The Beacon Hill Institute

The Economic Impact of New Hampshire's Renewable Portfolio Standard

THE BEACON HILL INSTITUTE AT SUFFOLK UNIVERSITY
8 Ashburton Place Boston, MA 02108
Tel: 617-573-8750, Fax: 617-994-4279
Email: bhi@beaconhill.org, Web: www.beaconhill.org

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Executive Summary

To estimate the economic effects of the New Hampshire Renewable Portfolio Standards (RPS), the Beacon Hill Institute at Suffolk University (BHI) applied its STAMP® (State Tax Analysis Modeling Program) model. The RPS requires that each electric utility obtain at least 24.8 percent of its retail load from various renewable energy generation sources by 2025. However, such a mandate is inefficient and seeks to pick winners in the local energy market.

The Energy Information Administration (EIA), a division of the U.S. Department of Energy, estimates renewable electricity costs and capacity factors. This study bases our estimates on EIA projections and compliance reports from New Hampshire's Public Utilities Commission (PUC). Using these sources, BHI then estimated the net benefits, or net costs, attributable to the policy. The major findings show:

- The current RPS mandates will raise the cost of electricity by $70 million for the state's electricity consumers in 2025; and
- New Hampshire's electricity prices are expected to rise by 3.7 percent by 2025, due to the RPS law.

These increased energy prices will likely hurt New Hampshire's residents and businesses and, in turn, inflict harm on the state economy. In 2025, the RPS is expected to:

- Lower employment by an expected 720 jobs;
- Reduce real disposable income by $70 million;
- Decrease investment by $10 million; and
- Increase the average household electricity bill by $40 per year; commercial businesses by an expected $230 per year; and industrial businesses by an expected $3,655 per year.

The RPS mandates will force utilities to add renewable electricity capacity to a market that has been flat since 2003.[1] 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 what is known as dispatchable generation). Combined, these forms 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

[1] 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/newhampshire/.

usually used to 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.

Additionally, the way the law was written, the state in 2025 will require 9.5 percent of electricity to come from sources which began generation prior to 2006, or to pay a compliance fee. Under a baseline scenario, most of this will be met with compliance payments, meaning that this share of the policy will contribute nothing to requiring cleaner sources of electricity, but will increase the cost of electricity that every individual and company will consume.

Introduction

Renewable energy refers to power that comes from sources that can be replaced in a timescale relative to the human life time. Coal, natural gas, large hydro and oil are not considered qualifying sources, while eligible renewable technologies range from wood or biomass, to solar- and wind-generated electricity. When used to replace conventional fossil fuels, such as coal or natural gas, renewables can provide the benefit of producing electricity with less of the negative byproduct of emissions. But with every benefit comes a cost. The reason that laws are used to encourage renewables is that they are more expensive than conventional forms of electricity generation, so would not be utilized as often without a legal requirement, and results in a higher prices of electricity for consumers.[2]

Established in May 2007, the New Hampshire Renewable Portfolio Standard (RPS) legislation is, at first glance, quite ambitious. When former governor John Lynch signed the law, the RPS mandated that 24.8 percent of electricity sold to customers must come from renewable sources by 2025. The Beacon Hill Institute at Suffolk University (BHI) modeled the net effects of the policy on electricity prices – as well as a variety of economic indicators – to determine the net cost of the policy, in addition to the resulting benefits of reduced emissions.

A closer examination of the RPS is required to determine the actual costs and benefits of the policy. The law defines four different 'classes' of renewable energy requirements. Class I mandates new renewables that began producing electricity after the January 1, 2006. These renewables are defined as the majority of what are typically considered renewables, including wind, solar, geothermal and biomass. Class I renewables do not include new hydroelectricity or any forms of nuclear energy. In 2015, six percent of electricity must come from these sources, of which at least 10 percent (0.6 percent of total) must come from energy sources such as solar thermal and biomass thermal.[3] New Hampshire is the first state in the United States to require thermal energy in its production mix.

