



## The Economic Impact of Colorado's Renewable Portfolio Standard

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## Executive Summary

In November 2004 Colorado passed Amendment 37, the first voter-approved ballot initiative to create a Renewable Portfolio Standard (RPS) in the United States. In 2007 this law was expanded in House Bill 1281 and its current iteration was detailed in House Bill 1001 in 2010.<sup>1</sup> HB 1001 accelerated the timeline such that by 2020, 30 percent of all retail electricity in Colorado must be derived from a renewable source, including energy from solar, wind, geothermal, hydrogen derived from renewable sources, biomass and small hydroelectric facilities.

Specifically the Act requires that Colorado's Investor-Owned Utilities increase the percentage of electricity generated from new renewable energy sources. The RPS mandates that renewable sources account for 5 percent of all power generated by 2010; 12 percent by 2011-2014; 20 percent by 2015-2019 and 30 percent for 2020 and thereafter.<sup>2</sup>

The Bill also contains a measure to control costs for retail customers, by limiting the RPS costs that utilities can pass to customers to "two percent of the total electric bill annually for each customer."<sup>3</sup> But this provision only covers the incremental costs, referred to as the Renewable Energy Standard Adjustment on utility bills. The Electric Commodity Adjustment (ECA) fee is not subject to the 2 percent cap and will absorb the rest of the costs, such as backup energy and capital construction. As a result the cap has no effect on containment of cost increases due to the RPS.<sup>4</sup>

Another component of the Bill – the banking of unused renewable energy credits – helps defray costs initially. By producing more renewable energy than required by law in the first few years of the 5 percent RPS requirement, producers can 'bank' these extra units, to reduce the required number of units required in the future, when the mandate increases.

Since renewable energy generally costs more than conventional energy, many have voiced concerns about higher electric rates. In addition some renewable energy sources – wind and solar power in particular – require the installation of conventional backup generation capacity

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<sup>1</sup> Colorado General Assembly, HB 1281, "Concerning Increased Renewable Energy Standards," STANDARDS. [http://www.leg.state.co.us/CLICS/CLICS2007A/csl.nsf/fsbillcont3/C9B0B62160D242CA87257251007C4F7A?Open&file=1281\\_enr.pdf](http://www.leg.state.co.us/CLICS/CLICS2007A/csl.nsf/fsbillcont3/C9B0B62160D242CA87257251007C4F7A?Open&file=1281_enr.pdf). HB 1001 "Concerning Incentives for the Installation of New Distributed Renewable Energy, etc. [http://www.leg.state.co.us/CLICS/CLICS2010A/csl.nsf/fsbillcont3/47C157B801F26204872576AA00697A3F?Open&file=1001\\_enr.pdf](http://www.leg.state.co.us/CLICS/CLICS2010A/csl.nsf/fsbillcont3/47C157B801F26204872576AA00697A3F?Open&file=1001_enr.pdf) (accessed January 30, 2011).

<sup>2</sup> Ibid. HB1001.

<sup>3</sup> Ibid. HB1001, 8.

<sup>4</sup> William Yeatman, Amy Oliver Cooke, "Colorado's Great Green Deception: If HB 1001 Seems too Good to Be True, It's Because It Is," Competitive Enterprise Institute, Internet available at <http://cei.org/sites/default/files/William%20Yeatman%20and%20Amy%20Oliver%20Cooke%20-%20Colorado%27s%20Great%20Green%20Deception.pdf> (accessed January 2011).

for cloudy, windless days. The need for this backup further boosts the cost of renewable energy.

The American Tradition Institute commissioned the Beacon Hill Institute at Suffolk University (BHI) to estimate the costs of these House Bills and their impact on the state's economy. To that end, BHI applied its STAMP<sup>®</sup> (State Tax Analysis Modeling Program) to estimate the economic effects of the state RPS mandate.<sup>5</sup>

There exists 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. However the EIA's assumptions are optimistic regarding the cost and capacity of renewable electricity generating sources to produce reliable energy.

