The Economic Impact of Pennsylvania's Alternative Energy Portfolio Standard

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Executive Summary

In early 2004 Pennsylvania lawmakers started to design a mandatory Renewable Portfolio Standard (RPS). In the negotiations that followed they created the Alternative Energy Portfolio Standard (AEPS). The first tier of the law was similar to many renewable portfolio standards in other states, in that it required that eight percent of energy be produced from sources such as solar, hydro, wind and biomass. The second tier – a 10-percent mandate by the year 2021 – is likely to be almost entirely fulfilled by waste coal, a source considered to be dirtier than many modern coal plants.

The Beacon Hill Institute has applied its STAMP® (State Tax Analysis Modeling Program) to estimate the economic effects of these AEPS mandates. The U.S. Energy Information Administration (EIA), a division of the Department of Energy, provides optimistic estimates of renewable electricity costs and capacity factors. This study bases our estimates on EIA projections. However, we also provide three estimates of the cost of Pennsylvania's AEPS mandates — low, average and high — using different cost and capacity factor estimates for electricity-generating technologies from other academic literature. Our major findings show:

- The current AEPS law will raise the cost of electricity by $2.55 billion for the state's electricity consumers in 2021, within a range of $1.71 billion and $3.24 billion
- Pennsylvania's electricity prices will rise by 11.9 percent by 2021, due to the current AEPS law

These increased energy prices will hurt Pennsylvania's households and businesses and, in turn, inflict significant harm on the state economy. In 2021, the AEPS would:

- Lower employment by an average of 17,380 jobs, within a range of 11,365 jobs and 22,340 jobs
- Reduce real disposable income by $1.66 billion, within a range of $1.085 billion and $2.135 billion
- Decrease investment by $205 million, within a range of $135 million and $260 million
- Increase the average household electricity bill by $170 per year; commercial businesses by an average of $1,125 per year; and industrial businesses by an average of $26,830 per year.

Introduction

Originally drafted in November 2004, the Pennsylvania Alternative Energy Portfolio Standard (AEPS) was based on a Renewable Portfolio Standard (RPS) that required utilities to generate a fixed percentage of electricity from renewable sources.[1] That was not enough, however, and further legislation required that this percentage have specific requirements or "carve outs." The end result was that eight percent of retail sales must come from Tier I renewables, which included a 0.5 percent solar carve out, while an additional 10 percent must come from Tier II renewables.

House Bill 2200 expanded the original act in 2008.[2] The current form included annual step-up provisions. Beginning with a combined 5.7 percent of retail electricity from renewable sources in 2007, Tier I renewables increase by 0.5 percent annually, while Tier II renewables increase less frequently. The year 2010 had a combined cap of 6.7 percent, with escalation to 11.2 percent in 2015, to 15.7 percent in 2020, before it reaches the maximum of 18 percent combined in 2021.

Act 129 of 2008 and a subsequent Final Order in 2009 finalized the breakdown between Tier I and Tier II renewables.[3] Tier I renewables included wind, solar (both thermal and photovoltaic), low-impact hydropower, geothermal, methane gases (from landfills and coal mines), biomass and fuel cells. Tier II resources included waste coal, municipal solid waste, large hydropower and wood byproduct, as well as items that are not actually power sources, such as distributed generation systems, demand-side management and coal gasification technology.[4] According to the Low Impact Hydropower Institute, only one hydropower plant in Pennsylvania has been certified as "low impact" – the Raystown Hydroelectric Project – which accounts for approximately two percent of hydropower in the state.[5]

The Tier I renewables list looks similar to most other state-level renewable portfolio standards, and while more expensive, they do emit less than many conventional energy sources, as we

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[1] Pennsylvania Statutes, Alternative Energy Portfolio Standards Act, 73 P.S. § 1648.1. http://www.dsireusa.org/documents/Incentives/PA06Ra.htm.

[2] The General Assembly of Pennsylvania. House Bill No. 2200, Session of 2008 http://www.legis.state.pa.us/CFDOCS/Legis/PN/Public/btCheck.cfm?txtType=PDF&sessYr=2007&sessInd=0&billBody=H&billTyp=B&billNbr=2200&pn=4526.

[3] Pennsylvania Public Utility Commission. Docket No. M-00051865. http://www.puc.state.pa.us/PcDocs/569133.doc.

[4] Pennsylvania AEPS website; Overview. http://paaeps.com/credit/overview.do.

