

Restoring Power: How Lawmakers Can Lower Your Electric Bill

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EXECUTIVE SUMMARY

Connecticut's residents are getting a shock from their electric bills.

These higher costs squeeze our budgets, reduce the funds available for consumers' other spending priorities, and force employers to slow their growth plans and reevaluate doing business in Connecticut. The Renewable Portfolio Standard (RPS), passed by the legislature in 1998 and modified a number of times since, contribute to the rising cost of electricity and reduce the ability of the state's utilities to decide the best, most efficient, and cleanest way to produce energy.

The first step in reasserting control over our electricity market and reducing prices is to repeal the Renewable Portfolio Standard.

The following paper, written by scholars at the Beacon Hill Institute at Suffolk University, shows that RPS mandates will cost Connecticut:

- \$1.587 billion from 2014 to 2020, or \$453 out of each Connecticut resident's pocket. That's more than \$1,800 for a family of four;
- 2,660 jobs;
- \$283 million in lost real disposable income.

By mandating that utility companies buy a growing percentage of electricity produced by a small list of renewable energy sources, RPS takes a simple problem and complicates it by limiting our energy consumption choices. Instead of forcing consumers to purchase more expensive electricity, the state

could follow the lead of other states and allow consumers to choose their energy's generation sources.

RPS is based on the false promise that Connecticut would develop a "green economy" and create local jobs. Instead, RPS has created jobs in Northern Maine and Quebec, where wood-burning biomass and hydropower plants fulfill our state's RPS mandates.

Higher Prices

Higher energy prices hit the poor the hardest.

The RPS mandates have pushed electricity rates higher, and will continue to do so as the standards become stricter every year until 2020, when 27 percent of the state's electricity must be produced by an approved source of renewable power.

The RPS mandates force electricity providers to buy more expensive energy, because they cannot look for the least expensive option but instead must buy energy from a narrow list of approved sources. This has put on a drag on investment in cheaper energy sources and instead has promoted investment in sources that meet the requirements of the mandates. Connecticut is now further behind other states that have built energy sectors that meet the needs of citizens, and have focused on making traditional sources of energy cleaner.

Where are the promised jobs?

Only a small amount of the energy produced to meet RPS mandates comes from Connecticut – we bear the costs but we don't see the benefits.

State lawmakers told us in 1998 that tax credits and mandated consumption for the “green” energy sector would stimulate growth and lead to more jobs in Connecticut. But they were wrong. The promised jobs, which would supposedly offset the economic loss from higher electricity costs, never materialized.

Instead, our electricity rates continue to go up – even as consumption decreases – and this study shows that only 3.8% of the electricity purchased to satisfy RPS mandates was produced in Connecticut. Most of our money (and those promised jobs) ended up in Maine, where the state’s surplus wood fuels its biomass industry. Our future hope for RPS-approved electricity is based on hydropower from Quebec.

The cost to develop and prop up the “green” energy sector continues to put a drag both on the state’s budget and on the state’s business community – particularly the manufacturing sector, which is an important source of jobs and money for the state’s economy.

These increased costs also hit cities and towns, which have much higher electric bills than the average household.

The RPS mandates also mean the state is involved in picking winners and losers in the energy market, as traditional suppliers are forced offline. In the meantime, we are

supporting the growth of solar and wind businesses that may need government handouts for years in order to survive.

Less Control of Our Energy Markets

The RPS mandates force the state into a predetermined course.

The RPS mandates have reduced our use of sources that can provide energy around the clock and have made us reliant on sources that provide energy only when the climate is just right – because either the wind is blowing or the sun is shining. The unanswered question is what to do when those sources are not readily available, and we no longer have the capacity to meet our needs with more reliable sources of energy.

Finally, because wind and solar energy sources tend to be more distant from population centers, we will likely have to add an additional 4,300 miles of new transmission lines to move energy to our market. That will cost billions of dollars, which will be subsidized by energy consumers.

Looking Ahead

To bring costs down for consumers, and to make Connecticut a more competitive state for business, it is time to repeal the RPS mandates.

– *The Yankee Institute, January 2015*

INTRODUCTION

In 1998 Connecticut became one of the first states to pass Renewable Portfolio Standard (RPS) legislation, and since that time the policy has been amended on several occasions.

Governor Daniel P. Malloy signed S.B. 1138, the most recent changes, into law on June 4th, 2013.¹

The Connecticut RPS mandates that each electric utility obtain at least 27 percent of its retail load from renewable energy generation by January 1, 2020. The mandate started with an initial requirement of 4.5 percent in 2005 and increased incrementally from 0.5 percent and 1.5 percent each year through 2020. The RPS also required each electric utility to obtain at least 4 percent of its retail load by using 1) combined heat and power (CHP) systems and 2) energy efficiency programs beginning in 2010. [For more details see the Appendix.]

To estimate the economic effects of the Connecticut Renewable Portfolio Standard (RPS) mandates, The Beacon Hill Institute (BHI) applied its STAMP® (State Tax Analysis Modeling Program) model. The RPS requires that each electric utility obtain at least 27 percent of its retail load from renewable energy generation by January 1, 2020. However, such a mandate is inefficient.

The Energy Information Administration (EIA), a division of the U.S. Department of Energy,

provides estimates of renewable electricity costs and capacity factors. This study bases our estimates on EIA projections and compliance reports from Connecticut's Public Utilities Regulatory Authority. Using these sources, BHI then estimated the net benefits, or costs, attributable to the policy. The major findings show:

- The current RPS mandates will raise the cost of electricity by \$249.48 million for the state's electricity consumers in 2020.
- Connecticut's electricity prices are expected to rise by 5.49 percent by 2020, due to the RPS law.

These increased energy prices will likely hurt Connecticut's residents and businesses and, in turn, inflict harm on the state economy. In 2020, the RPS is expected to:

- Lower employment by an expected 2,660 jobs;
- Reduce real disposable income by \$283 million;
- Decrease investment by \$46.4 million.