A review of the literature 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. The EIA does not take into account the actual experience of existing renewable electricity power plants. Therefore we provide three estimates of the cost of Colorado's RPS mandate: low, average and high, using different cost and capacity factors estimates for electricity-generating technologies from the academic literature. Table 1 displays our cost estimates.

**Table 1: The Cost of Colorado's RPS Mandate (2010 \$)**

<b>Costs Estimates</b>	<b>Low</b>	<b>Medium</b>	<b>High</b>
Total Net Cost in 2020 (\$ millions)	841	1,371	2,122
Total Net Cost 2011-2020 (\$ millions)	6,412	11,778	18,520
Electricity Price Increase in 2015 (cents per kWh)	1.23	3.75	5.97
Percentage Increase	13%	40%	64%
<b>Economic Indicators</b>			
Total Employment (jobs)	(6,043)	(18,380)	(29,242)
Gross Wage Rates (\$ per Worker)	(417)	(1,269)	(2,019)
Investment (\$ millions)	(77)	(235)	(373)
Real Disposable Income (\$ millions)	(616)	(1,873)	(2,981)

In the aggregate, the state's electricity consumers will pay \$1.371 billion in 2015 – within a range of \$841 million and \$2.122 billion – due to the RPS. Over the period of 2011 to 2020, the state RPS will cost \$11.778 billion, within a range of \$6.412 billion and \$18.520 billion. Colorado's electricity prices will increase in 2015 by an average of 3.75 cents per kilowatt-hour

<sup>5</sup> Detailed information about the STAMP<sup>®</sup> model can at [http://www.beaconhill.org/STAMP\\_Web\\_Brochure/STAMP\\_HowSTAMPworks.html](http://www.beaconhill.org/STAMP_Web_Brochure/STAMP_HowSTAMPworks.html).

(kWh), or by 40 percent, within a range of 1.23 cents per kWh, or by 13 percent, and 5.97 cents per kWh, or by 64 percent.

These higher energy prices will hurt Colorado's households and businesses and, in turn, inflict significant harm on the state economy. The BHI model suggests that by 2015 the Colorado economy will lose an average of 18,380 jobs, within a range of between 6,043 jobs under our low cost scenario and 29,242 jobs under our high cost scenario. We report net employment losses that include jobs that would be created to build out renewable electricity power plants and infrastructure under each cost scenario. The lower portion of Table 1 presents our estimates of the effects of the RPS in 2010 Net Present Value dollars (NPV).

The decrease in labor demand – as seen in the job losses – will trigger gross wages to fall. In 2015 the RPS mandate will reduce annual wages by an average of \$1,269 per worker, within a range of between \$417 per worker and \$2,019 per worker. 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 goods and services such as groceries, entertainment, dining out and personal services such as haircuts. In 2015 annual real disposable income will fall by \$1.873 billion, within a range of \$616 million and \$2.981 billion.

Annual investment will fall by \$235 million, within a range of \$77 million and \$373 million under our low and high cost cases respectively. As with employment, the investment losses will be tempered by the investments required in building renewable power plants, transmission lines and reconfigurations to the electricity grid.

Table 2 shows how the RPS will affect the annual electricity bills of households and businesses in Colorado. In 2020 the RPS will cost families an average of \$337 per year; commercial businesses an average of \$2,360 per year; and industrial businesses on average \$43,367 per year. Over the next 10 years the average household ratepayer will pay \$1,474 in higher electricity costs; the average commercial ratepayer will spend an extra \$10,332; and the average industrial ratepayer an extra \$189,879.