[5] Low Impact Hydropower Institute. Certified Facilities by state. http://www.lowimpacthydro.org/certified-facilities/?sel=PA.

detail in our Life Cycle Analysis section. Tier II methods include demand-side management, which attempts to change users' electricity consumption (reductions), but it is difficult to quantify how much is due to the policy, and how much would have happened on its own, due to higher costs or more efficient gadgets.

Tier II is the reason that the policy is called an Alternative Energy Portfolio Standard as opposed to a Renewable Portfolio Standard or Renewable Energy Standard. When a coal mine produces coal for delivery, it takes the coal with a high energy-to-weight ratio to ship. Since shipment is costly, value is maximized this way. Waste coal produces energy from mined coal that was determined to have too low of an energy-to-weight ratio to be profitable to ship. In essence this means that to produce the same amount of energy, more fuel must be used, typically releasing more emissions per MWh of energy produced.

In a 2009 paper, just two years after the first requirements, a Pennsylvania Department of Environmental Protection report stated:

> "We already know that sufficient credits from waste coal have been generated to meet the entire Tier II requirements though at least 2021… For the 2007-2008 compliance period, the weighted-average Tier II compliance credit traded for $0.66. This amount is too small to affect plant investment decisions."[6]

By the 2010-2011 compliance period the price had decreased to $0.22, one-third the price in three years, and we foresee it continuing to drop in the future as more credits are produced annually then consumed, creating a massive surplus of credits. In pricing the AEPS, we assume that prices continue to decrease in an exponential fashion until leveling out at five cents per credit. It is likely that the price will fall even further, making this estimate conservative.

A form of cost cap is in effect with the inclusion of an Alternative Compliance Payment. The ACP allows utilities to pay $45 for each megawatt-hour (MWh) that they are short of the cap. The solar carve-out ACP is priced differently at 200 percent of the market value of solar plus

[6] Pennsylvania Final Climate Change Action Plan. December 18, 2009. http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-77736/ALL%20OF%20VOLUME%201%20AND%202.pdf. As seen in www.puc.state.pa.us/electric/electric_alt_energy.aspx.

the "levelized up-front rebates provided to sellers of solar renewable energy credit."[7] In 2011 the price was set at $495.81 per MWh. These prices act as a release valve. In theory, if the cost of producing energy exceeds $45 (or higher for the solar requirement) then ACPs will be purchased, as opposed to the creation of renewable energy.

Another component of the Act – the banking of unused Renewable Energy Credits (RECs) – could help defray costs. By producing more green energy than required by the Act, energy suppliers could bank credits to reduce future requirements. However, the EIA projections made prior to the law show a baseline scenario in which renewable electricity generations will fall below REP minimums. Therefore, we think it is unlikely that producers will supply excess renewable energy to trigger banking. All green energy produced will go towards the requirement that year, and not be banked for future consumption. For this reason, we assume that they will have no effect on overall price of production.

All "reasonable and prudently incurred costs for compliance with the act" may be recovered by the utilities.[8] This means that any ACP payments, purchase of RECs, cost of delivery, or the cost of building and maintaining alternative energy can and will be passed along to the end consumer, be they businesses or individuals.

Since renewable energy generally costs more than conventional energy, many have voiced concerns about higher electric rates. A wide variety of cost estimates exist for renewable electricity sources. The EIA provides estimates for the cost of conventional and renewable electricity generating technologies. However, the EIA's assumptions are optimistic about the capacity of renewable electricity to generate cost-efficient and 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, with the EIA's capacity factor for wind 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 Pennsylvania's AEPS mandate: low, average and high, using different cost and capacity factor estimates for electricity-generating technologies from the academic literature.

One could justify the higher electricity costs if the environmental benefits – in terms of reduced GHG and other emissions – outweighed the costs. However, it is unclear that the use of

[7] PUC Rulemaking Order Docket No. L-00060180. http://www.puc.state.pa.us/PCDOCS/1023111.doc.
[8] Ibid.

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 of wind and solar power. A recent study found that wind power actually increases pollution and greenhouse gas emissions.[9] Thus there appear to be few, if any, benefits to implementing AEPS policies based on heavy uses of wind.

Governments enact AEPS policies because most sources of renewable electricity generation are less efficient and thus more costly than conventional sources of generation. The AEPS policy forces utilities to buy electricity from renewable sources and thus guarantees a market for them. These higher costs are passed on to electricity consumers, including residential, commercial and industrial customers.

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.

In this paper the Beacon Hill Institute at Suffolk University (BHI) estimates the costs of this Act and its impact on the state's economy. To that end, BHI applied its STAMP® (State Tax Analysis Modeling Program) to estimate the economic effects of the state AEPS mandate.[10]

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 Pennsylvania's AEPS 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 counterfactual assumption that the AEPS mandate would not be implemented. The forthcoming Appendix contains details of our methodology.

