American Tradition Institute

The Economic Impact of Minnesota's Renewable Portfolio Standard

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APRIL 2011

Table of Contents

Table of Tables

Executive Summary

In February 2007, Minnesota enacted legislation (known as "S.F. 4") requiring renewable energy sources to comprise 12 percent of retail electricity sales by 2012, 17 percent by 2016, 20 percent by 2020 and 25 percent by 2025. Additionally, S.F. 4 subjects Xcel Energy, one of the nation's largest power suppliers, to a 30 percent standard by 2020.

The American Tradition Institute and the Minnesota Free Market Institute commissioned the Beacon Hill Institute to apply its STAMP® (State Tax Analysis Modeling Program) to estimate the economic effects of the Renewable Portfolio Standard (RPS) mandate. To account for the shortcomings of optimistic Energy Information Administration ("EIA") measures of renewable electric costs and capacity factors, this study provides three estimates of the cost of Minnesota's RPS mandates – low, average and high – using different cost and capacity factor estimates for electricity-generating technologies from the academic literature. Major cost findings include:

- The state's electricity consumers will pay $2.29 billion more for power in 2025, within a range of $865 million and $3.53 billion due to the RPS.
- Over the period of 2016 to 2025, Minnesotans will pay an additional $15.04 billion over a baseline of no RPS, within a range of $7.17 billion and $22.83 billion.
- Minnesota's electricity prices will increase by an average of 24 percent, in 2025, within a range of 9 percent and 37 percent.

These increased energy prices will hurt Minnesota's households and businesses and will impair the state economy. According to the study by 2025:

- Minnesota will lose an average of 11,271 jobs, within a range of 4,539 jobs and 17,164 jobs.
- The RPS mandate will reduce annual wages by an average of $736 per worker, within a range of $297 per worker and $1,121 per worker.
- Due to higher home energy costs, annual real disposable income will fall by $1.36 billion, within a range of $547 million and $2.07 billion.
- Net investment will fall by $109 million, within a range of $44 million and $165 million.
- The policy will cost families on average $265 per year, commercial businesses on average $2,257 per year and industrial businesses on average $70,681 per year.
- From 2015 to 2025, the average household ratepayer will pay $1,814 in higher electricity costs; the average commercial ratepayer will pay an extra $8,011 and the average industrial ratepayer an extra $250,882.

Introduction

Minnesota was one of the first states in the nation to enact legislation dictating the mix of electricity generation technologies private power companies must sell. Enacted in 1994, Minnesota required Xcel Energy to produce 125 MW of power using biomass sources by 2004.[1] Since then, Minnesota has imposed additional laws governing the power mix that Xcel Energy must provide to the states electric consumers.

In February 2007 Minnesota passed Senate File (S.F.) 4, which established a Renewable Portfolio Standard (RPS) that requires a portion of all retail electricity sold in Minnesota be derived from renewable sources, including energy from solar, wind, biomass and hydroelectric facilities smaller than 100 megawatts. Specifically, the law requires that renewable sources account for 12 percent of all retail electricity sales by 2012; 17 percent by 2016; 20 percent by 2020 and 25 percent by 2025 and after.[2]

In addition to expanding the RPS to include all energy purchased in Minnesota, S.F. 4 created a separate, more demanding, schedule for Xcel Energy.[3] This policy requires that Xcel derive 30 percent of its retail sales from renewable sources by 2020. Additionally, the law requires that wind power comprise at least 80 percent of Xcel's 30 percent mandate, meaning that 24 percent of sales originate from wind power.[4]

The Minnesota RPS statute allows for the modification or delay of the standard, should the Public Utilities Commission determine it would be in the best interest of the public. The criteria for this include economic or competitive pressures, effects on the reliability of the system, transmission constraints and unforeseen delays.[5]

Most renewable electricity sources are more costly and unreliable than conventional energy sources such as coal and natural gas, and stand little chance of commercial success in a competitive market. In response, producers of renewable energy seek to guarantee a market through RPS legislation. But whatever the market offers in terms of renewable energy it will always be limited. In order to keep the electricity grid in equilibrium, intermittent resources such as wind and solar power need reliable back-up sources. If the wind dies down, or blows too hard (which trips a shutdown mechanism in commercial windmills), another power source must be ramped up instantly.

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[1] Minn. Stat. §216B.2424, Sec. 3.

[2] Minn. CHAPTER 110--S.F.No. 550 https://www.revisor.mn.gov/laws/?id=110&year=2009&type=0.

[3] For this study we only calculated the lower, statewide RPS, but the Xcel RPS mandate, which requires that renewable sources account for 15 percent of all power generated by 2010; 18 percent for 2012; 25 percent for 2016 and 30 percent for 2020 and thereafter.

[4] Ibid.