Class II renewables can only be filled by eligible solar technologies coming into operation after January 1, 2006. This class requires that 0.3 percent of electricity come from solar in 2015, and remains unchanged through 2025 and after. The Class III renewables can only be met by eligible biomass plants that started producing electricity prior to January 1, 2006. Eight percent of electricity must come from this preexisting source by 2015 and continue at that level indefinitely. Lastly, Class IV renewables can only be met by preexisting small scale hydroelectricity plants. This requirement started at 0.5 percent in 2008, increasing to 1.5 percent by 2015 and thereafter.

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[2] Honbo Wang, "Do Mandatory U.S. State Renewable Portfolio Standards Increase Electricity Prices?" Munich Personal RePEc Archive Paper 549165, (October 2014), http://mpra.ub.uni-muenchen.de/59165/.
[3] NH Public Utilities Commission (NHPUC), "Electric Renewable Portfolio Standard," http://www.puc.state.nh.us/sustainable%20Energy/Renewable_Portfolio_Standard_Program.htm.

Renewable Energy Credits (RECs) are used as a measuring stick to confirm that these goals are met. A REC is formed by producing a certified megawatt hour (MWh) of electricity by a specific renewable source. A certified REC can then be retired with the Public Utilities Commission to satisfy a utilities requirement, or can be sold to a utility that needs more RECs to be compliant with the law. Additionally, if a utility does not retire a REC it can be used in within the next two years to satisfy a maximum of 30 percent of that year's requirement.

Built into the policy is also a cost containment measure. Should a utility be unable, or unwilling, to meet its annual REC requirement, it can pay an Alternative Compliance Payment (ACP). This payment was set in the original law, and is changed each year to reflect changes due to inflation.[4] In 2013, these payments ranged from $25 per MWh for the thermal carve-out up to $55 for Class I and Class II RECs. According to law, all ACPs are deposited into a Renewable Energy Fund (REF) and "shall be used by the commission to support thermal and electrical renewable energy initiatives."[5]

While legally required to use the REF in support of renewable energy, state politicians have shown that they will ignore the law's intention. In 2010, when New Hampshire was suffering from a budget deficit, the state took $3.1 million from the Greenhouse Gas Emission Reduction Fund (GGERF).[6] This fund was set up in the same manner as the Renewable Energy Fund, although it was funded by payments related the Regional Greenhouse Gas Initiative, a policy to set a cap on emissions by utilities. When created, the GGERF was intended to support energy efficiency, conservation and demand response programs.[7]

In 2013 – again looking for ways to fill the budget shortfall – lawmakers in New Hampshire spared the GGERF and withdrew $16.1 million from the REF.[8] This amount is more than double the prior year's total budget for the fund. The compliance payments were the second-highest on record in 2013 at $17.2 million, and are more than 6.5 times the total amount paid in 2010, the first year that ACPs were available for all four classes.[9] Despite this, the ACP per MWh for Class I, II and IV was lower than the amount in 2010. The total ACP is likely to keep increasing as the demand for renewable RECs in the New England and the rest of the Northeast outstrips the ability of utilities to secure enough electricity production from eligible sources. It can be assumed that each time a new wind or solar plant is installed, it is placed in the most favorable location available, therefore the next renewable energy project would be placed in a less efficient location, complicating energy production and transmission issues.

[4] New Hampshire Legislature, Title XXXIV, Public Utilities, Chapter 362-F, Electric Renewable Portfolio Standard, Section F:10. http://www.gencourt.state.nh.us/rsa/html/XXXIV/362-F/362-F-10.htm.

[5] Ibid.

[6] NH Public Utilities Commission, "2012 RGGI Annual Report to the NH Legislature," https://www.puc.nh.gov/Sustainable%20Energy/GHGERF/RGGI%20Annual%20Reports/2012%20RGGI%20Annual%20Report%20to%20NH%20Legislature%20110112.pdf.

[7] NH Public Utilities Commission, "Greenhouse Gas Emission Reduction Fund," https://www.puc.nh.gov/Sustainable%20Energy/GHGERF.htm.

[8] New Hampshire Union Leader. "Legislature's use of Renewable Energy Fund called 'bait and switch," (June 29, 2013), http://www.unionleader.com/article/20130630/NEWS05/130639982.