**Table 2: Effects of RPS on Electricity Ratepayers in 2020 (2010 \$)**

	Low	Medium	High
<b>Cost in 2020</b>			
Residential Ratepayer (\$)	111	337	536
Commercial Ratepayer (\$)	776	2,360	3,754
Industrial Ratepayer (\$)	14,258	43,367	68,996
<b>Total Over Period (2011-2020)</b>			
Residential Ratepayer (\$)	809	1,474	2,317
Commercial Ratepayer (\$)	5,667	10,332	16,239
Industrial Ratepayer (\$)	104,144	189,879	298,439

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. As a result, a recent study found that wind power actually increases pollution and greenhouse gas emissions.<sup>6</sup> Thus there are, in fact, no benefits of implementing RPS policies based on heavy uses of wind.

Also firms with high electricity usage will likely move their production and emissions out of Colorado to locations with lower electricity prices. Therefore the Colorado policy will not reduce global emissions, but rather send jobs and capital investment outside the state. As a first step, Colorado policymakers should repeal the expansions to the voter mandated RPS before electricity costs spiral out of control. In addition legislators should demand that future environmental policies be subject to a process of regular and rigorous analysis of their environmental effects, costs, benefits, and economic impacts.

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<sup>6</sup> See “How Less Became More: Wind, Power and Unintended Consequences in the Colorado Energy Market,” Bentek Energy, LLC. (Evergreen Colorado: May, 2010).

## Introduction

Combined with fluctuations in fossil fuel prices, the push to mitigate the adverse effects of climate change has encouraged many state governments to respond with public policy initiatives designed to promote the use of alternative energy sources.

Colorado voters approved a state Renewable Portfolio Standard (RPS) in 2004, and the House expanded it to its current form in 2010 by imposing some of the nation's most demanding standards on electric utilities. House Bill 1001 requires utilities to use specific levels of renewable energy in their electricity generation: 5 percent for the years 2008 -2010; 12 percent for 2011 - 2014; 20 percent for 2015-2019; and 30 percent by 2020.

The Bills also contain measures to control costs for retail customers, by limiting the RPS costs that utilities can pass to customers to "two percent of the total electric bill annually for each customer."<sup>7</sup> But this provision only covers the incremental costs, referred to as the Renewable Energy Standard Adjustment on utility bills. The Electric Commodity Adjustment (ECA) fee is not subject to the 2 percent cap and will absorb the rest of the costs, such as backup energy and capital construction. As a result, the cap has no effect on containment of cost increases due to the RPS.<sup>8</sup>

Another component of the Bill – the banking of unused renewable energy credits – helps defray costs initially. By producing more renewable energy than required by law in the first few years of the 5 percent RPS requirement, producers can 'bank' these extra units, to reduce the required number of units required in the future, when the mandate increases.

The statute defines renewable energy sources to include only solar, wind, small-scale hydropower, geothermal, hydrogen derived from renewable sources, and certain forms of biomass energy. Large-scale hydroelectric generation is specifically excluded as a form of "renewable" power.

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. Thus, producers of renewable energy seek to guarantee a market through RPS legislation. Unfortunately this guarantee will be very costly for ratepayers.

In order to keep the voltage of 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

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<sup>7</sup> Ibid. HB1001, 8.

<sup>8</sup> Competitive Enterprise Institute, "Colorado's Great Green Deception," <http://cei.org/sites/default/files/William%20Yeatman%20and%20Amy%20Oliver%20Cooke%20-%20Colorado%27s%20Great%20Green%20Deception.pdf>.

(which trips a shutdown mechanism in commercial windmills), another power source must be ramped up instantly.

Increases in electricity costs are known to have a profound negative effect on the economy not unlike taxes, as prosperity and economic growth are dependent upon access to reliable and affordable energy. Since electricity is an essential commodity, consumers will have limited opportunity to avoid these costs. For the poorest members of society these energy taxes will compete directly with essential purchases in the household budget, such as food, transportation and shelter.

For this report the American Tradition 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<sup>®</sup> models (State Tax Analysis Modeling Program) to estimate the economic effects of the state RPS mandate.

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.

