a number of Orders concerning DR. In 2008, FERC issued Order 719, which required ISOs (including ISO-NE) to incorporate DR into their wholesale markets. However, Order 719 also left it to ISOs to determine how much to pay for DR.

In March 2011, FERC Issued its Order 745; the reader can see the full text of Order 745 on the FERC website, here: http://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf. Order 745 instructed all ISOs to pay a certain price for DR. FERC set the price fairly high, because FERC wanted to create an economic incentive for DR to participate in wholesale electricity markets. Specifically, FERC ordered ISOs to pay what is called the "Locational Marginal Price" (LMP) for DR; LMP is the same spot market price that the same

ISO pays for electricity at the same location and at the same time. (And, as we discussed above, the price that an ISO pays for electricity varies from time to time.)

FERC's Order 745 was controversial. By creating strong economic incentives for DR to enter the market, customers stood to save literally (not figuratively) billions of dollars. If DR had not been in the market, customers would unnecessarily have had to pay much more for electricity. A group of generators, the Electric Power Supply Association (EPSA), sued FERC, saying that FERC had no legal authority (jurisdiction) to issue Order 745. The Circuit Court of Appeals in Washington, D.C. issued a ruling in favor of EPSA in May 2014, and FERC's appeal to the United States Supreme Court is currently pending.

CHAPTER 9

Transmission

ELECTRICITY TRANSMISSION

The electricity transmission system is the vast network of poles and wires that carries electric power from power plants to homes and businesses. In essence, the transmission system is a complex machine that balances electricity supply and demand in real time. The transmission system is often divided into two systems:

- the high-voltage "bulk power" transmission system that carries large amounts of power over long distances and often across state lines; and
- the local "distribution" system that connects to the high-voltage transmission grid and brings power to electricity "end-users" (customers).

This chapter addresses three things: (1) how the transmission system has been traditionally operated and funded; (2) how the transmission system is planned and regulated to ensure electricity reliability; and (3) how the transmission system is changing as public policy increasingly drives the deployment of cleaner and distributed energy resources.

TRADITIONAL TRANSMISSION DEVELOPMENT

Electricity utilities are principally responsible for building and owning transmission facilities. Under the Federal Power Act, the Federal Energy Regulatory Commission (FERC) regulates most interstate transmission facilities and the utilities that own them. Local distribution systems and the utilities that own and operate them are regulated by state utility commissions under state law. (See Chapter 1.) In both cases, utilities have traditionally been granted exclusive franchises to provide transmission services within a geographic territory. Investor-owned utilities (referred to as IOUs) recover the costs of developing and operating transmission facilities as well as a reasonable return on their investments through charges approved by regulators and payable by electricity customers. In many cases, power plant owners pay for the transmission facilities that are necessary to connect their generating units with the electricity grid in such a way that there is no resulting adverse effect on the rest of the system.

Historically, transmission development has anticipated and followed growth in electricity demand, as utilities added new customers and new service territories and customer energy needs increased. Utilities, under regulatory oversight, planned new investments in transmission facilities based on their forecasts of electricity demand and system conditions. In some cases, neighboring utilities partnered to develop major transmission upgrades. In several regions of the country, transmission system planning has been assumed by regional transmission organizations, which are discussed below.

Over the last century, the overriding goal of transmission planning and development has been to ensure system reliability ("to keep the lights on") at a reasonable cost but in virtually all circumstances, including times of high electricity demand, power plant or transmission facility outages, and extreme weather conditions. Following a major blackout during the summer of 2003 that affected much of the eastern United States, Congress charged FERC with establishing national reliability standards for the country's transmission system. FERC has designated the North American Electric Reliability Corporation (NERC), a non-profit corporation, as the entity with the responsibility for developing and administering reliability standards. These standards now consist of nearly 3,000 pages of rules and protocols for operating and planning transmission systems, including system performance requirements, communication protocols, security measures, and contingency plans for emergencies. Continuous compliance with these standards can require the development of new transmission lines and upgrades to transmission equipment.