[9] See "How Less Became More: Wind, Power and Unintended Consequences in the Colorado Energy Market," Bentek Energy, LLC. (Evergreen Colorado: May 2010).
[10] Detailed information about the STAMP® model can at http://www.beaconhill.org/STAMP_Web_Brochure/STAMP_HowSTAMPworks.html.

Table 1 displays the cost estimates and economic impact of the 18 percent AEPS mandate in 2021, compared to a baseline of no AEPS policy.

Table 1: The Cost of the 18 percent AEPS Mandate on Pennsylvania (2012 $)

Costs Estimates	**Low**	**Average**	**High**
Total Net Cost in 2021 ($ m)	1,710	2,550	3,240
Total Net Cost 2013-2021 ($m)	12,335	16,355	20,620
Electricity Price Increase in 2021 (cents per kWh)	0.97	1.45	1.84
Percentage Increase	8.0	11.9	15.2
Economic Indicators (2021)			
Total Employment (jobs)	(11,365)	(17,380)	(22,340)
Investment ($ m)	(135)	(205)	(260)
Real Disposable Income ($ m)	(1,085)	(1,660)	(2,135)

The majority of the negative economic effects come from the Tier I section of the current AEPS, due to the higher-cost nature of renewable energy as opposed to the cheap waste coal credits in Tier II. Overall the AEPS will impose costs of $2.55 billion by 2021, within a range of $1.71 billion and $3.24 billion. As a result the AEPS mandate would increase average electricity prices by 1.45 cents per kilowatt-hour (kWh) or by 11.9 percent, within a range of 0.97 cents per kWh, or by 8 percent, and 1.84 cents per kWh, or by 15.2 percent.

The STAMP simulation indicates, upon full implementation, the AEPS will harm Pennsylvania's economy. The state's ratepayers will face higher electricity prices that will increase their cost of living, which will in turn put downward pressure on households' disposable income. By 2021 the Pennsylvania economy will shed 17,380 jobs, within a range of 11,365 and 22,340 jobs.

The job losses and price increases will reduce real incomes as firms, households and governments spend more of their budgets on electricity and less on other items, such as goods and services. In 2021 real disposable income will fall by an average of $1.66 billion, between $1.085 billion and $2.135 billion under the low and high cost scenarios. Furthermore, net investment will fall by $205 million, within a range of $135 million and $260 million.

Table 2: Annual Effects of AEPS on Electricity Ratepayers (2012 $)

	Low	Medium	High
One Year Cost (2021)			
Residential Ratepayer ($)	115	170	215
Commercial Ratepayer ($)	755	1,125	1,430
Industrial Ratepayer ($)	18,010	26,830	34,110
Total over period (2013-2021)			
Residential Ratepayer ($)	840	1,110	1,400
Commercial Ratepayer ($)	5,560	7,360	9,280
Industrial Ratepayer ($)	132,725	175,725	221,495

Table 2 shows how the AEPS affects the annual electricity bills of households and businesses in Pennsylvania. In 2021 the AEPS will cost families an average of $170 per year; commercial businesses $1,125 per year; and industrial businesses $26,830 per year. Between 2013 and 2021, the average residential consumer can expect to pay $1,110 more for electricity; a commercial ratepayer would pay $7,360 more; and the typical industrial user would pay $175,725 more.

Emissions: Life Cycle Analysis

One could justify the higher electricity costs if the environmental benefits – in terms of reduced GHG and other emissions – outweighed the costs. Up to this point we calculated the costs and economic effects of requiring more renewable energy in the state of Pennsylvania. The following section conducts a Life Cycle Analysis (LCA) of renewable energy and the total effect that the state AEPS law is likely to have on Pennsylvania's emissions.

The burning of fossil fuels to generate electricity produces emission of gases such as carbon dioxide (CO_2), sulfur oxides (SO_x) and nitrogen oxides (NO_x). These gases are found to negatively affect human respiratory health and the environment (SO_x and NO_x) or contribute to global warming (NO_x and CO_2).

Many proponents of renewable energy (such as wind power, solar power and municipal solid waste) justify the higher electricity prices – and the negative economic effects that follow – based on the claim that these sources produce no emissions (see examples below). But this is misleading. The fuel that powers these services, such as the sun and wind, create no emissions. However the process of construction, operation and decommissioning of renewable power plants does create emissions. This presents the question:

Is renewable energy production as environmentally friendly as some proponents claim?