[5] Minn. Stat. §216B.1691 https://www.revisor.mn.gov/statutes/?id=216b.1691.

Not unlike taxes, higher electricity prices produce negative effects on economic activity. Prosperity and economic growth depend upon access to reliable and competitively priced energy. Since electricity is an essential commodity, consumers will have limited opportunity to avoid these costs. For low-income consumers, these energy taxes will force difficult choices between energy and other necessities such as such as food, transportation and shelter.

In this report, the American Tradition Institute and the Minnesota Free Market Institute commissioned the Beacon Hill Institute (BHI) to estimate the costs of the RPS mandate and the economic impact of the legislation on the state economy. To that end, BHI applied its STAMP® models (State Tax Analysis Modeling Program) to estimate the economic effects of the state RPS mandate.

Estimates and Results

There exist a wide variety of cost estimates for renewable electricity sources. The U.S. Energy Information Agency (EIA), a division of the Department of Energy, provides estimates for the cost of conventional and renewable electricity generating technologies. A literature review shows that in most cases the EIA's projected costs can be found at the low end of the range of estimates while the EIA's capacity factor for wind to be at the high end of the range.[6]The EIA, however, appears not to take into account the actual experience of existing renewable electricity power plants.

In light of the wide divergence in the costs and capacity factor estimates available for the different electricity generation technologies, we provide three estimates of the effects of Minnesota RPS mandate using low, average and high cost projections of both renewable and conventional generation technologies. Each estimate represents the change that will take place in the indicated variable against the assumption that the RPS mandate would not be implemented. The Appendix contains details of our methodology. Table 1 displays our estimates of the cost and economic impact of the Minnesota RPS mandate.

The RPS will impose costs of $2.294 billion in 2025, within a range of $865 million and $3.526 billion. For the period of 2016 – 2025 the RPS mandate will cost $15.042 billion with a low estimate of $7.173 billion and a high of $22.828 billion. As a result, the RPS mandate will increase electricity prices by 2.34 cents per kilowatt-hour (kWh) or 24 percent, within a range of 0.88 cents per kWh, or 9 percent and 3.59 cents per kWh, or 37 percent.[7]

[6] The capacity factor measures the ratio of electrical energy produced by a generating unit over a period of time to the electrical energy that could have been produced at 100 percent operation during the same period.

[7] We converted the aggregate cost of the RPS into a cost per-kWh by dividing the cost by the estimated total number of kWh sold for that year. For example, for 2025 under the high cost scenario above, we divided $3,526 million into 98,250 million kWhs for a cost of 3.59 cents per kWh.

Table 1: The Cost of the RPS Mandate to Minnesota (2010 $)

Costs Estimates	Low	Medium	High
Total Net Cost in 2025 ($ m)	865	2,294	3,526
Total Net Cost 2016-2025 ($ m)	7,173	15,042	22,828
Electricity Price Increase in 2025 (cents per kWh)	0.88	2.34	3.59
Percentage Increase	9%	24%	37%
Economic Indicators			
Total Employment (jobs)	(4,539)	(11,271)	(17,164)
Gross Wage Rates ($ per Worker)	(297)	(736)	(1,121)
Investment ($ m)	(44)	(109)	(165)
Real Disposable Income ($ m)	(547)	(1,359)	(2,070)

Upon full implementation, the RPS law will dampen economic output in Minnesota. Minnesota's ratepayers will face higher electricity prices, which will increase the cost of living and doing business in the state. By 2025, Minnesota will employ 11,271 fewer workers, within a range of 4,539 and 17,164 workers.

The decrease in labor demand – as seen in the job losses – will cause gross wages to fall. In 2025, the Minnesota RPS will reduce annual wages by $736 per worker, within a range of $297 and $1,121 per worker.

The job losses and price increases will reduce real incomes as firms, households and governments are forced to allocate more of their resources to purchase electricity and less to purchase other items. In 2025, annual real disposable income will fall by $1.359 billion, within a range of $547 million and $2.070 billion under our low and high cost scenarios respectively.

In 2025, net investment will fall by $109 million, within a range of $44 million and $165 million. The relatively moderate investment losses will be offset by the investments required to build renewable power plants, transmission lines and reconfigurations to the electricity grid. However, these investments are not a productive as the ones based on conventional energy because the renewable mandate works its way through the production methods less efficiently. A good analogy would be applying a mandate to telecommunications. An RPS is akin to requiring that 25 percent of all Internet access comprise of dial-up service over plain telephone service lines. Business would indeed be good for dial-up modem manufacturers Internet Service Providers would need to retrofit their networks but this investment would not increase productivity in the economy.

Table 2 shows how the RPS will affect the annual electricity bills of households and businesses in Minnesota. In 2025, the RPS will cost families on average of $265 per year, commercial businesses on average of $2,257 per year, and industrial businesses on average $70,681 per year. Between 2016 and 2025, the average household ratepayer will pay $1,814 in higher electricity costs; the average commercial ratepayer will spend an extra $8,011 and the average industrial ratepayer an extra $250,882.

