



## FACTORS BEHIND CONNECTICUT'S HIGH ELECTRIC RATES

By: Lee R. Hansen, Associate Analyst

### RETAIL ELECTRIC RATES

Retail electric rates are generally comprised of

1. generation service charges (the cost of the electricity itself);
2. transmission charges (the cost of sending the power from the generators to local substations);
3. distribution charges (the cost of sending the power from substations to the customer; and
4. other charges that support public policy initiatives, such as energy efficiency or renewable energy programs.

The average retail price of electricity is typically calculated as the total kWh sold, divided by the total amount of money paid for it.

### ISSUE

This report (1) updates OLR Report [2008-R-0452](#) describing why Connecticut's electric rates are higher than those in most other states and (2) describes measures taken by the legislature since 2008 to reduce electric costs in the short and long term.

### SUMMARY

As of November 2014 ([latest available data](#) from the U.S. Energy Information Administration), Connecticut had the second highest average residential retail electric rates in the country. High rates are a regional phenomenon, and all six of the New England states plus New York are among the 10 states with the highest rates.

We are aware of no empirical analysis as to why Connecticut's rates are so high. However, it appears that several factors that apply across New England and interact with each other are the primary causes. These include (1) the structure of the electric industry in New England, where the vast majority of power is supplied by non-utility generators; (2) federally-

approved wholesale market rules; (3) a tight market caused by growth in demand outstripping supply; (4) the mix of fuels used to generate power in the region and, in particular, the region's reliance on natural gas; (5) environmental standards; and (6) congestion on the state's electric transmission system.

Legislation enacted since 2008 has largely focused on limiting electricity's overall costs by promoting energy efficiency and conservation, rather than by directly addressing electricity rates. These measures can help control an electric bill's bottom line, even though they may not directly affect the cost per kilowatt hour (kWh) used.

In addition to establishing many programs to fund or help customers finance different energy efficiency measures, the legislature has also enacted legislation that changed the power procurement process for the electricity sold under the electric companies' standard service offer. [Public Act 11-80](#), among other things, created a power procurement officer in the Department of Energy and Environmental Protection (DEEP) to oversee the process instead of leaving it to the electric companies. It also allowed the procurements to rely on shorter-term contracts, which made the standard offer rate more responsive to the wholesale market rate. In general, this change allowed the standard offer rate to significantly decrease along with the wholesale market rate from 2011-2013, but it also meant that the standard rate more closely followed the wholesale market rate upward from 2013-2015.

The legislature has also enacted various (1) notice requirements and consumer protections for customers of retail electricity suppliers, which could help them avoid paying higher generation rates when lower ones are available, and (2) renewable energy incentive programs, which can reduce costs for those customers who take advantage of them, and may help reduce demand and congestion-related costs for all ratepayers.

## **WHY ARE CONNECTICUT'S ELECTRIC RATES SO HIGH?**

### ***Introduction***

According to the [U.S. Energy Information Administration](#), as of November 2014 Connecticut had the second highest average residential retail electric rates in the country at 19.87 cents/kWh, compared to a national average of 12.46 cents/ kWh. Connecticut has had relatively high rates for some time. As OLR report [2008-R-0452](#) notes, Connecticut had the second highest rates in the country as of February 2008, the third highest rates as of November 2006, and the fourth highest rates in 1998, when the legislature partially deregulated the electric industry with the passage of [PA 98-28](#).

High electric rates are a regional phenomenon. The 10 states with the highest rates in November 2014 included the six New England states and New York. (The other three states were Hawaii, which had the highest rates in the country, Alaska,

and California.) Excluding Alaska and Hawaii, New England's 17.97 cents/ kWh was the highest average regional rate in the nation, followed by the Middle Atlantic region (16.06 cents/kWh) and the Pacific Coast states (13.81 cents/kWh).

### ***Industry Structure***

Connecticut's deregulation of the electric industry in the late 1990s required the electric companies to sell off their generation assets and buy power on the regional wholesale market. While the Public Utilities Regulatory Authority (PURA) continues to set rates for transmission and distribution on a cost of service basis, the regional wholesale market is under the jurisdiction of the Federal Energy Regulatory Commission, which approves the rules governing this market. The electric companies pass on the cost of the power they buy on this market to their standard service offer customers, but do not earn a rate of return on their purchased power. The cost of this power accounts for the bulk of electric rates.

Customers who do not receive their power through the companies' standard service offer, choose to instead purchase their power through retail suppliers, who also buy their power on the regional wholesale market. Prices from retail suppliers can vary widely and are offered through a variety of fixed and short-term pricing plans. Roughly 40% of the state's residential customers purchase their electricity from a retail supplier and the extent to which a portion of these customers may be paying higher prices than otherwise necessary could also increase the state's average retail price.

### ***Wholesale Market Rules***

The wholesale market has two primary components. Most power is sold under bilateral contracts between electric companies and wholesale suppliers (power plant owners or marketers who purchase power from them and resell it on the wholesale market). The second component is the spot market. The prices set in the spot market substantially affect the prices charged under bilateral contracts.