> "Harnessing the wind is one of the cleanest, most sustainable ways to generate electricity. Wind power produces no toxic emissions and none of the heat trapping emissions that contribute to global warming."[11]
>
> "Wind turbines harness air currents and convert them to emissions-free power."[12]
>
> ~Union of Concerned Scientists
>
> "As far as pollution…Zip, Zilch, Nada… etc. Carbon dioxide pollution isn't in the vocabulary of solar energy. No emissions, greenhouse gases, etc."[13]
>
> ~"Let's Be Grid Free," Solar Energy Facts

The affirmative argument is usually based on the environmental effects of the operational phase of the renewable source (that will produce electricity with no consumption of fossil fuel and no emissions) excluding the whole manufacturing phase (from the extraction to the erection of the turbine or solar panel, including the production processes and all the transportation needs) and the decommission phase. LCA offers a framework to provide a more complete answer to the question.

LCA is a "cradle-to-grave" approach for assessing industrial systems. LCA begins with the gathering of raw materials from the earth to create the product and ends at the point when all materials are returned to the earth. By including the impacts throughout the product life cycle, LCA provides a comprehensive view of the environmental aspects of the product or process and a more accurate picture of the true environmental trade-offs in product and process selection. Table 3 displays LCA results for conventional and sources.

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[11] How Wind Energy Works. Union of Concerned Scientists. http://www.ucsusa.org/clean_energy/our-energy-choices/renewable-energy/how-wind-energy-works.html.
[12] Our Energy Choices: Renewable Energy. Union of Concerned Scientists. http://www.ucsusa.org/clean_energy/our-energy-choices/renewable-energy/.
[13] Solar Energy Facts. Let's Be Grid Free. http://www.letsbegridfree.com/solar-energy-facts/.

Table 3: Emissions by Source of Electricity Generation (Grams/kWh)

Phase	Emission	Coal	Gas	Wind	Nuclear	Solar	Biomass
Construction and Decommission	CO_2	2.59	2.20	6.84	2.65	31.14	0.61
	NO_x	0.01	0.01	0.06	0.00	0.12	0.00
	SO_x	0.06	0.05	0.02	0.00	0.14	0.00
Production and Operation	CO_2	1,022.00	437.80	0.39	1.84	0.27	58.60
	NO_x	3.35	0.56	0.00	0.00	0.02	5.34
	SO_x	6.70	0.27	0.00	0.01	0.00	2.40
Total	CO_2	1,024.59	440.00	7.23	4.49	31.42	59.21
	SO_x	3.36	0.57	0.06	0.01	0.14	5.34
	NO_x	6.76	0.32	0.02	0.01	0.14	2.40

Coal and gas produce significantly more emissions of all three gases than all the other technologies. Nuclear and wind produces the least emissions of the nonconventional types, with solar and biomass significantly higher due to construction and decommission for solar and production and operations for biomass. However, the construction and decommission phases of wind and solar produce non-trivial levels of emissions, with solar several factors higher than the others. Nevertheless, LCA analysis shows that wind, nuclear, solar and biomass produce significantly less emissions than coal and gas.

While waste coal makes up the entirety of the Tier II requirements in our AEPS projections, the extremely low, and quickly decreasing, weighted average price for a Tier II credit means that very few, if any, additional MWhs are being produced compared to a baseline due to the policy. For this reason our emission calculation does not include any increases or decreases due to waste coal.

However this LCA analysis is incomplete. The analysis shows that wind and solar technologies derive benefits from their ability to produce electricity with no consumption of fossil fuels and subsequent pollution without adequately addressing the intermittency of these technologies. These intermittent technologies cannot be dispatched at will and, as a result, require reliable back-up generation running —idling per se —in order to keep the voltage of the electricity grid in equilibrium. For example, if the wind dies down, or blows too hard (which trips a shutdown mechanism in commercial windmills), another power source must be ramped up (or cycled) instantaneously. Therefore new wind and solar generation plants do not replace any dispatchable generation sources.

This cycling of coal and (to a much lesser extent) gas plants causes them to run inefficiently and produce more emissions than if the intermittent technologies were not present. A recent study found that wind power could actually increase pollution and greenhouse gas emissions in areas that generate a significant portion of their electricity from coal.[14] The current LCA literature ignores this important portion of the analysis, which provides a distorted assessment of wind and solar power.

Nevertheless renewable sources – in and of themselves – emit much less than conventional sources, displacing only a small amount of emissions from conventional sources. Indeed, this amount is multiplied, due to lower capacity ratings of many green energy sources and required back up generation.