Table 2: Effects of RPS on Electricity Ratepayers (2010 $)

	Low	Medium	High
Cost in 2025			
Residential Ratepayer ($)	100	265	407
Commercial Ratepayer ($)	851	2,257	3,469
Industrial Ratepayer ($)	26,653	70,681	108,636
Total over period (2016-2025)			
Residential Ratepayer ($)	871	1,814	2,752
Commercial Ratepayer ($)	4,880	8,011	11,950
Industrial Ratepayer ($)	152,832	250,882	374,223

One could justify the higher electricity costs if the environmental benefits, in terms of reduced GHG emissions, outweighed the costs. But it is unclear that the use of renewable energy resources, especially wind and solar, significantly reduces GHG emissions. Due to their intermittency, wind and solar require significant backup power sources that are cycled up and down to accommodate the variability in the production. Those power sources remain dirty ones. As a result, a recent study found that wind power could actually increases pollution and greenhouse gas emissions.[8] Thus the case for heavy uses of wind to generate "cleaner" electricity is undermined.

Manufacturers will avoid moving to states like Minnesota with hefty RPS mandates. Thus they will prove to be mobile as they are sensitive to electricity costs. They will opt for more favorable business climates. Therefore the Minnesota RPS policy will not reduce global emissions, but rather send jobs and capital investment outside the state.

[8] See "How Less Became More: Wind, Power and Unintended Consequences in the Colorado Energy Market," Bentak Energy, LLC. (Evergreen Colorado: May, 2010).

Conclusion

Minnesota has enacted a series of laws implementing RPS mandates based on the idea of promoting green energy polices. In reality these mandates are mere handouts to favored "green" energy producers. Equally problematic is the lack of transparency between cost and benefit. Not funded directly by higher taxes or debt, the RPS hides its costs in the higher prices to be paid in the future by ratepayers.

The paradigm driving renewable energy found in most RPS mandates is flawed. The model promotes only certain forms of renewable energy - very costly ones - and ignores potential other renewable sources such as hydroelectric power. Therefore, the "expanded development of these resources" will not "meet the state's electricity demand" but rather threaten the stability of the state's electricity grid – raising electricity prices for consumers and businesses in Minnesota. Moreover, many of the environmental benefits of wind and solar power are illusionary due to the necessity of keeping backup power generation sources online and available to cycle-up when wind power is unavailable.

Supporters of the Minnesota RPS use a hidden tax approach that fails to undertake any reasonable cost benefit analysis. The Minnesota RPS puts the state's robust competitiveness at risk. The Minnesota business community will most likely will see a reduction in its competitive advantage over domestic and international competitors. As a result, Minnesota will see slower growth in disposable income, employment and wages.

Appendix

Electricity Generation Costs

As noted above, governments enact RPS policies because most sources of renewable electricity generation are less efficient and thus more costly than conventional sources of generation. The RPS policy forces utilities to buy electricity from renewable sources and thus guarantees a market for the renewable source. These higher costs get passed on to electricity consumers including residential, commercial and industrial customers.

The U.S. Department of Energy's Energy Information Agency (EIA) estimates the Levelized Energy Cost (LEC), or financial breakeven cost per MWh to produce new electricity in its *Annual Energy Outlook*.[9] The EIA provides LEC estimates for conventional and renewable electricity technologies (coal, nuclear geothermal, landfill gas, solar photovoltaic, wind and biomass) assuming the new sources enter service in 2016. The EIA also provides LEC estimates for conventional coal, combined cycle gas, advanced nuclear and onshore wind only, assuming the sources enter service in 2020 and 2035.

While the EIA does not provide LEC for hydroelectric, solar photovoltaic and biomass for 2020 and 2035, it does project overnight capital costs for 2015, 2025 and 2035. We can estimate the LEC for these technologies and years using the percent change in capital costs to inflate the 2016 LECs. In its *Annual Energy Outlook*, the EIA incorporates many assumptions about the future price of capital, materials, fossil fuels, maintenance and capacity factor into their forecast. Table 3 shows over time the EIA projects that the LEC for all four electricity sources (coal, gas, nuclear and wind) fall significantly from 2016 to 2035. The fall in capital costs drives the drop in total system LEC over the period.

The EIA estimates that wind generation will benefit from lower transmission and maintenance costs. EIA forecasts that transmission costs for wind will drop from $8.4 per MWh in 2016 to $5.6 per MWh, or by 33 percent, between 2020 and 2035 and fixed operations and maintenance costs will drop from $11.4 per MWh to $8.9, or by 22 percent, over the same period. The drop in capital, maintenance and transmission costs combine to reduce wind power cost from $149.3 per MWh to $78.9 per MWh, or by an astounding 47.2 percent over the period. By 2035, wind would become the third least expensive behind biomass and natural gas.