Additional reliance on expensive peak demand electricity generation sources, and the need for a vast network of power lines, will be large drivers of these cost increases.

1 Paul N. Belval, David T. Doot and Jennifer E. Galiette, Day Pitney LLP, "Governor Malloy Signs Connecticut Clean Energy Bill." August 13, 2013, <http://tinyurl.com/kfkxfyr>

The RPS mandates will force utilities to add renewable electricity capacity to a market that has seen electricity sales fall by 1.5 percent since 2000.² Since electricity demand is flat, the RPS-mandated renewable sources will force utilities to retire existing coal and gas sources.

Unlike wind and solar, coal and gas generators produce electricity on demand (or are “dispatchable”) and provide the bulk of electricity generation under normal conditions – called baseload for the electricity grid. Displacing coal and gas with solar and wind will lower the amount of dispatchable electricity generation under baseload conditions and force utilities to use peak electricity generation sources when wind and solar are not available. In other words, the grid operator will depend on resources that are usually used help supply electricity on those hot summer days (when demand is at its highest) to supply electricity during times of normal electricity demand, when wind and solar sources are not available.

The peak demand electricity generation sources tend to be more expensive, and sometimes burn dirtier fuels such as fuel oil. The state utility is already preparing for such circumstances. The Public Service Enterprise Group (PSEG) of Connecticut recently completed a \$136 million electric generating peaking facility to “operate only during periods of peak power demand” and “improve the reliability of the transmission system, or grid.”³

2 U.S. Energy Information Administration, “Independent Statistics and Analysis, Table 8. Retail Sales, Revenue, and Average Retail Price by Sector, 1990-2012,” <http://www.eia.gov/electricity/state/Connecticut/>

3 Public Service Enterprise Group Power LLC, *New*

Wind power generation will require a vast new network of transmission lines. In 2010, the grid operator ISO New England estimated that for wind power to reach 15.9 percent of electricity production for all of New England, or 8,000 MW of nameplate capacity, would require 4,300 miles of new transmission lines costing between \$17.9 billion and \$23 billion.

Current Sources

According to 2010 data, 74 percent of Connecticut’s Class I mandate was filled from wood or biomass facilities; 12 percent from landfill gas; 9 percent from wind energy; 3 percent from hydropower; and 1 percent from solar power. Nearly 70 percent of the Class II requirement was fulfilled from trash to energy; 15 percent from biomass; and the remaining 15 percent split between hydropower and landfill gas (LFG).⁴

The concentration of biomass in satisfying the RPS mandate correlates well with the fact that 80 percent of the renewable generation originated in the state of Maine and only 3.8 percent originated in Connecticut.⁵ Maine’s forestry industry provides ample fuel for biomass, which produced 25 percent of the state’s electricity production in 2011.⁶

Haven Peaking Project, http://www.pseg.com/family/power/fossil/stations/connecticut/newhaven_peaker.jsp.

4 Ken Nelson, “The State of the CT RPS: Where, What Kind, and How Much,” (October 2012) <http://www5.cbia.com/events/wp-content/uploads/2012/10/Panel-III-130-p-m-Ken-Nelson.pdf>.

5 Ibid.

6 U.S. Energy Information Administration, “Independent Statistics and Analysis: State Profile

The New England Power Pool Generation Information System regulates Connecticut's renewable energy sources to ensure compliance with the current standards. A state is considered to be compliant if it meets the mandated number of renewable energy credits or makes alternative compliance payments.

The RPS mandates force the state utilities to add renewable electricity capacity to a market that has seen electricity sales fall by 1.5 percent since 2000.⁷ By forcing additional electricity generation capacity onto the market with legally guaranteed sales, existing generation resources will be squeezed out of the market and forced to close. A large portion of the renewable generation sources are intermittent—wind and solar require significant conventional backup power sources that are cycled up and down to accommodate the variability in the production of wind and solar power.

Renewables often squeeze out baseload sources, such as coal and gas (that can produce electricity on demand or are “dispatchable”) and provide electricity during times of normal (or baseload) electricity demand. But when this happens during times of highest electricity demand – typically on the hottest days of the summer – or during peak demand – when wind and solar sources are not available – the grid will be forced to rely on peak demand generation sources that only run when the

price of electricity is high enough to cover their marginal costs of fuel.

Peak demand sources tend to be the most expensive generation sources because they can only justify production when the marginal price of electricity is high enough to cover their marginal costs. Peak demand fuel costs are further increased by the soaring price of on-time or spot markets for conventional fuels, such as fuel oil and natural gas, pushing their marginal costs even higher. The switch from baseload demand sources to peak load demand sources drive electricity prices higher.

This scenario is already playing out as the Public Service Enterprise Group (PSEG) of Connecticut recently completed a \$136 million electric generating peaking facility. “As peaking units, these turbines operate only during periods of peak power demand. The facility is helping to improve the reliability of the transmission system, or grid, by quickly providing power when required by the NE-ISO.”⁸ This makes for an expensive cycle.

The cost to transmit new wind generation will also soar as the RPS laws mandate an ever-increasing percentage of electricity generation from renewable sources. Wind power likely will supply a high percentage of the renewable resources to meet the mandates. By nature, wind power plants are placed in windy locations, such as hill tops or in the ocean. These plants will be spread

and Energy Estimates,” <http://www.eia.gov/state/?sid=ME#tabs-1>. (accessed May 13, 2014).

⁷ U.S. Energy Information Administration, Independent Statistics and Analysis, Table 8. Retail Sales, Revenue, and Average Retail Price by Sector, 1990-2012, <http://www.eia.gov/electricity/state/Connecticut/>

⁸ PSEG Power LLC, New Haven Peaking Project, http://www.pseg.com/family/power/fossil/stations/connecticut/newhaven_peaker.jsp.

widely around New England and beyond, and will require an enormous investment in new transmission lines.