REGIONAL TRANSMISSION ORGANIZATIONS

In several regions of the United States, the operation and planning of the transmission system has shifted away from individual utilities to Regional Transmission Organizations, or RTOs. RTOs are independent nonprofit corporations that administer the power grid under the regulatory oversight of FERC and with the cooperation of the region's electricity utilities, which continue to own and develop transmission facilities. The power industry was encouraged to establish RTOs by FERC Order 888 in 1996, which required utilities to offer non-discriminatory access to transmission facilities. The shift to RTOs closely followed the restructuring of the electricity industry in the 1990s, which introduced competition into the market for power generation in some states by separating the transmission and power plant businesses of electricity utilities.

The nation's RTOs include ISO-New England, the Midcontinent Independent System Operator (MISO), PJM Interconnection LLC (PJM), and the Southwest Power Pool. The New York Independent System Operator and California Independent System Operator have many of the roles and characteristics of an RTO, but their territories are limited to their states. Some regions of the country, including much of the South and the Mountain West, have not restructured the electricity industry and do not have RTOs; the electricity utilities in those regions are individually responsible for planning and operating the transmission system within their territories and are directly regulated by FERC. The transmission system for much of Texas is electrically isolated from the rest of the United States and is administered by the Electric Reliability Council of Texas, an entity similar to an RTO but outside FERC jurisdiction.

RTOs control the operation of the electricity grid around the clock to ensure that electricity supply and demand are balanced across a region. As part of their planning function, RTOs work with electricity utilities and other stakeholders to identify transmission system needs and to approve new transmission projects. With input from these stakeholders, RTOs also draft and revise transmission market rules and regional tariffs for transmission facilities and services, which are reviewed and approved by FERC. Electricity utilities collect the transmission charges authorized by RTO tariffs from electricity customers, and those funds are in turn paid to the electricity utilities that own and build transmission facilities in the region.

(Note: As used here, the word "tariff" has a specific legal meaning. A tariff is a schedule listing the rates charged by a public utility (see Chapter 1) for a public service (like a trip on a ferry) or a commodity (like electricity or gas). Typically, tariffs have to be approved by a federal regulator (such as FERC) or a state regulator (such as a utilities commission) before they can go into effect. Once it goes into effect, the tariff is available to all customers. Electricity tariffs also typically include certain terms and conditions of sale, and these terms and conditions are also subject to regulatory approval.)

In addition to managing the transmission system, RTOs administer wholesale energy and other electricity system markets under FERC oversight. RTOs also work together to manage the flow of power between neighboring regions, most of which have numerous transmission connections, and to engage in interregional planning.

TRANSMISSION FOR CLEAN AND DISTRIBUTED ENERGY

Utilities and RTOs are just beginning to adapt to the rapid growth of clean and distributed energy resources, which are often encouraged by federal and state public policies. These resources have important differences from the conventional power plants around which our transmission system originally developed. In the case of solar power, for example, solar generation can be located at any customer's home or business and both reduces the customer's need for power from conventional power plants and also sends power back into the electricity grid during the sunniest hours of the day. In the case of wind power, wind farms may be located in rural areas where the wind resource is greatest but the transmission system is less developed. With either solar or wind, the output of the resource is dependent on weather; while transmission system operators can use weather forecasts to anticipate their output, they are not necessarily available "on-demand" like conventional power plants.

In 2011, FERC issued Order 1000, which requires a greater degree of regional transmission system planning and coordination by RTOs and utilities, including the consideration of public policies, such as state Renewable Portfolio Standard laws (see Chapter 2) and federal environmental regulations. Order 1000 is one step toward adapting the transmission system to address both its traditional objective of electricity reliability and also the need for and unique characteristics of new clean energy resources.

Order 1000 also calls for RTOs and utilities to develop ways to allocate the costs of transmission upgrades that may be necessary for public policies to be achieved, such as new transmission lines to connect renewable resources in rural areas with electricity customers in urban areas. The allocation of costs for the development of transmission has long been a point of controversy in New England and other RTO regions and has been a limiting factor in the development of transmission to serve renewable energy. Within the ISO-NE region, the cost of building transmission that is designed to serve a regional reliability function, even though located entirely within one state, is paid for by the customers of all New England states through a regional charge on electricity bills. In that instance, the customers in each state pay a percentage of the cost of the project that is calculated based upon that state's percentage of the overall "load" or demand for electricity within the ISO-NE region.