[9] New Hampshire Public Utilities Commission, *Annual Compliance Reports 2014*, http://www.puc.state.nh.us/sustainable%20Energy/Renewable_Portfolio_Standard_Program.htm.

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 cost itemized on their electric bills. The vast majority of the costs will be folded into the electricity supply cost and transmission categories.

Class III RECs are rarely available to New Hampshire utilities, as they can be sold in surrounding states for more than the ACP. So utilities seeking to meet their requirement end up paying the $31.93 ACP, while the Class III RECs generated in NH are sold to other states at a higher level.[10] Due to this scarcity, a hearing by the PUC resulted in a reduction to the Class III requirement between 2012 and 2014, before it is scheduled to increase to eight percent in 2015. During these reduced years, when the smallest number of RECs were required, close to 100 percent of the requirement was met with ACP.

If the purpose of the RPS was to increase the use of renewable resources to produce electricity at the lowest cost to ratepayers, then none of the different Class requirements would exist. Mandating that a percentage of electricity must emanate from renewable sources, and then allowing the most cost-efficient methods to fulfill this would achieve this goal. But in reviewing the Class carve-outs, it becomes obvious that part of the purpose is industrial policy. By mandating that specific types of generation techniques be used – such as thermal or solar – the net cost of the policy to ratepayers is increased, which redounds to the benefit of those mandated industries.

This is part of the reason that New England Wood Pellet is credited with having the thermal carve-out inserted in the RPS.[11] By advocating for a policy that requires others to buy thermal energy, not only is money transferred from ratepayers to those supplying thermal energy; it also creates an incentive to demand more of the product. This is not the market at work, but rather the heavy hand of state government directing resources to less efficient uses.

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. The use of coal, according to most policy objectives, would eventually be severely limited or eliminated.[12] Replacing fossil fuels like coal and natural gas in the interim and long-term would be renewables such as wind and solar. However, a 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. However, if renewables squeeze out baseload sources, then during times of

[10] More details on this are available in our Appendix.

[11] Jennifer Runyon, "New Hampshire Sets Thermal Renewable Energy Carve Out," *Renewable Energy World*, June 26, 2012, http://www.renewableenergyworld.com/rea/news/article/2012/06/hew-hampshire-sets-thermal-renewable-energy-carve-out.

[12] Bob Sussman, "Debating the EPA's Clean Power Plan Proposal — EPA's State Goals for Reducing Carbon Pollution from Power Plants: A Thoughtful and Fair Solution to a Complex Problem," Planet Policy Blog, Brookings Institution, (July 29, 2014), http://www.brookings.edu/blogs/planetpolicy/posts/2014/07/29-epa-state-goals-carbon-pollution-sussman.

the highest electricity demand, 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 will drive electricity prices higher.

In 2010, grid operator ISO New England estimated that for wind power to reach the goal of 15.9 percent of electricity production for all of New England (8,000 MW of name plate capacity), it must spend between $17.9 billion and $23 billion. That would equate to between $2.2 million and $2.8 million per MW of installed capacity.[13] The ISO New England report summed 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."[14] This is a recipe for much higher electricity costs, which are beginning to materialize.

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 New Hampshire 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 economic effects of the state RPS mandates.[15] The STAMP model simulates the New Hampshire economy as it responds to policy changes such as the RPS mandate.

Estimates and Results

In light of the wide divergence in the costs estimates available for the different electricity generation technologies, we provide a statistically expected value of New Hampshire'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 24.8 percent RPS mandate in 2025.

The current RPS is expected to impose costs of $70 million in 2025. As a result, the RPS mandate would increase electricity prices by an expected 0.52 cents per kilowatt-hour (kWh),

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[13] 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): 5, http://tinyurl.com/l4bmy8v.
[14] Ibid.
[15] Detailed information about the STAMP® model can be found at http://www.beaconhill.org/STAMP_Web_Brochure/STAMP_HowSTAMPworks.html.

or by 3.69 percent. The RPS mandate will cost New Hampshire electricity customers $704 million over the period from 2015 to 2025.