To better judge the actual total benefit derived from switching from the current energy source portfolio to one that involves more renewable energy, as the AEPS dictates in Pennsylvania, BHI compared the total emissions impact according to our projections using a life cycle analysis for the various energy sources. Table 4 on page 11 displays the results.

Table 4: Change in Emissions Due to the Pennsylvania AEPS Mandates (‘000 metric tons)

Emission Gas	2021	Total 2013-2021
No Capacity Factor Differences		
Carbon Dioxide	(6,265)	(36,785)
Sulfur Oxide	(1.7)	(7.3)
Nitrogen Oxide	(31)	(184)
Capacity Factor Differences		
Carbon Dioxide	(1,915)	(11,235)
Sulfur Oxide	11	70
Nitrogen Oxide	(5)	(30)

The AEPS mandate reduces emissions of CO_2 by 1.9 million metric tons in 2021, with a total reduction of 11.2 million tons between 2013 and 2021. If no back up capacity was required due to the intermittency issues of renewables, then the reduction would be more than three times as much, due mainly to our projection of Pennsylvania’s reliance on biofuels to cover a sizeable portion the AEPS.

[14] See “How Less Became More: Wind, Power and Unintended Consequences in the Colorado Energy Market,” Bentek Energy, LLC. (Evergreen Colorado: May, 2010).

Conclusion

With the Pennsylvania Alternative Energy Portfolio Standard, as with many renewable energy policies, elected politicians told their supporters that the policies would bring both environmental and economic rewards. As former Pennsylvania Governor Ed Rendell, signer of the bill, said:

> "Cleaner, more advanced energy has its own rewards, in terms of both the environmental benefits it brings and the economic opportunities it promises."[15]

#

Undoubtedly there will be reductions in emissions due to the replacement of conventional energy with renewable sources, although less than many proponents claim, due to the intermittency of many renewables. But the governor and other supporters of the policy are disingenuous by touting the economic opportunities. New plants will be built, creating the opportunities that he suggested. But as we have shown, there will be many more lost opportunities.

These supporters commit the broken window fallacy. By requiring utilities to forgo lower cost sources of conventional energy, and instead use high-cost "green energy," supporters of the Act might be able to point to individual investment projects and jobs. However, the important consideration should be the net economic effects of the mandate. The lost jobs that will be lost due to higher energy costs are not as easy to identify, but they are just as important.

Moreover in their zeal to micromanage the issue, as opposed to a broad-based implementation that would allow the market to decide the most efficient ways to implements alternative energy, lawmakers created a two-tier system that in essence increases the cost of providing electricity without changing much about the actual production. While the Alternative Energy Portfolio Standard might generate small economic benefits, Pennsylvania electricity ratepayers will pay higher rates, face fewer employment opportunities, and watch investment flee to other states with more favorable business climates.

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[15] Pittsburgh Business Times. Gov. Rendell wants 'clean' power. December 7, 2004. http://www.bizjournals.com/pittsburgh/stories/2004/12/06/daily23.html.

Firms with high electricity usage will likely move their production, and emissions, out of Pennsylvania to locations with lower electricity prices. Therefore the Pennsylvania policy will not reduce global emissions, but rather send jobs and capital investment outside the state.

Appendix

Electricity Generation Costs

As noted above, governments enact AEPS policies because most sources of renewable electricity generation are less efficient and thus more costly than conventional sources of generation. AEPS policies force utilities to buy electricity from renewable sources and thus guarantee a market for the renewable sources. These higher costs are passed to electricity consumers, including residential, commercial and industrial customers.

The U.S. Department of Energy's Energy Information Administration (EIA) estimates the Levelized Energy Cost (LEC), or financial breakeven cost per MWh, to produce new electricity in its *Annual Energy Outlook*.[16] 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 5 on the following page shows the EIA projects that the LEC for all four electricity sources (coal, gas, nuclear and wind) will fall significantly from 2016 to 2035. The fall in capital costs drives the drop in total system LEC over the period.

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 38.7 percent and solar by 53.5 percent over the period. These compare to much more modest cost reductions of 5.2 percent for coal, an increase of 14.2 percent for gas, and a drop of 22.1 percent for nuclear over the same period. EIA does provide overnight capital costs for renewable technologies under a

[16] U.S. Department of Energy, Energy Information Administration, *2016 Levelized Cost of New Generation Resources from the Annual Energy Outlook 2011* (2008/$MWh), http://www.eia.doe.gov/oiaf/aeo/electricity_generation.html, (accessed February, 2012).

"high cost" scenario. However, for each renewable technology the EIA "high cost" scenario projects capital costs to drop between 2015 and 2035.