In 2010, the grid operator ISO New England estimated that for wind power to reach 15.9 percent of electricity production for all of New England, or 8,000 MW of nameplate capacity, would require over 4,300 miles of new transmission lines costing between \$17.9 billion and \$23 billion. That would equate to between \$2.2 million and \$2.8 million per MW of installed capacity.⁹ The ISO New England report sums up the problem succinctly: “The challenge for the region is that a significant portion of the renewable resource potential is remote from the major population centers, so transmission would be needed to transport these supplies to the electric power grid for delivery to consumers.”¹⁰

Connecticut’s ratepayers are paying \$136 million for a facility that will only operate during times of peak demand. They are also paying for new renewable electricity generation driven by the RPS mandate that is more expensive and unnecessary in an electricity market with excess capacity and falling demand. The new renewable capacity is, in part, forcing coal and gas baseload generation sources out of business, necessitating new investment in new peak demand facilities. This is a recipe for much higher electricity costs, which are beginning to materialize.

9 New England ISO, “New England 2030 Power System Study Report to the New England Governors 2009 Economic Study: Scenario Analysis of Renewable Resource Development,” (February 2010: 21)

<http://tinyurl.com/l4bmy8v>

10 Ibid, 5.

Connecticut ratepayers also spent \$168.1 million in support of RPS generation sources in 2012. Elements Markets estimates that 2013 compliance costs will increase to \$177 million.¹¹ Looking towards the future, DEEP estimates the cost of compliance under the current statute could rise to \$280 million in 2022 from higher RPS mandates, higher Renewable Energy Credit (REC) prices, compliance costs and state renewable energy programs.¹²

The compliance costs could surge even higher as the demand for renewable RECs in New England and the rest of the Northeast outstrips the ability of utilities to secure enough electricity production from eligible sources. Moreover, each new renewable energy project would be placed in a more inefficient location, complicating energy production and transmission issues. Compared to previous projects, these changes will increase costs even further. These costs will not be transparent since ratepayers will never see all of these costs itemized on their electric bills. The vast majority of the costs will be folded into the electricity supply cost and transmission categories.

What effect will these higher costs have on electricity ratepayers and the state economy over the coming years?

The Beacon Hill Institute at Suffolk University (BHI) estimates the costs of the Connecticut RPS law and its impact on the state’s economy. To that end, BHI applied its State Tax Analysis Modeling Program (STAMP®) to estimate the

11 Nelson.

12 DSIRE, “Connecticut.”

Table 1: The Cost of the 27 Percent RPS Mandate on Connecticut

Costs Estimates (2011 \$)	Expected
Total Net Cost in 2020 (\$ million)	250
Total Net Cost 2014-2020 (\$million)	1,587
Electricity Price Increase in 2020 (cents per kWh)	0.72
Percentage Increase (%)	5.49
Economic Indicators	
Total Employment (jobs)	2,660
Investment (\$ million)	46.4
Real Disposable Income (\$ million)	283

economic effects of the state RPS mandates.¹³

Estimates and Results

In light of the wide divergence in the cost estimates available for the different electricity generation technologies, we provide a statistically expected value of Connecticut's RPS mandate that will take place for the indicated variable against the counterfactual assumption that the RPS mandate was not implemented. The Appendix explains the methodology. Table 1 on

the following page displays the cost estimates and economic impact of the current 27 percent RPS mandate in 2020.

The current RPS is expected to impose costs of \$250 million in 2020. As a result, the RPS mandate would increase electricity prices by an expected 0.72 cents per kilowatt-hour (kWh), or by 5.49 percent. The RPS mandate will cost Connecticut electricity customers \$1.587 billion over the period from 2014 to 2020.

The STAMP model simulation indicates that, upon full implementation, the RPS law is likely to hurt Connecticut's economy. The state's ratepayers will face higher electricity prices that will increase their cost of living, which will in turn put

¹³ Detailed information about the STAMP® model can be found at http://www.beaconhill.org/STAMP_Web_Brochure/STAMP_HowSTAMP-works.html.

Table 2: Annual Effects of RPS on Electricity Ratepayers

(2011 \$)	Expected
Cost in 2020	
Residential Ratepayer (\$)	60
Commercial Ratepayer (\$)	655
Industrial Ratepayer (\$)	6,495
Cost over period (2014-2020)	
Commercial Ratepayer (\$)	405
Industrial Ratepayer (\$)	4,195
Industrial Ratepayer (\$)	40,460

downward pressure on households' disposable income. By 2020, the Connecticut economy will shed 2,660 jobs.

The job losses and price increases will reduce real incomes as firms, households and governments spend more of their budgets on electricity and less on other items, such as home goods and services. In 2020, real disposable income will fall by an expected \$283 million. Furthermore, net investment will fall by \$46 million.

Table 2 shows how the RPS mandate is expected to affect the annual electricity bills of households and businesses in Connecticut. In 2020, the RPS is expected to cost families an additional \$60 per year; commercial businesses

\$655 per year; and industrial businesses \$6,495 per year. Over the entire period from 2014 to 2020, the RPS will cost families an additional \$405; commercial businesses \$4,195; and industrial businesses \$40,460.

Sensitivity Analysis

We expand upon our results by undertaking a "Monte Carlo analysis," which sets a distribution of outcomes for each of the main variables, and then simulates the results. This gives a better sense of what outcomes are plausible (rather than merely possible). It also measures the sensitivity of our results to the assumptions about the future values of the input variables.