Transmission projects that do not serve a regional reliability function, including those designed to deliver renewable energy to specific markets, must be paid by the customers within the territory served by that transmission. This difference in cost allocation methods has served as a disincentive to develop lines that serve renewables and an incentive for utilities to build reliability oriented projects. With Order 1000, FERC hopes to create mechanisms that will promote more renewable energy-related transmission. In recent years, FERC also has approved and encouraged "merchant" transmission lines that are developed and financed by companies other than incumbent electricity utilities; in some cases, these merchant transmission lines are intended to help meet state public policy objectives.

There is a growing recognition that renewable energy resources, energy efficiency, and advanced energy storage may help reduce the need for costly new transmission system upgrades by reducing electricity demand growth and shaving the peak energy needs during the days and hours of highest demand. (For additional discussion on "peak shaving," see Chapter 5 – Electricity Prices, and Chapter 7 – Energy Efficiency.) Although utilities and RTOs have been slow to recognize the transmission system benefits of these resources, they are beginning to incorporate the growth in clean energy and efficiency measures into transmission planning.

CHAPTER 10

Natural Gas

ROLE IN THE ELECTRICITY FUEL MIX

In New England, natural gas fired power plants are the predominant form of electricity generating capacity interconnected with the ISO-NE grid, representing over 50% of the total. This shift to gas dominated capacity occurred over the last 10–15 years as older coal, oil, and nuclear generation facilities in New England succumbed to economic and regulatory pressures, and were replaced by facilities powered by natural gas and a modest amount of renewable sources of energy. (See Chapter 4.) Natural gas plants require smaller parcels of land than coal and nuclear plants, and are cheaper and easier to build. Additionally, in 2008 the wholesale price of natural gas dropped significantly due in part to increased natural gas extraction from the Marcellus shale formation in the Appalachian region of the U.S. The status of natural gas as the cheapest fossil fuel accelerated the growth of the fuel's proportional role in the New England energy mix.

The displacement of coal and oil facilities with natural gas may have had a net positive effect on greenhouse gas emissions in New England in the early 2000s, as the greenhouse gas emissions from a natural gas burning power plant are lower than those from a coal or oil burning power plant. In recent years, however, more renewable energy (including, but not limited to, wind and solar) has become operational in New England; at the same time, many older, dirtier power plants, including ones that ran on the two dirtiest fuels, coal and oil, have closed. As a result of these changes, overall carbon emissions from electricity generation in New England have declined so much that the carbon-emission profile of a new gas-fired electricity generator is actually higher than the regional average for all electricity generation. That is, on a system-wide level, increased natural gas generation is no longer a net positive for the climate. Further increases in the percentage of system-wide natural gas capacity also tie New England closer to the risks of price volatility in the natural gas market.

WHY THE PRESSURE FOR MORE PIPELINE?

To understand the reasoning cited by proponents of new natural gas pipelines in New England, we must first explore the historical role of natural gas and the current dual role it plays in New England during the winter months.

New England's natural gas pipeline infrastructure was originally built-out in order to serve residential, commercial and industrial gas heating (or thermal) and production customers. The system of pipes is comprised of large interstate pipelines that transmit gas long distances from wellheads to a system of distribution pipelines that deliver the gas to customers. The distribution pipelines are owned by gas Local Distribution Companies (LDCs) that contract with the interstate pipeline to purchase capacity on the interstate pipeline. Interstate pipelines are regulated by the Federal Energy Regulatory Commission (FERC) pursuant to the federal Natural Gas Act. LDCs and their distribution pipeline network are regulated by state public utility commissions, which must approve of both the construction of pipelines and the long term contracts by which the LDCs purchase the gas that they distribute to customers.

Natural gas electricity generators get their natural gas fuel from this same system of interstate and local distribution pipelines. With the increase in natural gas generation in recent years, overall natural gas consumption has increased and put pressures on supplies. The use of natural gas in residential and commercial and industrial heating (thermal use) has been rising along with use of natural gas for electricity generation. As gas prices generally remained low since 2008, homes and businesses (particularly in southern New England) have been converting from fuel oil heating to natural gas.