[9] U.S. Department of Energy, Energy Information Agency, *2016 Levelized Cost of New Generation Resources from the Annual Energy Outlook 2010* (2008/$MWh), http://www.eia.doe.gov/oiaf/aeo/electricity_generation.html, (accessed September 20, 2010).

Table 3: Levelized Cost of Electricity from Conventional and Renewable Sources (2008 $)

Plant Type	Capacity Factor	Levelized Capital Costs	Fixed O&M	Variable O&M (with fuel)	Transmission Investment	Total Levelized Cost
Advanced Coal - 2016	0.850	81.2	5.3	20.4	3.6	110.5
2020		77.1	5.3	19.6	3.6	105.6
2035		55.9	5.3	20.2	3.5	84.9
Gas - 2016	0.870	22.9	1.7	54.9	3.6	83.1
2020		21.4	1.6	53.7	3.6	80.3
2035		15.6	1.6	54	3.7	74.9
Nuclear -2016	0.900	94.9	11.7	9.4	3.0	119.0
2020		86.9	11.7	9.9	3.0	111.5
2035		60.9	11.7	11.6	3.0	87.2
Wind - 2016	0.344	130.5	10.4	0.0	8.4	149.3
2020		81.6	8.9	0.0	5.6	96.1
2035		64.4	8.9	0.0	5.6	78.9
Solar PV - 2016	0.217	376.8	6.4	0.0	13.0	396.1
2025						297.7
2035						208.6
Biomass -2016	0.830	73.3	9.1	24.9	3.8	111.1
2025						62.8
2035						47.5
Hydro -2016	0.514	103.7	3.5	7.1	5.7	119.9
2025						101.3
2035						83.4

Using the EIA change in overnight capital costs for solar and biomass produces reductions in LECs similar to wind from 2016 to 2035. The biomass LEC drops by 57.3 percent and solar by 47.3 percent over the period. These compare to much more modest cost reductions of 23.1 percent for coal, 9.9 percent for gas and 26.7 percent for nuclear over the same period. EIA does provide overnight capital costs for renewable technologies under a "high cost" scenario. However, for each renewable technology the EIA "high cost" scenario projects capital costs to drop between 2015 and 2035.

Moreover the building of vast wind power plants will require large quantities of raw materials, particularly aluminum and other commodities. The rising demand for these commodities – from the construction of renewable energy plants and from fast growing emerging market economies – will certainly increase their prices and therefore costs for wind power plants. Aluminum prices have doubled over the past two years as the world economy emerges from the recession.[10] As a result capital and other costs are more likely to rise than fall over the next two decades.

Table 3 also displays capacity factors for each technology. The capacity factor measures the ratio of electrical energy produced by a generating unit over a period of time to the electrical energy that could have been produced at 100 percent operation during the same period. In this case, the capacity factor measures the potential productivity of the generating technology. Solar, wind and hydroelectricity have the lowest capacity factors due to the intermittent nature of their power sources. EIA projects a 34.4 percent capacity factor for wind power, which, as we will see below, appears to be at the high end of any range of estimates.

Estimating a capacity factor for wind power is particularly challenging. Wind is not only intermittent but its variation is unpredictable, making it impossible to dispatch to the grid with any certainty. This unique feature of wind power argues for a capacity factor rating of close to zero. Nevertheless, wind capacity factors have been estimated to be between 20 percent and 40 percent.[11] The other variables that affect the capacity factor of wind are the quality and consistency of the wind and the size and technology of the wind turbines deployed. As the U.S. and other countries add more wind power over time, presumably the wind turbine technology will improve, but the new locations for wind power plants will likely have diminishing or less productive wind resources.

The EIA estimates of LEC and capacity factors paint a particularly rosy view of the future cost of renewable electricity generation, particularly wind. Other forecasters and the experience of current renewable energy projects portray a less sanguine outlook.

Today wind and biomass are the largest renewable power sources and are the most likely to satisfy future RPS mandates. The most prominent issues that will affect the future availability and cost of renewable electricity resources are diminishing marginal returns and competition for scarce resources. These issues will affect wind and biomass in different ways as state RPS mandates ratchet up over the next decade.

Both wind and biomass resources face land use issues. Conventional energy plants can be built within a space of several acres and located close to large population centers with high electricity demand. However, a wind power plant with the same nameplate capacity (not actual capacity) would require many square miles of land. According to one study, wind power would require 7,579 miles of mountain ridgeline to satisfy current state RPS mandates

[10] MetalPrices.com, "LME Aluminum Price Charts," http://www.metalprices.com/FreeSite/metals/al/al.asp#MoreCharts (accessed January 2011).