Table 5: Levelized Cost of Electricity from Conventional and Renewable Sources (2009 $/MWh)

Plant Type	Capacity Factor	Levelized Capital Costs	Fixed O&M	Variable O&M (with fuel)	Transmission Investment	Total Levelized Cost
Coal - 2016	0.85	65.3	3.9	24.3	1.2	94.8
2020		75.84	7.9	25.1	1.2	110.0
2035		55.4	7.9	25.4	1.19	89.8
Gas - 2016	0.87	17.5	1.9	45.6	1.2	66.1
2020		18.4	1.89	46.7	1.2	68.2
2035		13.5	1.89	59.0	1.2	75.5
Nuclear -2016	0.9	90.1	11.1	11.7	1	113.9
2020		89.1	11.1	12.3	1	113.5
2035		62.3	11.1	14.3	1	88.7
Wind - 2016	0.344	83.9	9.6	0	3.5	97.0
2020		86.4	9.5	0	3.4	99.2
2035		71.4	9.9	0	3.6	84.9
Solar PV - 2016	0.217	194.6	12.1	0	4	210.7
2025						142.0
2035						98.0
Biomass -2016	0.83	55.3	13.7	42.3	1.3	112.5
2025						88.0
2035						69.0
Hydro -2016	0.514	74.5	3.8	6.3	1.9	86.4
2025						69.0
2035						55.0

Table 5 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 aspect 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.[17] 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 power plants will likely have 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 AEPS 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 AEPS 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, but 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 AEPS mandates and a 20 percent federal mandate by 2025.[18] 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.[19]

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[17] 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.
[18] Tom Hewson and Dave Pressman, "Renewable Overload: Waxman-Markey RES Creates Land-use Dilemmas," *Public Utilities Fortnightly* 61 (August 1, 2009).
[19] "Evidence to the House of Lords Economic Affairs Committee Inquiry into 'The Economics of Renewable Energy'," Memorandum by Dr. Phillip Bratby, May 15, 2008.

The need for large areas of land to site 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 wind projects. The new wind capacity will be developed in increasingly 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.[20] According to the EIA's own reporting from 137 current wind power plants in 2003, the average capacity factor was 26.9 percent.[21] In addition, a recent analysis of wind capacity factors around the world finds an actual average capacity factor of 21 percent.[22] Other estimates find capacity factors in the mid-teens and as low as 13 percent.[23]

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

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

[21] Cited by Tom Hewson, Energy Venture Analysis, "Testimony for East Haven Windfarm," January 1, 2005, http://www.windaction.org/documents/720 (accessed December 2011).

[22] Boccard.

[23] See "The Capacity Factor of Wind, Lightbucket," http://lightbucket.wordpress.com/2008/03/13/the-capacity-factor-of-wind-power/, (accessed December 2011) and National Wind Watch, FAQ, http://www.wind-watch.org/faq-output.php (accessed December 2011).

include food crops, grassy and woody plants, residues from agriculture or forestry, oil-rich algae, and the organic component of municipal and industrial wastes.[24] 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 AEPS mandates and a 20 percent federal AEPS in 2025.[25] 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,[26] and also to the struggle facing international aid organizations that address hunger in places such as the Darfur region of Sudan.[27] 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 AEPS, BHI used data from the Energy Information Administration (EIA), a division of the U.S. Department of Energy, to determine the percent increase in utility costs that Pennsylvania 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 2010 and projected its growth through 2025 using its historical compound annual growth rate (3.6

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[24] Biomass Energy Basics, National Renewable Energy Laboratory, Biomass Basics, http://www.nrel.gov/learning/re_biomass.html (accessed December, 2010).
[25] Hewson, 61.
[26] Heather Stewart, "High Costs of Basics Fuels Global Food Fights," The Observer (U.K.), Feb. 17, 2007 http://www.guardian.co.uk/business/2007/feb/18/theobserver.observerbusiness3
[27] Celia W. Dugger, "As Prices Soar, U.S. Food Aid Buys Less," *New York Times*, Sept. 29, 2007 http://www.nytimes.com/2007/09/29/world/29food.html

percent).[28] To these totals, we applied the percentage of renewable sales prescribed by the Pennsylvania AEPS. By 2021, renewable energy sources must account for 15 percent of total electricity sales in Pennsylvania.