Table 3: Monte Carlo Analysis

Costs Estimates (2013 \$)	90% Confidence	
Total Net Cost in 2020 (\$ million)	(9.06)	(489.91)
Total Net Cost 2014-2020 (\$ million)	(529.48)	(2,644.36)
Electricity Price Increase in 2020 (cents per kWh)	(0.03)	(1.44)
Percentage Increase (%)	(0.21)	(10.77)
Economic Indicators		
Total Employment (jobs)	(100.00)	(5,230.00)
Investment (\$ million)	(1.70)	(91.00)
Real Disposable Income (\$ million)	(11.00)	(556.00)
Cost in 2020		
Residential Ratepayer (\$)	0.00	120.00
Commercial Ratepayer (\$)	25.00	1,285.00
Industrial Ratepayer (\$)	245.00	12,750.00
Cost over period (2014-2020)		
Residential Ratepayer (\$)	135.00	670.00
Commercial Ratepayer (\$)	1,415.00	6,980.00
Industrial Ratepayer (\$)	13,470.00	67,450.00

For instance, we use the EIA estimates of levelized energy costs (LEC) of different electricity generation technologies through 2030. However, changing circumstances can cause the EIA estimates to change over the years, such as the steep drop in natural gas prices that took place over the past few years.

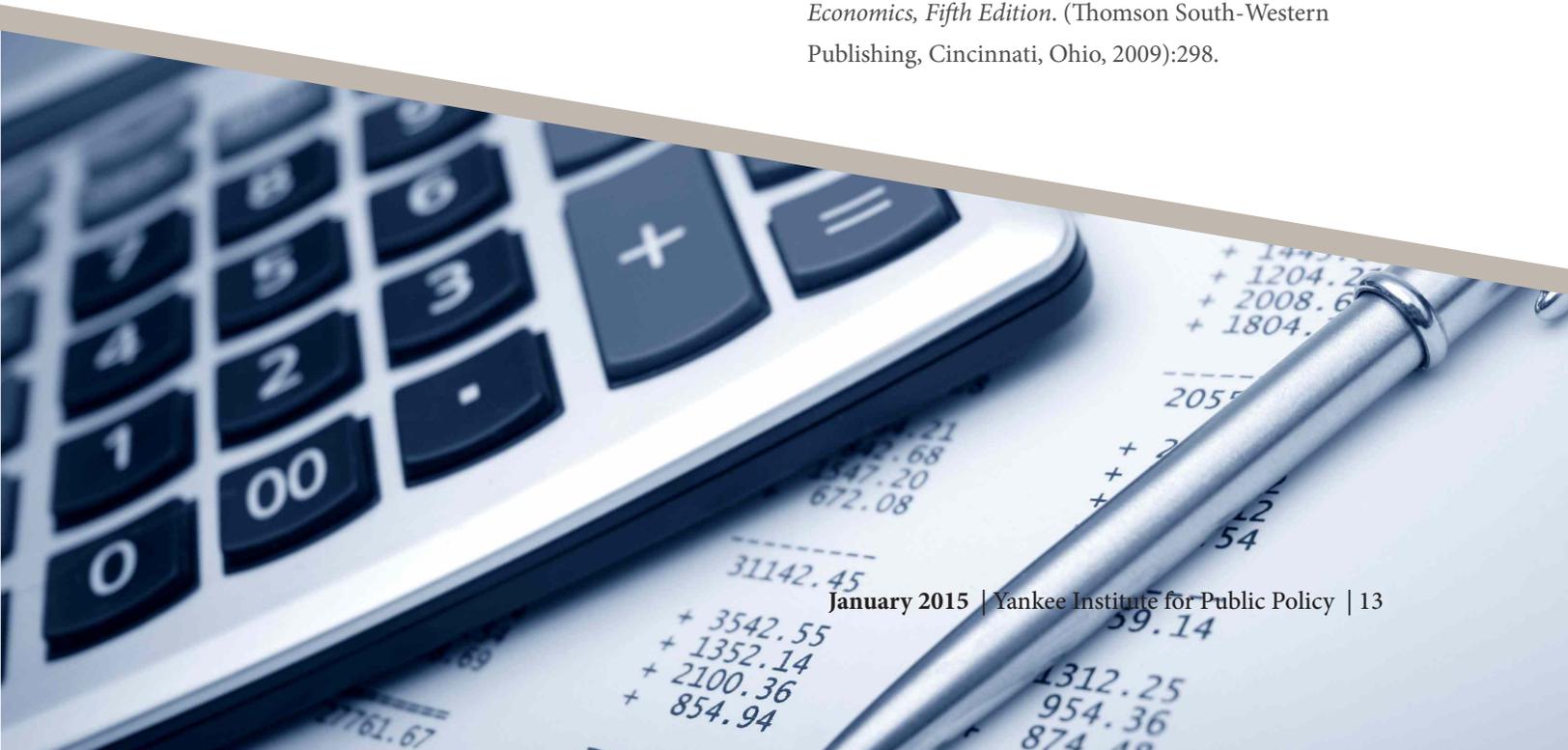
We drew 10,000 random samples from the distributions, and computed the variables of interest (rates of return, net present value, etc.). This allowed us to compute a distribution of outcomes, which shows the net present value of benefits minus costs, for the electricity price analysis. The full set of assumptions is shown in the Appendix.

The most important feature of this risk analysis is that it allows us to compute confidence intervals for our target variables. These are shown in Table 3. Thus the 90 percent confidence interval for the net cost of electricity – in other words, we are 90 percent confident that the true result lies inside this band. The 90-percent confidence interval is a commonly accepted standard for making statistical

inferences.¹⁴ Thus our conclusion that the RPS mandate is economically harmful is robust. The first Column in Table 3 shows that the net costs in 2020 will fall between \$9 million and \$490 million. The costs translate into average electricity price increases of .03 cents per kWh and 1.44 cents per kWh, or a 0.21 percent and 10.77 percent rate increase. Thus we are 90 percent confident that the RPS mandate will raise costs for electricity customers. The lower half of Table 3 translates these costs into increases in electric bills; and residential, commercial and industrial ratepayers would all see their bills increase, within our 90 percent confidence intervals.

The net costs translate into net employment losses of 100 jobs to 5,230 jobs, and disposable income losses of \$11 million to \$556 million. Investment losses will tally from \$1.7 million to \$91 million.