[11] Renewable Energy Research Laboratory, University of Massachusetts at Amherst, "Wind Power, Capacity Factor and Intermittency: What Happens When the Wind Doesn't Blow?" Community Wind Power Fact Sheet #2a, http://www.ceere.org/rerl/about_wind/RERL_Fact_Sheet_2a_Capacity_Factor.pdf (accessed December, 2010).

and a 20 percent federal mandate by 2025.[12] Mountain ridgelines produce the most promising locations for electric wind production in the eastern and far western United States.

After taking into account capacity factors, a wind power plant would need a land mass of 20 by 25 kilometers to produce the same energy as a nuclear power plant that can be situated on 500 square meters.[13]

The need for large areas of land for situating wind power plants will require the purchase of vast areas of land by private wind developers and/or allowing wind production on public lands. In either case land acquisition/rent or public permitting processes will likely increase costs as wind power plants are built. Offshore wind is vastly more expensive than onshore wind power and suffers from the same type of permitting process faced by onshore wind power plants, as seen in the 10-year permitting process for the planned Cape Wind project off the coast of Massachusetts.

The swift expansion of wind power will also suffer from diminishing marginal returns as new wind capacity will be located in areas with lower and less consistent wind speeds. As a result, fewer megawatt hours of power will be produced from newly built windmills. Moreover the new wind capacity will be developed in increasing remote areas that will require larger investments in transmission and distribution, which will drive costs even higher.

The EIA estimates of the average capacity factor used for onshore wind power plants, at 34.4 percent, appears to be at the higher end of the estimates for current wind projects. This figure is inconsistent with estimates from other studies.[14] According to the EIA's own reporting from 137 current wind power plants in 2003, the average capacity factor was 26.9 percent.[15] In addition, a recent analysis of wind capacity factors around the world finds an actual average capacity factor of 21 percent.[16] Moreover, other estimates find capacity factors in the mid teens and as low as 13 percent.[17]

Biomass is a more promising renewable power source. Biomass combines low incremental costs relative to other renewable technologies and reliability. Biomass is not intermittent and therefore it is distributable with a capacity factor that is competitive with conventional energy

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[12] Tom Hewson and Dave Pressman, "Renewable Overload: Waxman-Markey RES Creates Land-use Dilemmas," *Public Utilities Fortnightly* 61 (August 1, 2009).

[13] "Evidence to the House of Lords Economic Affairs Committee Inquiry into 'The Economics of Renewable Energy'," Memorandum by Dr. Phillip Bratby, May 15, 2008.

[14] Nicolas Boccard, "Capacity Factors for Wind Power: Realized Values vs. Estimates," *Energy Policy* 37, no. 7 (July 2009): 2680.

[15] Cited by Tom Hewson, Energy Venture Analysis, "Testimony for East Haven Windfarm," January 1, 2005, http://www.windaction.org/documents/720 (accessed December 2010).

[16] Boccard.

[17] See "The Capacity Factor of Wind, Lightbucket," http://lightbucket.wordpress.com/2008/03/13/the-capacity-factor-of-wind-power/, (accessed December 22, 2010) and National Wind Watch, FAQ, http://www.wind-watch.org/faq-output.php (accessed December 2010).

sources. Moreover biomass plants can be located close to urban areas with high electricity demand. But biomass electricity suffers from land use issues even more so than wind.

The expansion of biomass power plants will require huge additional sources of fuel. Wood and wood waste comprise the largest source of biomass energy today. Other sources of biomass include food crops, grassy and woody plants, residues from agriculture or forestry, oil-rich algae, and the organic component of municipal and industrial wastes.[18] Biomass power plants will compete directly with other sectors (construction, paper, furniture) of the economy for wood and food products and arable land.

One study estimates that 66 million acres of land would be required to provide enough fuel to satisfy the current state RPS mandates and a 20 percent federal RPS in 2025.[19] When the clearing of new farm and forestlands are figured into the GHG production of biomass, it is likely that biomass increases GHG emissions.

The competition for farm and forestry resources would not only cause biomass fuel prices to skyrocket, but also cause the prices of domestically-produced food, lumber, furniture and other products to rise. The recent experience of ethanol and its role in surging corn prices can be casually linked to the recent food riots in Mexico and the struggle facing international aid organizations addressing hunger in places such as the Darfur region of Sudan. These two examples serve as reminders of the unintended consequences of government mandates for biofuels. The lesson is clear biofuels compete with food production and other basic products and distort the market.

Calculation of the Net Cost of New Renewable Electricity

To calculate the cost of renewable energy under the RPS, BHI used data from the Energy Information Agency (EIA), a division of the U.S. Department of Energy, to determine the percent increase in utility costs that Minnesota residents and businesses would experience. This calculated percent change was then applied to calculated elasticities, as described in the STAMP modeling section.