Table 1: The Cost of the RPS Mandate on New Hampshire in 2025

Costs Estimates (2011 $)	**Expected**
Total Net Cost in 2025 ($ million)	(70)
Total Net Cost 2015-2025 ($ million)	(703)
Electricity Price Increase in 2025 (cents per kWh)	0.52
Percentage Increase (%)	3.69
Economic Indicators	
Total Employment (jobs)	(720)
Investment ($ million)	(9.6)
Real Disposable Income ($ million)	(70)

The STAMP model simulation indicates that, upon full implementation, the RPS law is likely to hurt New Hampshire's economy. The state's ratepayers will face higher electricity prices that will increase their cost of living, which will in turn put downward pressure on households' disposable income. By 2025, the New Hampshire economy will shed a net of 720 jobs. This includes jobs created in the renewable energy sector as well as the jobs lost due to higher electricity costs and dynamic spending decreases.

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 2025, real disposable income will fall by an expected $70 million. Furthermore, net investment will fall by $9.6 million.

Table 2: Annual Effects of RPS on Electricity Ratepayers

(2012 $)	**Expected**
Cost in 2025	
Residential Ratepayer ($)	40
Commercial Ratepayer ($)	230
Industrial Ratepayer ($)	3,655
Cost over period (2015-2025)	
Residential Ratepayer ($)	405
Commercial Ratepayer ($)	2,370
Industrial Ratepayer ($)	36,730

Table 2 shows how the RPS mandate is expected to affect the annual electricity bills of households and businesses in New Hampshire. In 2025, the RPS is expected to cost families an additional $40 per year; commercial businesses $230 per year; and industrial businesses $3,655 per year. Over the entire period from 2015 to 2025, the RPS will cost families an additional $405; commercial businesses $2,370; and industrial businesses $36,730.

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.

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, or more recently the decline in oil prices.

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.

Table 3: Monte Carlo Analysis

Costs Estimates (2013 $)	**Confidence Interval**	
Total Net Cost in 2025 ($ million)	(29)	(112)
Total Net Cost 2015-2025 ($ million)	(389)	(1,018)
Electricity Price Increase in 2025 (cents per kWh)	(0.21)	(0.84)
Percentage Increase (%)	1.50	5.88
Economic Indicators		
Total Employment (jobs)	(290)	(1,145)
Investment ($ million)	(3.9)	(15.3)
Real Disposable Income ($ million)	(29)	(112)
Cost in 2025		
Residential Ratepayer ($)	15	60
Commercial Ratepayer ($)	95	365
Industrial Ratepayer ($)	1,485	5,825
Cost over period (2015-2025)		
Residential Ratepayer ($)	225	585
Commercial Ratepayer ($)	1,320	3,420
Industrial Ratepayer ($)	20,370	53,085

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 above. Thus, we arrive at 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.[16] Thus, our conclusion that the RPS mandate is economically harmful is robust.

The first row in Table 3 shows that with a 90 percent confidence, the net costs in 2025 will fall between $29 million and $112 million. The costs translate into average electricity price increases of 0.21 cents per kWh and 0.84 cents per kWh, or a 1.50 percent and 5.88 percent rate increase. Thus, we are more than 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. 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 290 jobs to 1,145 jobs, and disposable income losses of $29 million to $112 million. Investment losses will tally from $3.9 million to $15.3 million.

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

Conclusion

Many proponents of Renewable Portfolio Standards claim that the policies are all benefit with no cost. They see a stronger economy in the form of lower electricity rates and the creation of green jobs. This is the policy equivalent of a free lunch. 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 face higher electricity prices. This means that every business and manufacturer in the state will face higher costs, leading to less investment in both capital and labor. Moreover, every household will have less money to spend on everything from groceries, to entertainment, to transportation, to housing.

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 foregone opportunities that would have been created with these resources are not easily observed.

In New Hampshire this is even less the case than in other states, due to the implementation of the RPS. Alternative Compliance Payments are being widely used for some of the Classes, meaning that the cost is incurred, without encouraging the renewable source. Those ACPs are less reliable as a down payment on encouraging renewable energy because the legislature has shown that it is not reluctant to tap associated funds for general operating budget shortfalls. Overall, this implementation turns the RPS into nothing more than a regressive tax on electricity to increase general spending.