14 David R. Anderson, Dennis J. Sweeney and Thomas A. Williams. *The Essentials of Statistics for Business and Economics, Fifth Edition*. (Thomson South-Western Publishing, Cincinnati, Ohio, 2009):298.



CONCLUSION

Lost among the claims of increased investment and jobs in the ‘green energy sector’ is a discussion of the opportunity costs of RPS policies.

By mandating that electricity be produced by more expensive sources, ratepayers in the state will experience higher electricity prices. This means that every business and manufacturer in the state will have higher costs, leading to less investment in both capital and labor. Moreover, every household will have less money to spend on other necessities and desires, from groceries to entertainment.

Proponents of the RPS law are correct – there will be more investment and jobs in the ‘green energy sector’ but rarely, if ever, do they mention the loss of jobs and investment in every other sector in the state due to higher electricity prices. The movement of publicly directed investment is seen; the costs and forgone opportunities that would have been created with these resources are not considered.

The promise of local jobs cannot be met. Only 3.8 percent of the renewable generation used to satisfy the RPS mandate has been generated in Connecticut, meaning the jobs and investment are being created elsewhere, primarily in Maine where 80 percent of the RECs originate. The methodology in this paper takes all sectors into account, resulting

in a very likely outcome of less jobs and lower investment for Connecticut.

The state lacks the necessary transmission infrastructure needed to make the RPS effective. The high cost associated with infrastructure—which must be borne by ratepayers—ultimately diminishes the promise of renewable energy over time.¹⁵

The RPS has and will continue to generate economic benefits for a small group of favored industries. But all of Connecticut’s electricity customers will pay higher rates, diverting resources away from investment and spending on other sectors. The increase in electricity prices will harm the competitiveness of the state’s businesses, particularly in the energy-intensive manufacturing industries. Firms with high electricity usage will likely move their production, and emissions, out of Connecticut to locations with lower electricity prices. Therefore the RPS policy will not reduce global emissions, but rather send jobs and capital investment outside the state.

15 L. Alagappan, R.Orans and K.Wooa, “What drives renewable energy development?” *Energy Policy* 39 (2011): 5099–5104.

APPENDIX

The Connecticut RPS sorts mandated energy sources into Class I, Class II and Class III. Class I energy resources include solar power, wind power, fuel cells, methane gas from landfills, ocean thermal power, tidal power, low emission advanced renewable energy conversion technologies, hydropower or energy from a biomass facility. Hydropower plants must not exceed five megawatts, or cause a change in river flow, and are only eligible if the facility began operation after July 1, 2003. Biomass facilities must have an average emission rate of less than or equal to 0.75 pounds of nitrogen oxides per million BTU of heat input for the previous calendar quarter. Utility customer-distributed energy projects using Class I technologies also qualify. Existing renewable energy resources continue to qualify for Class I renewable energy.¹⁶

Class II includes trash-to-energy facilities, certain biomass facilities not included in Class I, and certain older run-of-the-river hydropower facilities.

Class III resources include customer-sited CHP systems, with a minimum operating efficiency of 50 percent, installed at commercial facilities in Connecticut on or after January 1, 2006; electricity savings from conservation and

¹⁶ Database of State Incentives for Renewables & Efficiency (DSIRE) "Connecticut: Incentives/Policies for Renewables & Efficiency," August 13, 2013, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CT04R Last DSIRE Review: 07/19/2013.

demand management programs beginning on or after January 2006; and systems that recover waste heat or pressure from commercial processes installed on or after April 1, 2007.¹⁷

Utilities must obtain Renewable Energy Credits (RECs) for each megawatt-hour (MWh) of electricity generated by renewable sources. RECs from renewable energy produced in New York, Pennsylvania, New Jersey, Maryland and Delaware are eligible as long as they were not used to satisfy another state renewable mandate or goal. Utilities that fail to comply with the RPS mandate must make an Alternative Compliance Payment (ACP) of \$55 per MWh of Class I and II REC shortages and \$31 per MWh for Class III.¹⁸

Senate Bill No. 1138, "An Act Concerning Connecticut's Clean Energy Goals," modified Connecticut's Renewable Portfolio Standard by expanding the modifying the classifications of acceptable renewable resources. Class I now includes geothermal, anaerobic digestion, or other biogas derived from biological sources, and thermal electric direct energy conversion.

¹⁷ Ibid.

¹⁸ Kevin M. DelGobbo, John W. Betkoski, III and Anthony J. Palermino, "Annual Review of Connecticut Electric Suppliers' and Electric Distribution Companies' Compliance with Connecticut's Renewable Energy Portfolio Standards in the Year 2008," January 26, 2011, Docket No. 09-10-09 <http://www.dpuc.state.ct.us/dockhist.nsf/8e6fc37a54110e3e852576190052b64d/516c94bb-f8105147852578b70061cac7>

In addition, the Act increases the eligibility of hydroelectric facilities from a capacity from 5 megawatts per hour (MWhs) to 30 MWhs, and eliminates the requirement that facilities do not change the river flow.¹⁹

The Act's most notable change allows large-scale hydropower from other states and even Canada to qualify, but only under all of the following stipulations:

- The facilities must have become operational on or after January 1, 2003 and only displace a portion of the RPS mandate that has been satisfied by ACPs;
- existing renewable sources exist are insufficient to satisfy the RPS mandate; and
- Other providers fail to fill the renewable generation gap in response to a request for proposals.