Next we projected the growth in renewable sources that would have taken place absent the AEPS. We used an average of the EIA's projection of renewable energy sources by fuel for the SERC Reliability Corporation/Gateway and the Southwest Power Pool/North areas through 2025 as a proxy to grow renewable sources for Pennsylvania. We used the growth rate of these projections to estimate Pennsylvania's renewable generation through 2025 absent the AEPS.[29]

We subtracted our baseline projection of renewable sales from the AEPS-mandated quantity of sales for each year from 2011 to 2025, to obtain our estimate of the annual increase in renewable sales induced by the AEPS in megawatt hours (MWhs). The AEPS mandate exceeds our projected renewables in all years (2013 to 2025). This figure also represents the maximum number of MWhs of electricity from conventional sources that are avoided, or not generated, through the AEPS mandate. We will revisit this shortly. Table 6 on the following page contains the results.

[28] U.S. Department of Energy, Energy Information Administration, Pennsylvania Electricity Profile 2010, "Table 5: Electric Power Industry Generation by Primary Energy Source, 1990 through 2008," http://www.eia.gov/electricity/state/. (accessed January 25, 2011)

[29] U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2010,* "Table 99: Renewable Electricity Generation by Fuel," http://www.eia.doe.gov/oiaf/archive/aeo10/aeoref_tab.html (accessed December 2010).

Table 6: Projected Electricity Sales, Renewable Sales and 15 Percent AEPS Requirement

Year	Projected Electricity Sales MWhs (000s)	Projected Renewable MWhs (000s)	AEPS Requirement MWhs (000s)	Difference MWhs (000s)
2013	155,692	4,674	15,881	11,207
2014	158,035	4,771	16,910	12,139
2015	160,430	5,188	17,968	12,780
2016	162,878	5,243	22,314	17,071
2017	165,380	5,441	23,484	18,043
2018	167,937	5,630	24,687	19,057
2019	170,551	5,547	25,924	20,377
2020	173,223	5,457	27,196	21,739
2021	175,955	5,427	31,672	26,244
Total	**1,490,080**	**47,378**	**206,035**	**158,657**

To estimate the cost of producing the additional extra renewable energy under an AEPS against the baseline, we used estimates of the LEC, or financial break-even cost per MWh, to produce the electricity.[30] 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.[31] We used these alternative figures to calculate

[30] U.S. Department of Energy, Energy Information Administration**,** *2016 Levelized Cost of New Generation Resources from the Annual Energy Outlook 2011* (2009/$MWh), http://www.eia.doe.gov/oiaf/aeo/electricity_generation.html (accessed February 2012).

[31] 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.iea-etsap.org/web/Supply.asp (accessed February 2012). 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,

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 7 below 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.

Table 7: 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	81.11	87.43	81.72
High	85.0	94.80	110.03	99.91
Gas				
Low	85.0	66.10	68.17	71.84
Average	86.0	70.98	70.71	72.54
High	87.0	75.86	73.25	73.25
Nuclear				
Low	90.0	76.94	59.20	49.33
Average	90.0	95.42	86.36	75.22
High	90.0	113.90	113.52	101.12
Biomass				
Low	68.0	112.50	100.07	87.63
Average	75.5	112.50	101.80	93.00
High	83.0	113.90	103.54	98.36
Wind				
Low	15.5	148.78	96.10	87.50
Average	26.9	218.23	182.82	169.45
High	34.4	287.67	269.54	251.40

http://eetd.lbl.gov/EA/EMP (accessed December 2011); 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 2011).

We use the EIA's reference case scenario for all technologies. Since capital costs represent the largest 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 AEPS. With coal, for example, we multiplied the avoided amount generation of electricity from coal (3.05 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 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 AEPS, because this figure represents the amount of conventional electricity generation capacity that presumably will not be needed under the AEPS. The difference between the cost of the new renewable sources and the costs of the conventional electricity generation Pennsylvania represents the net cost of the AEPS. Tables 8, 9 and 10 on the following pages display the results of our Average, Low and High Cost calculations for the 15 percent AEPS respectively.

Table 8: Average Cost Case of 15 percent AEPS Mandate from 2013 to 2021

Year	Gross Cost (2010 $000s)	Less Conventional (2010 $000s)	Total (2010 $000s)
2013	1,519,780	83,432	1,436,348
2014	1,465,954	98,863	1,367,092
2015	1,450,893	110,792	1,340,101
2016	1,779,093	124,520	1,654,573
2017	1,954,197	140,322	1,813,875
2018	2,138,996	157,103	1,981,893
2019	2,180,679	167,256	2,013,423
2020	2,387,675	186,196	2,201,479
2021	2,752,564	204,878	2,547,686
Total	**17,629,831**	**1,273,361**	**16,356,470**