The prices set in the spot market are not based on the power plants' cost of service. Instead, the Independent System Operator-New England (ISO-New England, the wholesale market administrator) estimates the amount of power needed hour-by-hour for the next day. It accepts bids to provide this power, beginning with the lowest bid, until it has enough supply to meet projected demand. All of the winning bidders are paid the price charged by the highest selected bidder. During periods of high demand (for example weekday afternoons), this price is typically set by plants that use natural gas. However, the owners of power produced by lower-cost nuclear and coal plants are paid the same price. New York state has its own ISO, which has similar rules.

When the wholesale market is tight these market rules can lead to rates that are higher than would apply under the cost of service approach. In a January 1, 2008 filing with PURA's predecessor, the Department of Public Utility Control, Connecticut's electric companies asserted that the cost of service approach for existing and new power plants in the state would result in 2011 electric rates that would be 5.1 cents per kwh lower than would apply under the market rules, with a slightly smaller differential in 2013 and 2018.

On the other hand, when there is ample generation supply on the market, the rates produced under the market rule can be less than those produced under cost of service. This is because plant owners will provide power, even at rates that are below their full cost of service, so long as they are able to at least recover their fuel and other operating costs. In addition, the market rule can increase the efficiency of power plant operations, since their owners do not earn money when their plants do not operate. Under the cost of service approach, the owner continues to recover the plant's capital costs and earn a rate of return on its investments even if the plant is not operating.

### ***Growth in Demand Versus Supply***

Prior to 2008, growth in electric demand, particularly during peak periods, exceeded growth in supply (electric generation) in the state and New England. In New England, the summer peak demand increased from 23,150 megawatts in 2000 to 27,640 megawatts in 2007 (adjusted for changes in weather). The reserve margin of generating capacity over peak summer demand fell from 29% to 10% from 2004 to 2006. According to DEEP's [draft 2014 Integrated Resource Plan](#), peak demand in Connecticut and throughout New England fell from 2008 through 2012, due mainly to economic conditions, but began to increase once again in 2013 and is expected to surpass pre-recession levels in 2015.

Although Connecticut's total demand growth is essentially flat, the growth in peak demand is important because the plants that are used to meet peak demand must be paid for, ultimately, by ratepayers, even if they are used very infrequently. The growth in demand relative to supply puts pressure on rates in several ways. Under the market rules described above, when demand is low, generators use relatively low cost plants. As demand increases, generators are more likely to use more expensive plants. Increased demand also expands the need for power imports from other states, with the associated transmission costs. Increased demand also exacerbates congestion on the state's transmission system, which increases rates as described below.

## ***Fuel Mix***

New England depends more heavily than other regions on natural gas as a generating fuel. During most of the year, natural gas powered plants set the spot market price. In contrast, other regions rely much more heavily on coal as a generating fuel. As coal is a significantly less expensive source of power than natural gas, this difference accounts for part of the difference in rates (particularly in states that do not regulate their coal plants' emissions to the same extent as the New England states do).

Over the past decade, technological advances in drilling techniques have brought substantially more gas to market in North America, resulting in larger quantities of natural gas and lower natural gas prices. At the same time, an increasing amount of New England's electricity comes from natural gas. Many coal and oil plants have been retired or will retire in the near future, and gas-powered power plants are expected to replace them. From 2007 through 2013, the portion of electricity generated from New England's natural gas-fueled power plants increased from 34% to 46%. From 2009 to 2013, these factors helped lower electricity prices in New England.

Interstate gas transmission lines, however, have not expanded in proportion to the increase in supply and demand. Gas-powered power plants generally purchase natural gas through intermittent (or interruptible) contracts, and transmission pipelines generally expand based on firm commitments, thus increased demand from generators has not necessarily led to pipeline expansion.

During episodes of extreme cold weather, when the gas transmission lines are at full capacity due to heating demand, intermittent contracts allow the demand from gas companies supplying gas to residences and businesses on "firm" contracts to take precedence over the intermittent contracts. When this happens, gas-powered power plants lose access to the gas they need to generate electricity and electricity suppliers must buy their power from more expensive, non-gas-powered generators at a premium price due to their limited supply and high demand. These increased prices tend to be passed on to consumers and may lead to dramatic rate increases, particularly in short-term variable rates. This price volatility can increase the price of electricity over time, as has been seen over the past two to three years. For more information about the relationship between natural gas and electricity prices, see OLR Report [2014-R-0267](#).

## ***Environmental and Renewable Standards***

Part of the reason why New England uses more natural gas and less coal than other regions is its air quality standards. The New England states have among the most

stringent emission standards in the country for nitrogen oxides, sulfur oxides, and other pollutants. Emissions of these pollutants from natural gas plants are lower and easier to control than those from coal plants. The New England States also participate in the Regional Greenhouse Gas Initiative (RGGI), a “cap-and-trade” program that subjects power plants in the region to a declining cap on the amount of CO<sub>2</sub> they can emit and allows plants that emit more CO<sub>2</sub> than they are allowed to buy credits from plants that emit less CO<sub>2</sub> than they are allowed. Funds raised by the initiative are used for energy efficiency and renewable energy programs.