We collected historical data on the retail electricity sales by sector from 1990 to 2008 and projected its growth through 2025 using its historical compound annual growth rate (3.6 percent).[20] To these totals, we applied the percentage of renewable sales prescribed by the Minnesota RPS. By 2025, renewable energy sources must account for 25 percent of total electricity sales in Minnesota.

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[18] Biomass Energy Basics, National Renewable Energy Laboratory, Biomass Basics, http://www.nrel.gov/learning/re_biomass.html (accessed December, 2010).
[19] Hewson, 61.
[20] U.S. Department of Energy, Energy Information Agency, Minnesota Electricity Profile 2010, "Table 5: Electric Power Industry Generation by Primary Energy Source, 1990 Through 2008," http://www.eia.doe.gov/cneaf/electricity/st_profiles/minnesota.html. (accessed January 25, 2011).

Next we projected the growth in renewable sources that would have taken place absent the RPS. We used the EIA's projection of renewable energy sources by fuel for the Western Electricity Coordinating Council / Rocky Mountain Power Area and Arizona-New Mexico-Southern Nevada Power Area through 2025 as a proxy to grow renewable sources for Minnesota. We used the growth rate of these projections to estimate Minnesota's renewable generation through 2025 absent the RPS.[21]

Table 4: Projected Electricity Sales, Projected Renewable Sales and RPS Required Sales

Year	Projected Electricity Sales MWhs (000s)	Projected Renewable MWhs (000s)	RPS Requirement MWhs (000s)	Difference MWhs (000s)
2016	81,355	7,115	13,830	6,715
2017	83,078	7,115	14,123	7,008
2018	84,839	7,115	14,423	7,307
2019	86,636	7,115	14,728	7,613
2020	88,472	7,115	17,694	10,579
2021	90,346	7,115	18,069	10,954
2022	92,260	7,115	18,452	11,337
2023	94,215	7,115	18,843	11,728
2024	96,211	7,115	19,242	12,127
2025	98,250	7,115	24,562	17,447
Total	895,662	71,153	173,968	102,815

We subtracted our baseline projection of renewable sales from the RPS-mandated quantity of sales for each year from 2016 to 2025 to obtain our estimate of the annual increase in renewable sales induced by the RPS in megawatt hours (MWhs). The RPS mandate exceeds our projected renewable in all projected years (2016 to 2025). This figure also represents the maximum number of MWhs of electricity from conventional sources that are avoided, or not generated, through the RPS mandate. We will revisit this shortly. Table 4 above contains the results.

To estimate the cost of producing the additional extra renewable energy under an RPS against the baseline, we used estimates of the LEC, or financial breakeven cost per MWh to produce

[21] U.S. Department of Energy, Energy Information Agency, *Annual Energy Outlook 2010,* "Table 92: Renewable Electricity Generation by Fuel," http://www.eia.doe.gov/oiaf/archive/aeo10/aeoref_tab.html (accessed January 2010).

the electricity.[22] However, as outlined in the "electricity generation cost" section above, the EIA numbers provide a rather optimistic picture of the cost and generating capacity of renewable electricity, particularly for wind power. A literature review provided alternative LEC estimates that were generally higher and capacity factors that were lower for renewable generation technologies than the EIA estimates.[23] We used these alternative figures to calculate our "high" LEC estimates and the EIA figures to calculate our "low" cost estimates and the average of the two to calculate our "average" cost estimates. Table 5 displays the LEC and capacity factors for each generation technology.

We used the 2016 LEC for the years 2010 through 2018 to calculate the cost of the new renewable electricity and avoided conventional electricity, assuming that before 2016 LEC underestimates the actual costs for those years and for 2017 and 2018, the 2016 LEC slightly overestimates the actual costs. We assumed that the differences will, on balance, offset each other. For 2019 and 2020 we used the 2020 LEC. The assumption is that LEC will decline over time due to technological improvements over time.

We use the EIA's reference case scenario for all technologies. Since capital costs represent the large component of the cost structure for most technologies, we used the percentage change in the capital costs from 2015 to 2025 to adjust the 2016 LECs to 2025. For the technologies that the EIA does not forecast LECs in 2020, we used the average of the 2016 and 2025 LEC calculations, assuming a linear change over the period.

Once we computed new LECs for the years 2020 and 2025 we applied these figures to the renewable energy estimates for the remainder of the period.

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[22] U.S. Department of Energy, Energy Information Agency, *2016 Levelized Cost of New Generation Resources from the Annual Energy Outlook 2010* (2008/$MWh), http://www.eia.doe.gov/oiaf/aeo/electricity_generation.html (accessed September 2010).