A literature review shows the EIA projected costs to be 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. EIA does not take into account the actual experience of existing renewable electricity power plants. Therefore we provide three estimates of the cost of Colorado's RPS mandates: low, average and high, using different cost and capacity factors estimates for electricity generating technologies from the academic literature. A forthcoming Appendix of this report will contain a detailed discussion of other projections for Levelized Energy Cost (LEC), capacity factors and other issues that would increase the costs of so-called renewable electricity generating sources.

## **Estimates and Results**

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 Colorado RPS mandate using low, average and high cost estimates 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 forthcoming Appendix contains details of our methodology. Table 3 displays our estimates of the cost and economic impact of the RPS mandate on the state.

**Table 3: The Cost of the RPS Mandate on Colorado (2010 \$)**

<b>Costs Estimates</b>	<b>Low</b>	<b>Medium</b>	<b>High</b>
Total Net Cost in 2020 (\$ millions)	940	2,858	4,547
Total Net Cost 2011-2020 (\$ millions)	6,412	11,778	18,520
Electricity Price Increase in 2020 (cents per kWh)	1.23	3.75	5.97
Percentage Increase	12%	37%	58%
<b>Economic Indicators (2020)</b>			
Total Employment (jobs)	(6,043)	(18,380)	(29,242)
Gross wage rates (\$ per Worker)	(417)	(1,269)	(2,019)
Investment (\$ millions)	(77)	(235)	(373)
Real Disposable Income (\$ millions)	(616)	(1,873)	(2,981)

The RPS will impose costs of \$2.858 billion in 2020, within a range of \$940 million and \$4.547 billion. For the period of 2011 – 2020 the RPS mandate will cost \$11.78 billion with a low estimate of \$6.41 billion and a high estimate of \$18.52 billion. As a result the RPS mandate will increase electricity prices by 3.75 cents per kilowatt-hour (kWh) or by 37 percent, within a range of 1.23 cents per kWh, or by 12 percent, and 5.97 cents per kWh, or by 58 percent.<sup>9</sup>

The STAMP model simulation indicates that upon full implementation the RPS law will harm the state economy. Colorado'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 2020 the Colorado economy will shed 18,380 jobs, within a range of 6,043 and 29,242 jobs.

The decrease in labor demand – as seen in the job losses – will cause gross wages to fall. In 2020 the 15 percent mandate will reduce annual wages by \$1,269 per worker, with the low cost case producing a \$417 wage drop and the high cost case will reduce wages by \$2,019 per worker.

The job losses and price increases will reduce real incomes as firms, households and governments spend more of their budgets on electricity and less on other items, such as home goods and services. In 2020 annual real disposable income will fall by \$1.873 billion, and by \$616 million and by \$2.981 billion under the low and high cost scenarios respectively.

<sup>9</sup> Based on a price of 7.3 cents per kWh for 2015 from the U.S. Department of Energy, Energy Information Agency, Annual Energy Outlook 2010, Table 8: Electricity Supply, Disposition, Prices, and Emissions, Colorado [http://www.eia.doe.gov/oiaf/aeo/aeoref\\_tab.html](http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html). Using compound growth rate from 1990 - 2008 projected retail sales of 16,903 (thousand MWhs) divided by retail sales of \$1.227 billion.

Furthermore annual net investment in 2020 will fall by \$235 million, within a range of \$77 million and \$373 million. The investment losses are tempered by the investments required in building renewable power plants, transmission lines and reconfigurations to the national electricity grid.

## Conclusion

House Bill 1001, which increased and pulled forward the percent requirements for Colorado's RPS, states that

“...when evaluating electric resources acquisitions, the commission shall consider, on a qualitative basis, factors that affect employment and the long-term economic viability of Colorado communities.”<sup>10</sup>

Unfortunately the House did not heed its own advice and neglected to perform a quantitative cost-benefit analysis on the long term economic viability of expanding its RPS for the state of Colorado. When creating and implementing a state-level Renewable Portfolio Standard that inevitably forces state residents to pay premiums on their electricity, the costs are borne by state ratepayers, while the majority of benefits are reaped by those outside the state. Moreover, by limiting the scope of renewable energy to not include all hydroelectricity, the RPS becomes less of an energy policy and more of a targeted handout to specific industries.