In addition, all of the New England states except Vermont have renewable portfolio standards (RPS) that require part of the power sold in these states to come from renewable resources. Connecticut has also directed its electric companies to enter into long-term commitments to purchase electricity from various renewable energy projects (e.g., Project 150, the L-REC and Z-Rec programs). These commitments and the RPS requirements could increase the overall cost of power if the price for the renewables is higher than the price for power produced from other sources. However, renewables may also help mitigate other expenses by limiting increases in peak demand, reducing system congestion and transmission costs, and reducing the need for various distribution system infrastructure upgrades.

### ***Transmission Congestion***

As noted above, in the past, Connecticut’s electricity demand has grown faster than the state’s infrastructure of power plants. As a result, the transmission system became increasingly congested, particularly in the southwestern third of the state. This congestion led to several costs. In order to maintain reliability, older, less efficient plants have to run more often than would have been the case in the absence of congestion. Moreover, congestion decreases the physical efficiency of the transmission lines, which increases the cost of power in the state. These congestion costs have decreased substantially in recent years with the construction of the Bethel-Norwalk and Norwalk-Middletown transmission lines and other projects.

### **LEGISLATIVE RESPONSE**

Legislation enacted since 2008 has largely focused on limiting electricity’s overall costs by promoting energy efficiency and conservation, rather than by directly affecting electricity rates. The legislature has also enacted legislation that changed the power procurement process for the electricity sold under the electric companies’ standard service offer, making it more responsive to the wholesale market rate. The legislature has also enacted various (1) consumer protections for customers of retail electricity suppliers, which could help them avoid paying higher generation

rates when lower ones are available, and (2) renewable energy incentive programs, which can reduce costs for those customers who take advantage of them, and may help reduce costs for all ratepayers.

## **2008**

[PA 08-2](#) (August Special Session) increased the maximum income a household could have to participate in the energy conservation loan program.

## **2009**

[PA 09-8](#) (September Special Session) allowed the state to establish a corporation tax credit for taxpayers who build “green” buildings that meet certain energy and environmental standards.

## **2010**

[PA 10-179](#) required the Connecticut Health and Educational Facilities Authority (CHEFA) to use state bond money to guarantee loans made by participating lending institutions to eligible participants for energy conservation projects.

## **2011**

[PA 11-80](#), among other things:

1. required DEEP to employ an electric power procurement manager to develop a plan for procuring power for the electric companies’ standard service offer;
2. modified how the power for the standard offer was procured by allowing for shorter term contracts that could make the standard offer prices more responsive to market conditions;
3. authorized state agencies and municipalities to enter into energy saving performance contracts (i.e., contracts with third parties to find savings through energy efficiency measures);
4. required DEEP to develop a comprehensive energy strategy;
5. created the Clean Energy Finance and Investment Authority (CEFIA, now known as the CT Green Bank) to administer the Clean Energy Fund and implement a residential solar program that would lead to at least 30 MW of solar generating capacity by 2022; and
6. established the L-REC and Z-REC programs that require electric companies to enter into long-term contracts to buy renewable energy credits from certain renewable energy and low emission generators.

## **2012**

Among other things, [PA 12-2](#) (June Special Session) (1) allowed CEFIA to issue revenue bonds backed by Clean Energy Fund revenues and (2) required CEFIA to establish a property assessed clean energy (PACE) program for qualifying commercial properties.

## **2013**

[PA 13-119](#) required retail electric suppliers to notify residential customers 30-60 days before the customer's fixed price term ends.

Among other things, [PA 13-298](#) (1) allowed for an additional 0.3 cents per kWh charge on electric bills to fund additional energy conservation programs under certain circumstances and (2) required CEFIA to establish a program to finance residential energy efficiency and renewable energy measures using private capital, with loans repaid on the participating customer's gas or electric bill.

[PA 13-116](#) expanded the commercial PACE program to include (1) district heating and cooling (e.g., a cogeneration system that also supplies excess steam or heat to multiple energy consumers) and (2) solar thermal and geothermal projects.

[PA 13-303](#) allowed the DEEP commissioner to (1) solicit proposals from class I and large-scale hydropower generators and (2) direct the electric companies to enter into agreements with them, subject to review and approval by PURA. It allows large-scale hydropower to count towards the RPS under certain conditions. The act also required alternative compliance payments (ACPs) to be used to reduce electric rates, instead of being used to develop new renewable resources. (ACPs are the penalties paid by electric companies and suppliers who fail to meet the RPS).

## **2014**

[PA 14-75](#) prohibited retail electric suppliers from raising rates for the first three billing cycles of new supplier contracts. It also required electric suppliers to notify residential customers in advance of certain rate changes and prohibited them from charging cancellation or early termination fees under certain circumstances. The act also decreased the cap on such fees.

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