Local distribution companies for thermal gas have their rates set by their state public utility commissions, and are allowed to recover from customers the cost of fixed contracts with interstate gas suppliers for natural gas capacity. In contrast, the market rules established by ISO-NE for electricity generators do not provide any economic incentive for those generators to make long-term contracts for what is referred to as "firm gas" (gas deliveries that are guaranteed). Instead, electricity generators depend on buying gas on the daily "spot market." Spot market prices are a complicated function of supply, demand, and other market mechanics.

During peak hours of several of the coldest days during the winter of 2013–2014, thermal (for home heating) and electric (for gas-fired electricity generators) demand for natural gas capacity combined with inefficiencies between the natural gas and electricity wholesale markets to cause significant but short-lived "needle" spikes in the price of natural gas. These gas price spikes caused the price of natural gas powered electricity to increase. This resulted in coal and oil electricity generation being more cost effective relative to the market than usual, and those resources wound up running more during discrete periods of the winter.

However, the situation was quite different during the following winter. The winter of 2014–2015 was significantly colder than the previous winter of 2013–2014. But several market forces operated to keep electricity prices significantly lower during winter 2014–2015 than they had been the previous winter. For example, changes made to market rules by ISO-NE created economic incentives for electricity generators to stockpile fuel oil and liquefied natural gas (LNG) (and this, in turn, reduced their reliance on pipeline gas). Also, wholesale prices for oil and LNG were lower in 2014–2015 than they had been the previous winter. These factors combined to prevent the severe needle spikes in the price of natural gas that had been seen during the winter of 2013–2014. Unfortunately, in several states winter electricity rates were set in the fall of 2014 based on wholesale price forecasts that feared a repeat of the previous winter's needle spikes, resulting in a 30% increase in electricity rates for much of New England.

Despite the fact that true capacity constraints due to the confluence of electricity and thermal gas demand were very limited, interstate gas pipeline companies and electricity companies have used the experience of the 2013–2014 winter (and the resulting high electricity rates of the 2014–2015 winter) to argue that New England needs a significant increase in natural gas pipeline capacity. The anticipated retirement of old, dirty and economically obsolete power plants over the next several years had added to this expressed concern for natural gas supplies.

WHY THE OPPOSITION TO NEW GAS PIPELINE?

The overall opposition to new natural gas pipelines in New England is multifaceted and stems from a number of different motivations. Some people oppose increased natural gas infrastructure in any form, some oppose brand new natural gas pipelines but not the expansion of existing pipelines, and some oppose public policy action at the state or regional level to incentivize new natural gas pipeline infrastructure.

The motivation for opposition to new pipelines is generally grounded in environmental and public health concerns, economic concerns, or both. Relevant environmental concerns include: the effects on land and water of pipeline construction and maintenance; the effects of natural gas production at the source, particularly the hydraulic fracturing method of gas extraction used in the Marcellus region of the U.S.; air pollution effects of compressor stations placed along pipelines and from natural gas plants; and greenhouse gas emissions at every point of the natural gas extraction, transmission, distribution, and end use system. Accompanying health concerns include air pollution impacts from pipelines, compressor stations, and natural gas plants, as well as pipeline safety risks.

Economic opposition to natural gas pipelines is based upon the effect that increased natural gas capacity in New England would have on electricity markets and on other types of generation. These concerns are most prevalent with respect to proposed state or regional public policy incentives for increased natural gas transmission capacity. If states intervene in the natural gas market dynamics to artificially inflate the demand for natural gas using customers' money, it will have the effect of depressing wholesale electricity prices and reducing the market signals sent to other types of generation. In particular, there is concern about significantly expanding natural gas capacity where current natural gas market limitations only occur on a handful of days during the year. Existing market generators are invested in the current energy market and are concerned that this privileges natural gas above other forms of energy. Environmental advocates and customer advocates with long-term views of energy costs are concerned that this will result in decreased market incentives for sources of energy with lower greenhouse gas emissions like wind and solar.