If these triggering mechanisms exist, then beginning in 2016 large-scale hydroelectric power may be used to fulfill 1 percentage point of the RPS. In subsequent years, hydroelectric may be used to fulfill up to five percent of the RPS mandate.²⁰

The Act also provides additional incentives to redistribute the mix of new renewable technologies away from biomass and toward low- or zero-emissions technologies. It calls on the Department of Energy and Environment Protections (DEEP) to gradually reduce the value of biomass RECs. Public Act 1180 of 2011 mandated utilities to enter into 15-year

contracts for specified dollar values of zero emission technologies (ZRECs) and low emission technologies (LRECs). Specifically, utilities must enter into \$4 million in LREC contracts in 2012 and an additional \$4 million in the subsequent years. Utilities must spend \$8 million in the first year and increase it by \$8 million per year in the subsequent four years. The bill also caps spending on ZRECs and LRECs at \$350 and \$200 each respectively, or \$0.35 per kWh and \$0.20 per kWh, compared to the current residential electricity price of \$0.1811 per kWh. Senate Bill No. 1138 directs revenue from ACP payments to offset the cost of the LRECs and ZRECs.²¹

To provide a statistically significant confidence interval for net cost calculations for state level Renewable Energy Standards (RPS), we used a Monte Carlo simulation. A Monte Carlo simulation is generated by repeated random sampling from a distribution to obtain statistically significant results. This allows for the determination of the range and probability of the cost and percent change outcomes of a policy based on distributions placed on key, specific variables, as discussed in this appendix. Oracle's Crystal Ball software provided an easy-to-use and established methodology for generating the results.²²

Determining the Levelized Energy Cost Distribution

Determining the mean value and standard deviation of electricity is the first step in

²¹ DSIRE, "Connecticut."

²² Oracle Crystal Ball, Overview, <http://www.oracle.com/us/products/applications/crystalball/overview/index>.

¹⁹ Belval, Doot, et. al.

²⁰ Ibid.

building a Monte Carlo simulation. For this we relied upon the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO) Levelized Energy Costs (LEC). The 2013 AEO explains:

Levelized cost is often cited as a convenient summary measure of the overall competitiveness of different generating technologies. It represents the per-kilowatt-hour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle. Key inputs to calculating levelized costs include overnight capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate for each plant type.²³

Using this comprehensive and widely accepted methodology, we utilized the detailed regional data set, allowing us to go into extensive depth. We defined LEC for every year between 2014 and 2030, across 22 different regions for 17 different types of electricity generating technologies. For example, the mean cost to produce a megawatt-hour (MWh) of power from wind power, in the Northeast Power Coordinating Council/ New England region, for a plant coming online in 2020 was calculated, and represented as Mean(Wind, NPCC/NE, 2020). This level of detail enabled the modeling of state specific RPS with varying requirements year to year.

23 U.S. Energy Information Administration, Annual Energy Outlook 2013, "Levelized Cost of New Generation Resources," (January 28, 2013) http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.

Two different data sets were examined to calculate the variables required for the Monte Carlo simulation. The first was the LEC as modeled by the National Energy Modeling System from the AEO2008. The second was the 'No Sunset' version of the same data set from the AEO2013. The No Sunset version was preferable for our analysis because it assumes that expiring tax credits would be extended, which we believe is the most likely scenario.²⁴ Additionally, since the vast majority of expiring tax credits are for renewable generation sources, such as wind, solar and biomass, it makes the projections much more conservative.

Before calculating the mean and standard deviation for each data point, some minor adjustments to the AEO2008 data were required to match with the AEO2013 data. The first step was to grow the AEO2008 numbers, originally in 2006 US dollars, so that they were in 2011 US dollars like the AEO2013 data. To do this, the annual U.S. Consumer Price Index for Energy was employed. The index was at 196.9 in 2006 and 243.909 in 2011, resulting in the AEO2008 prices being multiplied by approximately 1.24.²⁵ Additionally, the 13 regions from AEO2008 had to be matched up with the 22 regions of AEO2013. For some this was a simple conversion, such as the Florida Reliability Coordinating Council from AEO2008, which did not change in the AEO2013. But others were split up into 2 or 3 different regions, for example region 1 in the AEO2008 was split up such that

24 Energy Information Administration, "Issues in Focus," April 2013, http://www.eia.gov/forecasts/aeo/IF_all.cfm

25 U.S. Bureau of Labor Statistics, Consumer Price Index, <http://www.bls.gov/cpi/>.

it became region 10, 11 and half of 15 (the other half of 15 came from region 9 in AOE2008).

Table 4 below shows our matching.

Table 4: AEO2008 to AEP2013 Region Matching

AEO 2008 Region*	AEO 2013 Region*
1	10, 11, (½)15,
2	1
3	6, 7, 9
4	3, (1/3) 4, 13
5	(2/3) 4
6	8
7	5
8	2
9	12, 14, (½)15, 16
10	17, 18
11	21
12	19, 22
13	20
* Numbers based on Electricity Market Module Regions from the respective AEOs.	

With the data in the same year and regions, we compared the TOTAL from AEO2008 to the TOTAL from AEO2013. The AEO2013 added in additional information in the form of ITC/PTC which stands for ‘Investment Tax Credit/Production Tax Credit’, a negative cost to the producer of the energy. This was added back into the calculations after, as it did not exist in

the AEO2008, allowing an ‘apples-to-apples’ comparison. We calculated the mean for each of these data points. This was accomplished by comparing the projections of LEC from the AEO2008 to those made in the most recent AEO2013.²⁶ This represents what we believe best corresponds to the expected value around which a normal distribution of possible outcomes is centered.

To calculate each individual standard deviation – for example, Standard Deviation (Wind, 5, 2020) – we calculated the sample standard deviation between the AEO2008 and AEO2013 points. With these two calculations completed, the result allowed us to create projections of normal distributions for the LEC of various energy production techniques.

The only exception to this method was for solar photovoltaic production. The change in forecasted prices from AEO2008 to AEO2013 was very large, mainly due to assumptions made at the time. During the forecasting of the AEO2008 raw material, including rare earth metals, prices were at or near all-time highs. During the AEO2013, solar companies were going out of business as government incentives, competition from China, and increased investment in raw material mining drove down the costs of solar. For this reason we set the standard deviation equal to one quarter of the distance between the two projections. In essence this means that 95 percent of the selections by Crystal Ball will fall between the two projections.