Contrary to the claims of RPS enthusiasts, current forms of renewable energy — solar and wind in particular — are more costly and less reliable than conventional sources, while other sources such as large hydroelectric plants are not deemed renewable enough. 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 and will certainly raise electricity prices for consumers and businesses in Colorado. Moreover the environmental benefits of wind power are a mirage due to the necessity of keeping backup power generation sources online and available to cycle-up when the wind power is unavailable.

Meanwhile the Colorado business community will see a reduction in its competitive advantage over the 19 states that have not adopted similar legislation.<sup>11</sup> The result is that Colorado will face slower growth in disposable income, employment and wages and an increase in electricity rates compared to a baseline of no RPS.

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<sup>10</sup>Colorado General Assembly, HB 1281, “Concerning Increased Renewable Energy Standards,” [http://www.leg.state.co.us/CLICS/CLICS2010A/csl.nsf/fsbillcont3/47C157B801F26204872576AA00697A3F?Open&file=1001\\_enr.pdf](http://www.leg.state.co.us/CLICS/CLICS2010A/csl.nsf/fsbillcont3/47C157B801F26204872576AA00697A3F?Open&file=1001_enr.pdf).

<sup>11</sup>U.S. Department of Energy, Energy Efficiency and Renewable Energy, EERE State Activities and Partnerships, States with Renewable Portfolio Standards, [http://apps1.eere.energy.gov/states/maps/renewable\\_portfolio\\_states.cfm](http://apps1.eere.energy.gov/states/maps/renewable_portfolio_states.cfm) (accessed January 20, 2011).

## 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*.<sup>12</sup> 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 4 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 costs 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.

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<sup>12</sup> 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](http://www.eia.doe.gov/oiaf/aeo/electricity_generation.html), (accessed September 20, 2010).

**Table 4: 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.<sup>13</sup> As a result capital and other costs are more likely to rise than fall over the next two decades.

Table 4 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.<sup>14</sup> 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

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<sup>13</sup> MetalPrices.com, "LME Aluminum Price Charts,"

<http://www.metalprices.com/FreeSite/metals/al/al.asp#MoreCharts> (accessed January 2011).

<sup>14</sup> 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](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.<sup>15</sup> 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.<sup>16</sup>

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.<sup>17</sup> According to the EIA's own reporting from 137 current wind power plants in 2003, the average capacity factor was 26.9 percent.<sup>18</sup> In addition, a recent analysis of wind capacity factors around the world finds an actual average capacity factor of 21 percent.<sup>19</sup> Moreover, other estimates find capacity factors in the mid teens and as low as 13 percent.<sup>20</sup>

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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<sup>15</sup> Tom Hewson and Dave Pressman, "Renewable Overload: Waxman-Markey RES Creates Land-use Dilemmas," *Public Utilities Fortnightly* 61 (August 1, 2009).

<sup>16</sup> "Evidence to the House of Lords Economic Affairs Committee Inquiry into 'The Economics of Renewable Energy'," Memorandum by Dr. Phillip Bratby, May 15, 2008.

<sup>17</sup> Nicolas Boccard, "Capacity Factors for Wind Power: Realized Values vs. Estimates," *Energy Policy* 37, no. 7 (July 2009): 2680.

<sup>18</sup> Cited by Tom Hewson, Energy Venture Analysis, "Testimony for East Haven Windfarm," January 1, 2005, <http://www.windaction.org/documents/720> (accessed December 2010).

<sup>19</sup> Boccard.

<sup>20</sup> 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 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.<sup>21</sup> 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.<sup>22</sup> 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 these markets.