WHAT ARE THE EXISTING GAS PIPELINES IN NEW ENGLAND?

New England is served by several major existing natural gas pipelines.

- The Tennessee Gas Pipeline Company crosses southern Massachusetts from upstate New York and extends through the Boston area into New Hampshire.
- The Algonquin Gas Transmission Co. line travels through Connecticut and Rhode Island to Boston.
- The Portland Natural Gas Transmission System (PNGTS) crosses northern New Hampshire from Quebec to Portland, Maine.
- The Maritimes & Northeast Pipeline travels southwesterly from New Brunswick through Maine to northeastern Massachusetts.
- The Granite State Gas Transmission line travels from Portland, Maine to northeastern Massachusetts.
- The Iroquois Gas Transmission System crosses southwestern Connecticut.

Figure 6 on page 38 depicts the current gas pipelines into New England.

WHAT ARE THE PROPOSED GAS PIPELINES IN NEW ENGLAND? AT WHAT STAGE OF REGULATORY APPROVAL IS EACH PROPOSED GAS PIPELINE?

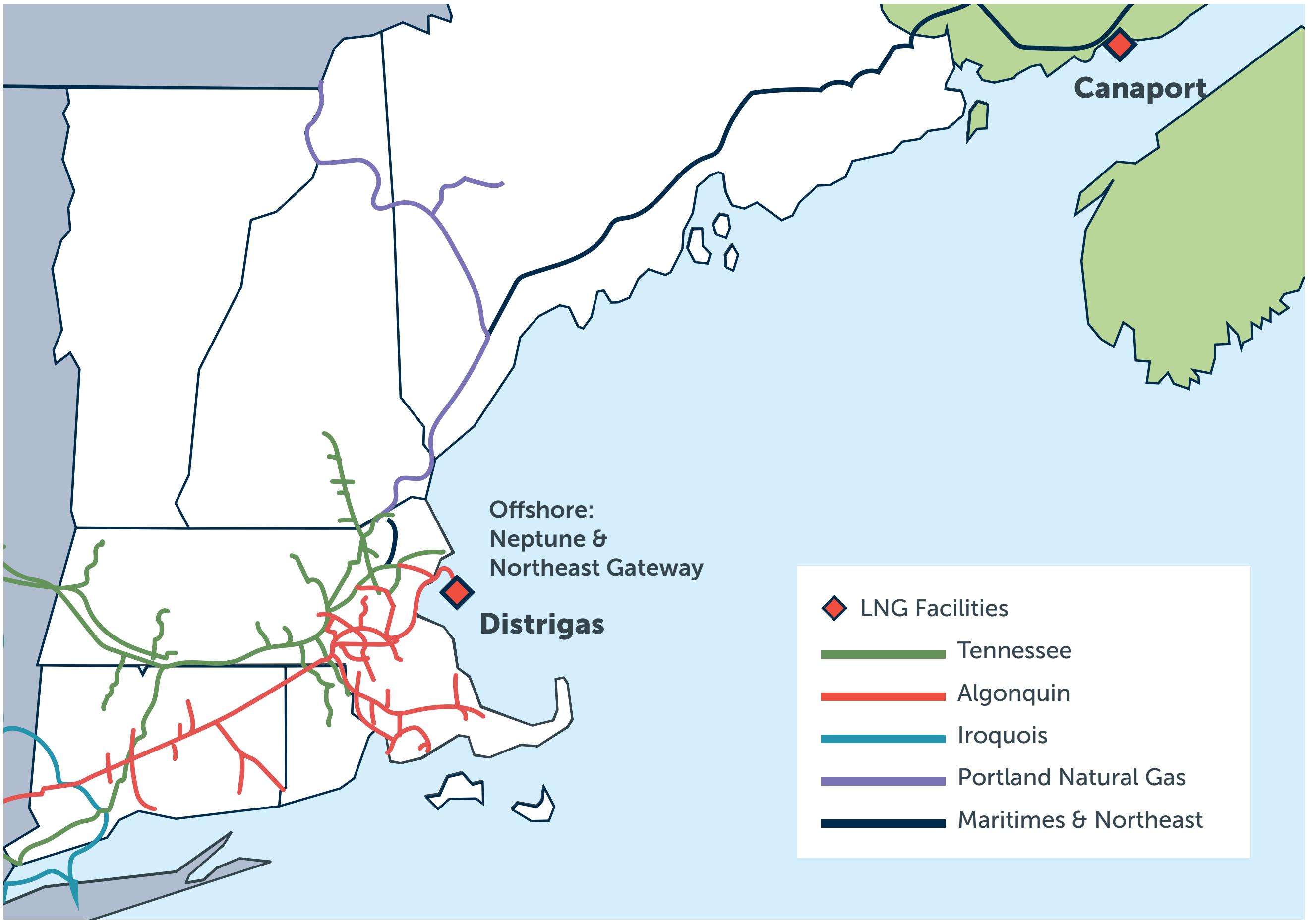
Multiple gas pipeline expansion projects are currently proposed for New England.