²⁶ Energy Information Administration, Forecasts, <http://www.eia.gov/forecasts/aeo/> and <http://www.eia.gov/oiaf/archive/aeo08/index.html>.

Determining Future Electricity Consumption
As with predicting the LEC of electricity production techniques, predicting future electricity consumption is difficult, yet essential to determining the effects of RPS policies. For this reason we again calculated a normal distribution for electricity consumption for the state, by year. We reviewed the last 22 years of State Gross Domestic Product (SGDP) and electricity consumption by state and determined that there is a strong correlation between electricity consumption and SGDP.²⁷ To determine the strength and interaction we produced the following simple regression.

$$\begin{aligned} \text{Log(Electricity Consumption)} &= \beta_0 + \beta_1 \\ &\text{Log(SGDP)} \\ \text{Or} \\ \text{Log(Electricity Consumption)} &= 14.24013 \\ &+ 0.302208 \text{Log(SGDP)} \end{aligned}$$

Table 5 below displays some of the relevant regression statistics. The simple regression fits the data quite well, with 94 percent of the variance Log(Electricity Consumption) explained by changes in the independent variable. The test statistic associated with Log(SGDP) is individually significant.

Table 5: Regression Statistics

Adjusted R2	0.9415
Prob>T	0
Standard Error Log(SGDP)	0.0147355
Number of Observations	22

27 See BLS and EIA: <http://www.bea.gov/regional/index.htm> and <http://www.eia.gov/electricity/data.cfm>.

Next, we forecasted SGDP using an ARIMA (Autoregressive, Iterative, Moving Average) model which estimates a regression equation that extrapolates from historical data to predict the future. We used the Log(SGDP) to transform the growing series into a stable series and included Log(US GDP) as an independent variable.

In estimating the regressions, we paid particular attention to the structure of the errors, in order to pick up the effects of seasonal, quarterly and monthly variations in tax collections. This was done by estimating the equations with autoregressive (AR) and moving average (MA) components. The number and nature of the AR and MA lags were determined initially by examining the autocorrelation and partial correlation coefficients in the correlogram, and then fine-tuning after examining the structure of the equation residuals. For Connecticut, the SGDP series conformed to an AR(1) and MA(1) in addition to a constant term.

Using the combination of the regression equation and the calculated Standard Error we constructed a normal distribution of electricity sales for each year in our prediction range.

Additional Data

With the distributions of LEC and electricity consumption defined, we looked to other data points that required estimates – the first of which was baseline sales of renewable energy. That is, the level of renewable generation that would have come online without taking into consideration the policy under review. The difference between this baseline and the policy requirement is the amount of renewable energy that has to come online due to the policy itself. The baseline level

of renewables was set equal to the total amount of renewable generation in 2003, as the policy was established in Connecticut in June of 2004.²⁸ To err on the conservative side, we included all renewable energy, even though hydroelectric facilities larger than 30MW were excluded. This amount was then grown annually according to the projected growth of renewables in the region per the AEO2003.²⁹

28 Energy Information Administration, “Electric Power Industry Generation by Primary Energy Source, 1994, 1998, and 2003,” <http://www.eia.gov/electricity/state/>.

29 Energy Information Administration, “Supplement Tables to the Annual Energy Outlook 2003, Table 82. Renewable Energy Generation by Fuel Northeast Power Coordinating Council / New England” (July 21, 2003) http://www.eia.gov/oiaf/archive/aeo03/supplement/suptab_82.htm.

The second data point calculated was the distribution of new renewable production that came online due to the policy. The share of new renewable generation was calculated based on information from the 2013 Connecticut Department of Energy and Environmental Protection’s RPS Report.³⁰ This report supplied two figures, one for both Class I resource mix and Class II resource mix for 2010, the most recent year available. This was then grown using EIA projections for generation growth by region.

The results of our baseline calculations, not using Monte Carlo simulations, are presented in Table 6.

30 The Connecticut Department of Energy and Environmental Protection, “Restructuring Connecticut’s Renewable Portfolio Standard, Final. April 26, 2013.

Table 6: Projected Electricity Sales, Renewable Sales

Year	Projected Electricity Sales MWhs (000s)	Projected Renewable MWhs (000s)	RPS Requirement MWhs (000s)	Difference MWhs (000s)
2014	8,205.11	147.56	697.43	549.87
2015	8,331.41	153.01	833.14	680.13
2016	8,452.41	158.61	972.03	813.42
2017	8,560.07	166.84	1,112.81	945.97
2018	8,654.13	171.03	1,254.85	1,083.81
2019	8,742.25	176.21	1,398.76	1,222.55
2020	8,828.63	182.22	1,412.58	1,230.36

Some types of renewable generation, such as wind and solar power, are considered intermittent power sources.³¹ That is, output varies greatly over time, depending on numerous difficult-to-predict factors. If the wind blows too slowly, too fast, or a cloud passes over a solar array, the output supplied changes minute to minute while demand will not mirror these changes. For this reason, conventional types of energy need to be kept as ‘spinning reserves.’ That is, they need to be able to ramp up, or down, output at a moment’s notice. The effect of this is that for every one MWh of intermittent renewable power introduced, the offset is not one MWh of conventional power, but some amount less. To account for this, we used a policy study from the Reason Foundation that noted:

Gross et al. show that the approximate range of additional reserve requirements is 0.1 percent of total grid capacity for each percent of wind penetration for wind penetrations below 20 percent, raising to 0.3 percent of total grid capacity for each percent of wind penetration above 20 percent.³²

31 Patrick A. Narbel, “Rethinking how to support intermittent renewables.” Dept. of Business and Management Science, Norwegian School of Economics (April 2014), http://d.repec.org/n?u=RePEc:hhs:nhh:fms:2014_017&r=ene.

32 William J. Korchinski and Julian Morris, “The Limits of Wind Power,” Reason Foundation (October 4, 2012) <http://reason.org/studies/show/the-limits-of-wind-power>.