Table 9: Low Cost Case of 15 percent AEPS Mandate from 2013 to 2021

Year	Gross Cost (2010 $000s)	Less Conventional (2010 $000s)	Total (2010 $000s)
2013	1,365,121	131,351	1,233,770
2014	1,282,319	155,144	1,127,175
2015	1,244,841	173,616	1,071,226
2016	1,547,648	195,183	1,352,465
2017	1,693,340	219,891	1,473,450
2018	1,846,846	246,176	1,600,670
2019	1,603,327	274,615	1,328,712
2020	1,744,974	305,079	1,439,895
2021	2,046,172	336,075	1,710,097
Total	**14,374,589**	**2,037,128**	**12,337,460**

Table 10: High Cost Case of a 15 percent AEPS Mandate from 2013 to 2021

Year	Gross Cost (2010 $000s)	Less Conventional (2010 $000s)	Total (2010 $000s)
2013	1,774,737	60,406	1,714,332
2014	1,768,670	72,219	1,696,451
2015	1,790,533	81,072	1,709,460

2016	2,160,545	91,887	2,068,658
2017	2,384,124	103,619	2,280,505
2018	2,620,527	115,403	2,505,123
2019	2,686,743	109,687	2,577,056
2020	2,950,993	120,664	2,830,329
2021	3,371,710	132,434	3,239,276
Total	**21,508,581**	**887,390**	**20,621,191**

We converted the aggregate cost of the AEPS into a cost per-kWh by dividing the cost by the estimated total number of kWh sold for that year. For example, for 2021 under the average cost scenario above, we divided $1.4 billion into 111.34 billion kWhs for a cost of 1.27 cents per kWh.

Ratepayer Effects

To calculate the effect of the AEPS on electricity ratepayers we used EIA data on the average monthly electricity consumption by type of customer: Residential, commercial and industrial.[32] The monthly figures were multiplied by 12 to compute an annual figure. We inflated the 2010 figures for each year using the average annual increase in electricity sales over the entire period.[33]

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 11,721 kWhs of electricity in 2021 and we expect the average cost scenario to raise electricity costs by 1.45 cents per kWh in the same year. Therefore we expect residential ratepayers to pay an additional $170 in 2021.

[32] U.S. Department of Energy, Energy Information Administration, "Average electricity consumption per residence in MT in 2008," (January 2010) http://www.eia.gov/electricity/sales_revenue_price/index.cfm.
[33] U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2010*, "Table 8: Electricity Supply, Disposition, Prices, and Emissions," http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html.

Modeling the AEPS 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 AEPS policy.

Because the AEPS requires Pennsylvania 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 AEPS. 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 AEPS. Standard economic theory shows that a price increase of a good or service leads to a decrease in overall consumption, and consequently a decrease in the production of that good or service. As producer output falls, the decrease in production results in a lower demand for capital and labor.

BHI utilized its STAMP (State Tax Analysis Modeling Program) model to identify the economic effects and understand how they operate through a state's economy. STAMP is a five-year dynamic CGE (computable general equilibrium) model that has been programmed to simulate changes in taxes, costs (general and sector-specific) and other economic inputs. As such, it provides a mathematical description of the economic relationships among producers, households, governments and the rest of the world. It is general in the sense that it takes all the important markets, such as the capital and labor markets, and flows into account. It is an equilibrium model because it assumes that demand equals supply in every market (goods and services, labor and capital). This equilibrium is achieved by allowing prices to adjust within the model. It is computable because it can be used to generate numeric solutions to concrete policy and tax changes.[34]

In order to estimate the economic effects of a national AEPS 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

[34] 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).

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 AEPS 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.[35] 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 2021 for our average cost case we divided our average price of 12.15 cents per kWh by our estimated price increase of 1.45 cents per kWh for a price increase of 11.9 percent.

Table 11: Elasticities for the Economic Variables

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

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' economy. We then averaged the percent changes together to determine what the average effect of the three utility increases. Table 11 displays these elasticities, which were then applied to the calculated percent change in electricity costs for the state of Pennsylvania discussed above.

We applied the elasticities to percentage increase in electricity price and then applied the result to Pennsylvania economic variables to determine the effect of the AEPS. These variables were

[35] U.S. Department of Energy, Energy Information Administration, Pennsylvania Electricity Profile 2010, Table 8: Retail Sales, Revenue, and Average Retail Price by Sector, 1990 through 2008, http://www.eia.gov/electricity/state/.

gathered from the Bureau of Economic Analysis Regional and National Economic Accounts as well as the Bureau of Labor Statistics Current Employment Statistics.[36]

[36] 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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