The RPS continues to generate economic benefits for a small group of favored industries. But all of New Hampshire's electricity customers will pay higher rates, diverting resources away from investment and spending on other sectors. The implementation of the NH RPS accentuates this issue by requiring existing biomass and small hydro, which provide a declining supply of RECs. Since these producers can make more money satisfying other states' RPSs, it works to drive up electricity costs without creating any of the expected benefits.

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 New Hampshire to locations with lower electricity prices. Therefore the RPS policy will not have an impactful effect on reducing global emissions, but rather send jobs and capital investment outside the state.

Appendix

The RPS classifies mandated energy sources by Class I, Class II, Class III and Class IV.[17] Class I encompasses the conventional renewables, including wind, solar, geothermal, biomass and thermals. Class II represents a "carve-out" for solar energy, while Class III is set aside for small thermal sources that began production before 2006. Class IV energy is also a carve-out but is restricted to hydroelectric generators that were in place before 2006.

Utilities obtain Renewable Energy Credits (RECs) for each megawatt-hour (MWh) of electricity generated by renewable sources. These RECs must be certified according to the regional generation information system, administered by ISO New England and the New England Power Pool.[18]

To provide a statistically significant confidence interval for net cost calculations for state level Renewable Portfolio 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.[19]

Determining the Levelized Energy Cost Distribution

Determining the mean value and standard deviation of electricity is the first step in building a Monte Carlo simulation. We relied upon data from 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.[20]

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

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[17] New Hampshire Public Utilities Commission, "Electric Renewable Portfolio Standard," http://www.puc.state.nh.us/sustainable%20Energy/Renewable_Portfolio_Standard_Program.htm.
[18] NH General Law. Title XXXIV, Section 362-F:6 http://www.gencourt.state.nh.us/rsa/html/XXXIV/362-F/362-F-mrg.htm.
[19] Oracle Crystal Ball, Overview, http://www.oracle.com/us/products/applications/crystalball/overview/index.
[20] 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.

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 as Mean(Wind, NPCC/NE, 2020). This level of detail enabled the modeling of state specific RPS with varying requirements year to year.

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.[21] 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.[22] 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 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 AOE2013 Region Matching

AEO 2008 Region*	AEO 2013 Region*
1	10, 11, (½)15,
2	1
3	6, 7, 9
4	3, (⅓) 4, 13
5	(⅔)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.

[21] Energy Information Administration, "Issues in Focus," April 2013, http://www.eia.gov/forecasts/aeo/IF_all.cfm
[22] U.S. Bureau of Labor Statistics, Consumer Price Index, http://www.bls.gov/cpi/.

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.[23] 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 prices, including rare earth metals, 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.

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.[24] To determine the strength and interaction we produced the following simple regression.

$$Log(Electricity\ Consumption = \beta_0 + \beta_1\ Log(SGDP)$$

Or

$$Log(Electricity\ Consumption = 13.14318 + 0.279606\ Log(SGDP)$$

[23] Energy Information Administration, Forecasts, http://www.eia.gov/forecasts/aeo/ and http://www.eia.gov/oiaf/archive/aeo08/index.html.

[24] See BLS and EIA: http://www.bea.gov/regional/index.htm and http://www.eia.gov/electricity/data.cfm.

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: Revenant Regression Statistics

Adjusted R^2	0.8877
Prob>T	0.000
Standard Error Log(SGDP)	0.0216389
Number of Observations	22

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 annual variations in State GDP. 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 New Hampshire, 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 2007, as the policy was established in New Hampshire in May of 2007.[25] This amount was then adjusted annually according to the projected growth of renewables in the region per the AEO2007.[26]

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[25] Energy Information Administration, "Table 5. State Renewable Electric Power Industry Net Generation, by Energy Source, 2006 - 2010 (Thousand MWh)" http://www.eia.gov/renewable/state/newhampshire/.
[26] Energy Information Administration, "Supplement Tables to the Annual Energy Outlook 2007, Table 84. Renewable Energy Generation by Fuel Northeast Power Coordinating Council / New England" (February 2007) http://www.eia.gov/oiaf/archive/aeo07/supplement/index.html.