We reviewed the original Gross article, which compiled numerous papers on the topic, and found the Reason Foundation calculations to be very conservative. We attempted to contact the authors to determine their methodology, but were unable to. The result was using their numbers, again to err on the conservative side, with less spinning reserves factored in, being more favorable to renewable sources.

Finally, a calculation of the distribution of conventional energy resources – that would be crowded out due to a higher share of renewables – is needed. In Connecticut, 99.8 percent of nonrenewable energy comes from natural gas, with the remainder from petroleum.³³ For this reason we assume that all spinning reserves, and crowded out electricity, comes from natural gas.

Using the above-compiled data, we were able to calculate the amount of new renewables that will likely come online due to the policy, as well as the likely conventional energy displaced. Combining this information with the estimated LEC of electricity in each of the studied years yields the total cost of the policy. The total cost of the policy divided by the amount of electricity consumed yields a percent cost of the policy.

Ratepayer Effects

To calculate the effect of the policy on electricity ratepayers we used EIA data on the average monthly electricity consumption by type of customer: residential, commercial and

33 U.S. Energy Information Administration, Connecticut Electricity Profile, as in “Table 5. Electric Power Industry Generation by Primary Energy Source, 1990 through 2010.” <http://www.eia.gov/electricity/state/rhodeisland/>.

industrial.³⁴ The monthly figures were multiplied by 12 to compute an annual figure. We inflated the 2011 figures for each year using the regional EIA projections of electricity sales.³⁵

We calculated an annual per-kWh increase in electricity cost by dividing the total cost increase — calculated in the section above — by the total electricity sales for each year. We multiplied the per-kWh increase in electricity costs by the annual kWh consumption for each type of ratepayer for each year. For example, we expect the average residential ratepayer to consume 1,011 kWh of electricity in 2020 and the expected percent rise in electricity to be by 0.22 cents per kWh in the same year. Therefore, we expect residential ratepayers to pay an additional \$233.91 in 2015.

Modeling the Policy using STAMP

We simulated these changes in the STAMP model as a percentage price increase on electricity to measure the dynamic effects on the state economy. The model provides estimates of the proposal's impact on employment, wages and income. Each estimate represents the change that would take place in the indicated variable against a “baseline” assumption of the value that variable for a specified year in the absence of the RPS policy.

34 Energy Information Administration, “Electric Sales, Revenue, and Average Price,” at http://www.eia.gov/electricity/sales_revenue_price/.

35 Energy Information Administration, “Electric Power Projections for EMM Regions,” <http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO-2013ER&subject=0-AEO2013ER&table=62-AEO-2013ER®ion=3-5&cases=early2013-d102312a>.

Because the policy requires households and firms to use more expensive renewable power than they otherwise would have under a baseline scenario, the cost of goods and services will increase under the policy. These costs would typically manifest through higher utility bills for all sectors of the economy. For this reason, we selected the sales tax as the most fitting way to assess the impact of the policy. Standard economic theory shows that a price increase of a good or service leads to a decrease in overall consumption, and consequently a decrease in the production of that good or service. As producer output falls, the decrease in production results in a lower demand for capital and labor.

BHI utilized its STAMP® (State Tax Analysis Modeling Program) model to identify the economic effects and understand how they operate through a state's economy. STAMP is a five-year dynamic CGE (computable general equilibrium) model that has been programmed to simulate changes in taxes, costs (general and sector-specific) and other economic inputs. As such, it provides a mathematical description of the economic relationships among producers, households, governments and the rest of the world. It is general in the sense that it takes all the important markets, such as the capital and labor markets, and flows into account. It is an equilibrium model because it assumes that demand equals supply in every market (goods and services, labor and capital). This equilibrium is achieved by allowing prices to adjust within the model. It is computable because it can be used to generate numeric solutions to concrete policy and tax changes.³⁶

36 For a clear introduction to CGE tax models, see John B. Shoven and John Whalley, “Applied

In order to estimate the economic effects of the policy we used a compilation of six STAMP models to garner the average effects across various state economies: New York, North Carolina, Washington, Kansas, Indiana and Pennsylvania. These models represent a wide variety in terms of geographic dispersion (Northeast, Southeast, Midwest, the Plains and West), economic structure (industrial, high-tech, service and agricultural), and electricity sector makeup.

Using three different utility price increases – 1 percent, 4.5 percent and 5.25 percent – we simulated each of the six STAMP models to determine what outcome these utility price increases would have on each of the six states’ economy. We then averaged the percent changes together to determine the average effect of the three utility increases. Table 6 displays these elasticities, which were then applied to the calculated percent change in electricity costs for the state as discussed above.

General-Equilibrium Models of Taxation and International Trade: An Introduction and Survey,” *Journal of Economic Literature* 22 (September, 1984): 1008. Shoven and Whalley have also written a useful book on the practice of CGE modeling entitled *Applying General Equilibrium* (Cambridge: Cambridge University Press, 1992).

Table 7: Elasticities for the Economic Variables

Economic Variable	Elasticity
Employment	-0.022
Investment	-0.018
Disposable Income	-0.022

We applied the elasticities to percentage increase in electricity price and then applied the result to state level economic variables to determine the effect of the policy. These variables were gathered from the Bureau of Economic Analysis Regional and National Economic Accounts as well as the Bureau of Labor Statistics Current Employment Statistics.³⁷

37 For employment, see the following: U.S. Bureau of Labor Statistics, “State and Metro Area Employment, Hours, & Earnings,” <http://bls.gov/sae/>. Private, government and total payroll employment figures for Michigan were used. For investment, see “National Income and Product Account Tables,” U.S. Bureau of Economic Analysis, <http://www.bea.gov/itable/>. See also BEA, “Gross Domestic Product by State,” <http://www.bea.gov/regional/>. We took the state’s share of national GDP as a proxy to estimate investment at the state level. For state disposable personal income, see “State Disposable Personal Income Summary,” BEA, <http://www.bea.gov/regional/>.

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