[23] For coal, gas and nuclear generation we used the production cost estimates from the International Energy Agencies, Energy Technology Analysis Programs, "Technology Brief E01: Cola Fired Power, E02: Gas Fired Power, E03: Nuclear Power and E05: Biomass for Heat and Power," (April 2010), http://www.etsap.org/E-techDS/ (accessed December 2010). To the production costs we added transmission costs from the EIA using the ratio of transmissions costs to total LEC costs. For wind power we used the IEA estimate for levelized capital costs and variable and fixed O & M costs. For transmission cost we used the estimated costs from several research studies that ranged from a low of $7.88 per kWh to a high of $146.77 per kWh, with an average of $60.32 per MWh. The sources are as follows:
Andrew Mills, Ryan Wiser, and Kevin Porter, "The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies," Ernest Orlando Lawrence Berkeley National Laboratory, http://eetd.lbl.gov/EA/EMP (accessed December 2010); Competitive Renewable Energy Zones (CREZ) Transmission Optimization Study, The Electric Reliability Council of Texas, April 2, 2008 http://www.ercot.com/news/presentations/2006/ATTCH_A_CREZ_Analysis_Report.pdf (accessed December 2010); Sally Maki and Ryan Pletka, Black & Veatch, California's Transmission Future, August 25, 2010, http://www.renewableenergyworld.com/rea/news/article/2010/08/californias-transmission-future (accessed December 22, 2010).

Table 5: LEC and Capacity Factors for Electricity Generation Technologies

	Capacity Factor (percent)	Total Production Cost (cents/MWh) 2010	2020	2025
Coal				
Low	74.0	67.41	64.82	63.53
Average	79.5	83.96	85.21	79.39
High	85.0	100.50	105.60	95.25
Gas				
Low	85.0	75.86	73.25	73.25
Average	86.0	79.48	76.77	75.42
High	87.0	83.10	80.30	77.60
Nuclear				
Low	90.0	76.94	59.20	49.33
Average	90.0	97.97	85.35	74.34
High	90.0	119.00	111.50	99.35
Biomass				
Low	68.0	111.10	86.99	62.88
Average	75.5	112.50	95.27	80.62
High	83.0	113.90	103.54	98.36
Wind				
Low	15.5	148.78	96.10	87.50
Average	26.9	201.22	188.54	175.85
High	34.4	287.67	269.54	251.40

For conventional electricity we assumed that the technologies are avoided based on their costs, with the highest cost combustion turbine avoided first. For coal and gas, we assumed they are avoided based on their estimated proportion of total electric sales for each year. Although hydroelectric and nuclear are not the cheapest technology, we assume no hydroelectric or nuclear sources are displaced since most were built decades ago and offer relatively cheap and clean electricity today.

We also adjusted the avoided cost of conventional energy to account for the lower capacity factor of wind relative to conventional energy sources. We multiplied the cost of each conventional energy source by the difference between its capacity factor and the capacity factor for the renewable source and then by the ratio of the new generation of the renewable source to the total new generation of renewable under the RPS. For example, for coal, we multiplied the avoided amount generation of electricity from coal (11.543 million MWhs in 2025) by the LEC of coal ($79.39 per MWh) and then by the difference between the capacity factor of coal and the weighted average (using MWs as weights) capacity factor of wind (27 percent). This process is repeated for each conventional electricity resource.

These LECs are applied to the amount of electricity supplied from renewable sources under the RPS, because this figure represents the amount of conventional electricity generation capacity that presumably will not be needed under the RPS. The difference between the cost of the new renewable sources and the costs of the conventional electricity generation

Minnesota represents the net cost of the RPS. Tables 6, 7 and 8 display the results of our Average, Low and High Cost calculations respectively.

Table 6: Average Cost Case of RPS Mandate from 2016 to 2025

Year	Gross Cost (2010 $000s)	Less Conventional (2010 $000s)	Total (2010 $000s)
2016	1,214,425	147,989	1,066,436
2017	1,267,420	154,447	1,112,973
2018	1,321,538	161,042	1,160,496
2019	1,376,803	167,775	1,209,028
2020	1,755,445	226,390	1,529,054
2021	1,817,654	234,410	1,583,244
2022	1,881,181	242,603	1,638,578
2023	1,946,055	250,969	1,695,086
2024	2,012,303	259,513	1,752,790
2025	2,637,223	343,037	2,294,186
Total	**17,230,047**	**2,188,175**	**15,041,871**

We converted the aggregate cost of the RPS into a cost per-kWh by dividing the cost by the estimated total number of kWh sold for that year. For example, for 2025 under the high cost scenario above, we divided $3,526 million into 98,250 million kWhs for a cost of 3.59 cents per kWh.