- The Algonquin Incremental Market (AIM) project from Algonquin Gas Transmission/Spectra Energy is a proposed incremental upgrade to the existing Algonquin Gas Transmission Co. line.
  — The AIM project was approved by FERC in March of 2015 and is planned to be in service in the second half of 2016.

- The Connecticut Expansion project from Tennessee Gas is a proposed looping project from the current Tennessee Gas Pipeline Company line in Connecticut and Massachusetts.
  — The Connecticut Expansion project is being considered formally by FERC.

- The Continent to Coast (C2C) Expansion is a proposed incremental expansion of the existing Portland Natural Gas Transmission System line.
  — The C2C project is in contract negotiations.

FIGURE 6. Map of New England Interstate Pipelines and LNG Terminals



Source: Adapted from ICF International, http://www.iso-ne.com/static-assets/documents/2014/11/final_icf_phii_gas_study_report_with_appendices_112014.pdf.

- The Atlantic Bridge project from Spectra Energy is a proposed incremental expansion of the existing Algonquin and Maritimes & Northeast lines.

— The Atlantic Bridge project is in the pre-filing stage at FERC.

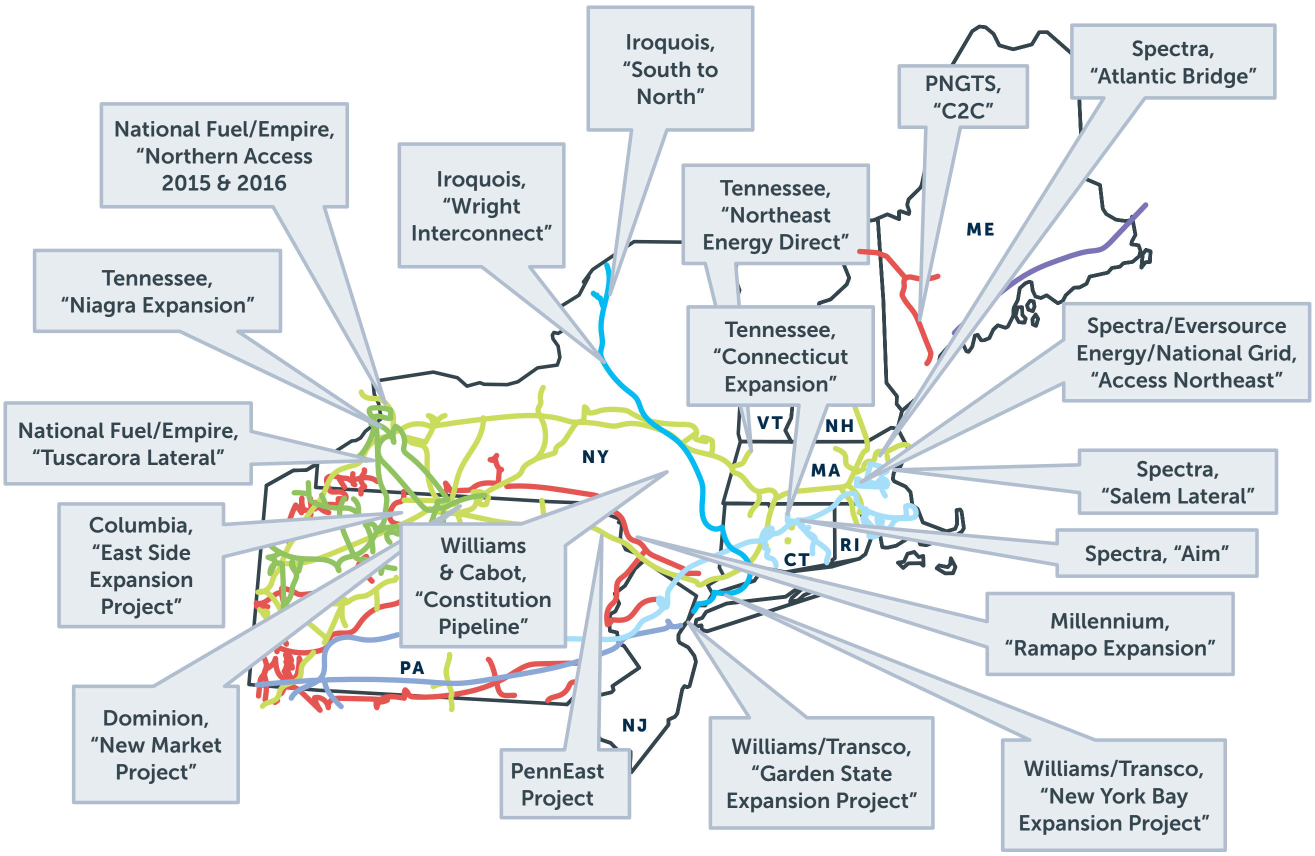
- The Northeast Energy Direct (NED) Project is a proposed new pipeline expansion by Tennessee Gas Company that would travel across northern MA and southern NH to Dracut, MA.