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 several data points. First, we determined the amount of Class I, Class I thermal, Class II, Class III and Class IV required for each year. This was then raised using EIA projections for generation growth by region. Class I thermal requirements we assumed would be met by biomass, the most affordable and therefore most conservative estimate, as opposed to solar thermal. Class II can only be met with solar, so that was a direct requirement for solar. The remainder of Class I renewables will be met by a variety of technologies. To determine the share of various renewables that would be used to meet Class I requirements, we used estimates from Synapse Energy Economics combined with projections from the New Hampshire Public Utilities Commission. Synapse projected how Class I renewables in New England would be met, which we used to calculate the ratio of wind, biomass, NGFC and hydroelectricity.[27] We combined this information with the PUC on the ratio between onshore and offshore wind.[28]

Attempting to correctly determine the costs and benefits of the Class III and Class IV carve outs over the course of the RPS policy presents unique challenges. Since these Classes require the purchasing of RECs from legacy energy production, new sources could not be brought online to meet the demand. We reviewed current Public Utilities Commission documents and found that the majority of Class III RECs are not actually used or retired for the NH-RPS, but Alternative Compliance Payments (ACP) are used to meet the goal, and it is thought by many in the industry that this will continue in the future.

For example, Liberty Utilities said, "there are virtually no Class III resources willing to sell RECs below the Class III ACP;" while PSNH said, "current Class III eligible resources can now earn higher revenues selling RECs elsewhere;" and Wood-Fired Independent Power Producers said, "it is reasonable to assume that eligible Class III wood-fired REC supply, and any potentially eligible Class III wood-fired plants, would first seek to sell its RECs in Connecticut and are not likely to produce significant, if any, Class III REC sales in in (sic) New Hampshire in the 2013-2014 time frame."[29] This same conclusion was reached by Bridgewater Power Company:

> The primary reason RECs are sold into RPS programs of other states is due to the level of ACP rates in the NHRPS and the effect those rates have on the REC prices as compared to the ACP rate and resulting REC prices available in other state programs. For example, an ACP of $31 means that regardless of supply scarcity, RECs can never sell for more than that ceiling price. If a REC seller can sell into another states RPS with an ACP it will do so provided that ACP

[27] Synapse Energy Economics, Inc., *Avoided Energy Supply Costs in New England: 2013 Report*. Exhibit 6-28.
[28] NHPUC. *Report of the New Hampshire Public Utilities Commission to the New Hampshire General Court*. Figure 4. http://www.puc.state.nh.us/sustainable%20Energy/RPS/RPS%20Review%202011.pdf.
[29] NHPUC. Adjustment to Class I and Class III Renewable Portfolio Requirements. April 4, 2013.

produces REC prices greater than those obtainable in the $31 ACP market. This is the situation today in the NHRPS class III Market.[30]

The above comments led to a reduction of the NH Class III carve out in 2012 through 2014. This will return to the eight percent requirement in 2015 onwards under current law. In reviewing the recent payments and the requirements of surrounding states escalating RPS requirements, we determined that the Class III requirements will be completely met by ACP. These payments are equal to $31.93 per MWh, and will grow at the rate of inflation.

It was more difficult to find available numbers for the calculation for Class IV renewables. Legacy hydroelectricity is much more prevalent, is completive in the open market and has a relatively low requirement (1.5 percent versus eight percent for Class III). Yet, over the last four years, about one third of the requirement was met with ACPs.[31] We project that this will continue with 33 percent of the requirement being met with ACPs.

The results of our baseline calculations are presented below in Table 6. As mentioned in our discussion about Class III and IV renewables, the baseline-projected renewables are quite sizable but are biomass and hydroelectricity, which mainly sell their RECs outside of the state for an amount higher than the ACP, meaning they are not used to meet most of the RPS.