### *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 Colorado 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 project its growth through 2020 using its historical compound annual growth rate (3.6 percent).<sup>23</sup> To these totals, we apply the percentage of renewable sales prescribed by the Colorado RPS. By 2020, renewable energy sources must account for 30 percent of total electricity sales in Colorado.

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<sup>21</sup> Biomass Energy Basics, National Renewable Energy Laboratory, Biomass Basics, [http://www.nrel.gov/learning/re\\_biomass.html](http://www.nrel.gov/learning/re_biomass.html) (accessed December, 2010)

<sup>22</sup> Hewson, 61.

<sup>23</sup> U.S. Department of Energy, Energy Information Agency, Colorado 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/colorado.html](http://www.eia.doe.gov/cneaf/electricity/st_profiles/colorado.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 2020 as a proxy to grow renewable sources for Colorado. We used the growth rate of these projections to estimate Colorado's renewable generation through 2020 absent the RPS.<sup>24</sup>

**Table 5: Projected Electricity Sales, Projected Renewables and RPS Renewables Required**

Year	Projected Electricity Sales MWhs (000s)	Eligible Renewable MWhs (000s)	RPS Requirement MWhs (000s)	Difference MWhs (000s)
2011	57,288	3,579	6,875	926*
2012	59,120	5,121	7,094	1,973
2013	61,014	5,121	7,322	2,200
2014	62,972	5,121	7,557	2,435
2015	64,996	5,121	12,999	7,878
2016	67,089	5,121	13,418	8,297
2017	69,253	5,121	13,851	8,729
2018	71,491	5,121	14,298	9,177
2019	73,806	5,121	14,761	9,640
2020	76,199	5,121	22,860	17,738
<b>Total</b>	<b>663,228</b>	<b>49,671</b>	<b>121,034</b>	<b>68,993</b>

\*adjusted down by 2,370,000 MWhs to reflect the use of banked credits.

We subtracted our baseline projection of renewable sales from the RPS-mandated quantity of sales for each year from 2011 to 2020 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 (2011 to 2020). 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 5 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

<sup>24</sup> U.S. Department of Energy, Energy Information Agency, *Annual Energy Outlook 2010*, "Table 99: Renewable Electricity Generation by Fuel," [http://www.eia.doe.gov/oiaf/archive/aeo10/aeoref\\_tab.html](http://www.eia.doe.gov/oiaf/archive/aeo10/aeoref_tab.html) (accessed December 2010).

the electricity.<sup>25</sup> 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.<sup>26</sup> 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 6 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.

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<sup>25</sup> 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](http://www.eia.doe.gov/oiaf/aeo/electricity_generation.html) (accessed September 2010).

<sup>26</sup> For coal, gas and nuclear generation we used the production cost estimates from the International Energy Agencies, Energy Technology Analysis Programs, “Technology Brief E01: Coal 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 Wisser, 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](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 6: LEC and Capacity Factors for Electricity Generation Technologies**

	Capacity Factor (percent)	Total Production Cost (cents/MWh)		
		2010	2020	2025
<b>Coal</b>				
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
<b>Gas</b>				
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
<b>Nuclear</b>				
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
<b>Biomass</b>				
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
<b>Wind</b>				
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

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.

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. With coal, for example, we

multiplied the avoided amount generation of electricity from coal (12.809 million MWhs in 2020) by the LEC of coal (\$85.21 per MWh) and then by the difference between the capacity factor of coal and the weighted average (using MWhs as weights) capacity factor 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 Colorado represents the net cost of the RPS. Tables 7, 8 and 9 display the results of our Average, Low and High Cost calculations respectively.