— The NED Project is in the pre-filing stage at FERC.

- The Access Northeast project is a proposed "enhancement" of the Algonquin and Maritimes & Northeast pipeline systems. This project is a joint venture by Spectra Energy and the electricity and gas utilities Eversource Energy and National Grid. It would uniquely involve capacity reserved on the pipelines primarily for electricity generation.

— The Access Northeast completed an open season on May 1, 2015.

FIGURE 7. Proposed Gas Pipeline Expansions



Source: Adapted from NGA, based on publicly available information. Project locations approximate. As of 3-15.

INDEX OF ACRONYMS

ACP (Alternative Compliance Payment)

AIM (Algonquin Incremental Market)

C2C (Continent to Coast)

CAISO (California ISO)

CLF (Conservation Law Foundation)

CRA (Charles River Associates)

CSO (Capacity Supply Obligation)

DPU (Department of Public Utilities)

DR (Demand Response)

EPSA (Electric Power Supply Association)

FCA (Forward Capacity Auction)

FCM (Forward Capacity Market)

FERC (Federal Energy Regulatory Commission)

FPA (Federal Power Act)

GWh (gigawatt-hours)

ICR (Installed Capacity Requirement)

IOU (Investor Owned Utility)

ISO (Independent System Operator)

ISO-NE (Independent System Operator-New England)

KWh (kilowatt-hour)

LDC (Local Distribution Company)

LMP (Locational Marginal Price)

LSE (Load-Serving Entity)

MISO (Midwest ISO)

MW (megawatt)

MWh (megawatt-hour)

NED (Northeast Energy Direct)

NEMA (North Eastern Massachusetts)

NEPOOL (New England Power Pool)

NERC (North American Electric Reliability Corporation)

NYISO (New York ISO)

PFP (Pay for Performance)

PJM (PJM Interconnection LLC)

PNGTS (Portland Natural Gas Transmission System)

PP&L (People's Power & Light)

PUC (Public Utility Commission)

PURA (Public Utilities Regulatory Agency)

PV (photo-voltaic)

REC (Renewable Energy Certificates)

ROE (Return on Equity)

RPS (Renewable Portfolio Standard)

SBC (System Benefit Charge)

T&D (Transmission and Distribution)