Table 6: Projected Electricity Sales, Renewable Sales

Year	Projected Electricity Sales	Projected Renewable	RPS Requirement
	MWhs (000s)	MWhs (000s)	MWhs (000s)
2014	11,789.86	2,261.05	1,143.62
2015	12,028.65	2,270.00	1,900.53
2016	12,247.58	2,302.04	2,045.35
2017	12,447.10	2,302.04	2,190.69
2018	12,622.03	2,329.52	2,335.08
2019	12,779.13	2,269.71	2,479.15
2020	12,946.89	2,269.71	2,628.22
2021	13,105.85	2,269.71	2,778.44
2022	13,073.82	2,269.71	2,889.31
2023	13,194.69	2,269.71	3,034.78
2024	13,317.70	2,269.79	3,182.93
2025	13,437.29	2,269.89	3,332.45

[30] Open letter to NH Office of Energy & Planning, July 25, 2014, http://www.nh.gov/oep/energy/programs/documents/sb191pc-2014-7-25-biomass-companies.pdf.
[31] NHPUC, Annual Compliance Reports. http://www.puc.state.nh.us/sustainable%20Energy/Renewable_Portfolio_Standard_Program.htm

Some types of renewable generation, such as wind and solar power, are considered intermittent power sources.[32] 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 are required 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, rising to 0.3 percent of total grid capacity for each percent of wind penetration above 20 percent.[33]

We reviewed the original Gross article, which compiled numerous papers on the topic, and found the Reason Foundation calculations to be very conservative. Using the Reason Foundation numbers to err on the modest side, (i.e. factoring in less spinning reserves), the results from this calculation were more favorable to renewable sources.

Finally, a calculation of the distribution of conventional energy resources is needed – one that finds out how much would be crowded out due to a higher share of renewables. In New Hampshire, nuclear power is the largest power source and is not included in RPS. But it is a baseline source of power that is unlikely to be replaced. Natural gas and coal make up majority of the remaining non-RPS sources and are more dispatchable and therefore likely to be the generation techniques replaced.[34] For this reason, we assume that approximately 15 percent of the replaced electricity sources will be coal, and the remainder natural gas, depending on the ratio of the projected energy source by year.

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.

[32] 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:nhhfms:2014_017&r=ene.

[33] 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.

[34] U.S. Energy Information Administration, New Hampshire Electricity Profile, as in "Table 5. Electric Power Industry Generation by Primary Energy Source, 1990 through 2010. "http://www.eia.gov/electricity/state/Newhampshire/.

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 industrial.[35] 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.[36]

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 7,353 kWh of electricity in 2025 and the expected percent rise in electricity to be by 0.52 cents per kWh in the same year. Therefore, we expect residential ratepayers to pay an additional $38 in 2025.

[35] Energy Information Administration, "Electric Sales, Revenue, and Average Price," at http://www.eia.gov/electricity/sales_revenue_price/.
[36] Energy Information Administration, "Electric Power Projections for EMM Regions," http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013ER&subject=0-AEO2013ER&table=62-AEO2013ER&region=3-5&cases=early2013-d102312a.

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.

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.

The STAMP® model identifies 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.[37]

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, Pennsylvania North Carolina, Indiana, Kansas, and Washington. 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

[37] For a clear introduction to CGE tax models, see John B. Shoven and John Whalley, "Applied 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).

changes together to determine the average effect of the three utility increases. Table 7 displays these elasticities, which were then applied to the calculated percent change in electricity costs for the state as discussed above.

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.[38]

[38] 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/.

About the Authors

Paul Bachman is Director of Research at BHI. He manages the institute's research projects, including the development and deployment of the STAMP model. Mr. Bachman has authored research papers on state and national tax policy and state labor policy. He also produces the Institute's state revenue forecasts for the Massachusetts legislature. He holds a Master Science in International Economics from Suffolk University.

Michael Head is a Research Economist at BHI. Mr. Head has authored research papers on state tax policy and energy policy. He holds a Master of Science in Economic Policy from Suffolk University.

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THE BEACON HILL INSTITUTE
FOR PUBLIC POLICY RESEARCH
Suffolk University
8 Ashburton Place
Boston, MA 02108
Phone: 617-573-8750 Fax: 617-994-4279
bhi@beaconhill.org
http://www.beaconhill.org