Table 7: Low Cost Case of RPS Mandate from 2016 to 2025

Year	Gross Cost (2010 $000s)	Less Conventional (2010 $000s)	Total (2010 $000s)
2016	941,669	236,991	704,678
2017	982,762	247,333	735,429
2018	1,024,725	257,894	766,831
2019	1,067,577	268,670	798,907
2020	994,792	379,009	615,783
2021	1,030,046	392,421	637,625
2022	1,066,046	406,136	659,910
2023	1,102,809	420,142	682,667
2024	1,140,351	434,444	705,907
2025	1,429,211	564,113	865,098
Total	**10,779,988**	**3,607,153**	**7,172,835**

Table 8: High Cost Case of RPS Mandate from 2016 to 2025

Year	Gross Cost (2010 $000s)	Less Conventional (2010 $000s)	Total (2010 $000s)
2016	1,663,759	65,724	1,598,036
2017	1,736,363	68,592	1,667,771
2018	1,810,504	71,521	1,738,984
2019	1,886,217	74,514	1,811,703
2020	2,422,569	94,029	2,328,540
2021	2,508,420	97,366	2,411,054
2022	2,596,090	100,769	2,495,321
2023	2,685,617	104,244	2,581,373
2024	2,777,042	107,793	2,669,249
2025	3,672,574	146,416	3,526,158
Total	**23,759,155**	**930,968**	**22,828,189**

Ratepayer Effects

To calculate the effect of the RPS on electricity ratepayers we used EIA data on the average monthly electricity consumption by type of customer: residential, commercial and industrial.[24] The monthly figures were multiplied by 12 to compute an annual figure. We inflated the 2008 figures for each year using the average annual increase in electricity sales over the entire period.[25]

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 11,338 kWhs of electricity in 2025 and we expect the high cost scenario to raise electricity costs by 3.59 cents per kWh in the same year in our average cost case. Therefore we expect residential ratepayers to pay an additional $406.92 in 2025.

Modeling the RPS 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 proposals' 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 RPS requires Minnesota households and firms to use more expensive "green" power than they otherwise would have under a baseline scenario, the cost of goods and services will increase under the RPS. 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 RPS. 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

[24] U.S. Department of Energy, Energy Information Administration, "Average electricity consumption per residence in MT in 2008," (January 2010) http://www.eia.doe.gov/cneaf/electricity/esr/table5.html, The 2008 consumption figures were inflated to 2010 using the increase in electricity demand from the EIA of 0.89 percent compound annual growth rate.

[25] U.S. Department of Energy, Energy Information Agency, *Annual Energy Outlook 2010*, "Table 8: Electricity Supply, Disposition, Prices, and Emissions," http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html. (accessed December 22, 2010).

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.[26]

In order to estimate the economic effects of a national RPS 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.

First, we computed the percentage change to electricity prices as a result of three different possible RPS policies. We used data from the EIA from the state electricity profiles, which contains historical data from 1990-2008 for retail sales by sector (residential, commercial, industrial, and transportation) in dollars and MWhs and average prices paid by each sector.[27] We inflated the sales data (dollars and MWhs) though 2020 using the historical growth rates for each sector for each year. We then calculated a price for each sector by dividing the dollar value of the retails sales by kWhs. Then we calculated a weighted average kWh price for all sectors using MWhs of electricity sales for each sector as weights. To calculate the percentage electricity price increase we divided our estimated price increase by the weighted average price for each year. For example, in 2025 for our high cost case we divided our average price of 9.738 cents per kWh by our estimated price increase of 3.59 cents per kWh for a price increase of 36.87 percent.

Table 9: Elasticities for the Economic Variables

Economic Variable	**Elasticity**
Employment	-0.022
Gross wage rates)	-0.063
Investment	-0.018
Disposable Income	-0.022

[26] 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).

[27] U.S. Department of Energy, Energy Information Agency, Minnesota Electricity Profile 2010, Table 8: Retail Sales, Revenue, and Average Retail Price by Sector, 1990 through 2008, http://www.eia.doe.gov/cneaf/electricity/st_profiles/minnesota.html (accessed January 2011).

Using these 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 state's economy. We then averaged the percent changes together to determine what the average effect of the three utility increases. Table 9 displays these elasticities, which were then applied to the calculated percent change in electricity costs for the state of Minnesota discussed above.

We applied the elasticities to percentage increase in electricity price and then applied the result to Minnesota economic variables to determine the effect of the RPS. 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.[28] For example, under our high cost scenario we multiplied the electricity price increase (37 percent) by the employment elasticity (-.021535 percent) and the result by total employment estimated for 2025 (2,509,796) to get our employment estimate of 17,164.

[28] See the following: Bureau of Economic Analysis, "National Economic Accounts," http://www.bea.gov/national/; Regional Economic Accounts, http://www.bea.gov/regional/index.htm. See also Bureau of Labor Statistics, "Current Employment Statistics ," http://www.bls.gov/ces/.

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The authors would like to thank Frank Conte, BHI Director of Communications, for his editorial assistance.

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