**Table 7: Average Cost Case of RPS Mandate from 2011 to 2020**

Year	Gross Cost (2010 \$000s)	Less Conventional (2010 \$000s)	Total (2010 \$000s)
2011	186,111	24,930	161,181
2012	396,832	53,433	343,399
2013	442,542	59,600	382,942
2014	489,799	65,965	423,835
2015	1,584,440	213,388	1,371,052
2016	1,668,634	224,727	1,443,907
2017	1,755,689	236,451	1,519,238
2018	1,845,708	248,575	1,597,133
2019	1,938,797	261,112	1,677,685
2020	3,339,417	481,714	2,857,702
<b>Total</b>	<b>13,647,970</b>	<b>1,869,896</b>	<b>11,778,075</b>

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 2020 under the average cost scenario above, we divided \$2,857 million into 76,199 million kWhs for a cost of 3.75 cents per kWh.

**Table 8: Low Cost Case of RPS Mandate from 2011 to 2020**

Year	Gross Cost (2010 \$000s)	Less Conventional (2010 \$000s)	Total (2010 \$000s)
2011	138,416	39,156	99,261
2012	294,616	83,922	210,695
2013	328,553	93,635	234,918
2014	363,637	103,633	260,004
2015	1,176,321	335,241	841,080
2016	1,238,829	353,055	885,773
2017	1,303,460	371,475	931,985
2018	1,370,293	390,522	979,771
2019	1,439,404	410,218	1,029,186
2020	1,718,876	779,323	939,553
<b>Total</b>	<b>9,372,405</b>	<b>2,960,179</b>	<b>6,412,226</b>

**Table 9: High Cost Case of RPS Mandate from 2011 to 2020**

Year	Gross Cost (2010 \$000s)	Less Conventional (2010 \$000s)	Total (2010 \$000s)
2011	264,731	15,777	248,954
2012	565,327	33,814	531,513
2013	630,447	37,721	592,725
2014	697,769	41,750	656,019
2015	2,257,195	135,055	2,122,140
2016	2,377,137	103,526	2,273,611
2017	2,501,157	108,928	2,392,229
2018	2,629,398	114,513	2,514,886
2019	2,762,013	120,288	2,641,725
2020	4,759,625	213,093	4,546,533
<b>Total</b>	<b>19,444,798</b>	<b>924,464</b>	<b>18,520,334</b>

## *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.<sup>27</sup> 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.<sup>28</sup>

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 8,977 kWhs of electricity in 2020 and we expect the high cost scenario to raise electricity costs by 3.75 cents per kWh in the same year in our average cost case. Therefore we expect residential ratepayers to pay an additional \$336.67 in 2020.

## *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 Colorado 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

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<sup>27</sup> U.S. Department of Energy, Energy Information Administration, "Average electricity consumption per residence in CO 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.

<sup>28</sup> 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](http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html). (accessed December 22, 2010).

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.<sup>29</sup>

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 possibly 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.<sup>30</sup> We inflated the sales data (dollars and MWhs) through 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 retail 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 2020 for our high cost case we divided our average price of 10.246 cents per kWh by our estimated price increase of 5.966 cents per kWh for a price increase of 58.23 percent.

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 states' economies. We then averaged the percent changes together to determine the average elasticity of the three utility increases. Table 10 displays these elasticities, which were then applied to the calculated percent change in electricity costs for the state of Colorado discussed above.

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<sup>29</sup> 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).

<sup>30</sup> U.S. Department of Energy, Energy Information Agency, Colorado 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/colorado.html](http://www.eia.doe.gov/cneaf/electricity/st_profiles/colorado.html) (accessed January 2011).

**Table 10: Elasticities for the Economic Variables**

<b>Economic Variable</b>	<b>Elasticity</b>
Employment	-0.022
Gross Wage Rates	-0.063
Investment	-0.018
Disposable Income	-0.022

We applied the elasticities to percentage increase in electricity price and then applied the result to Colorado 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.<sup>31</sup> For example, under our high-cost scenario we multiplied the electricity price increase (58.23 percent) by the employment elasticity (-.021535 percent) and the result by total employment estimated for 2020 (2,292,893) to get our employment estimate of 29,242.

<sup>31</sup> 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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