July 2016

NORTH CAROLINA'S RENEWABLE PORTFOLIO STANDARD: EXAMINING THE ECONOMIC EFFECTS

Timothy J. Considine, Ph.D.
Principal Investigator
Natural Resource Economics, Inc.

EVALUATING THE COSTS AND BENEFITS OF RENEWABLE ENERGY PORTFOLIO STANDARDS

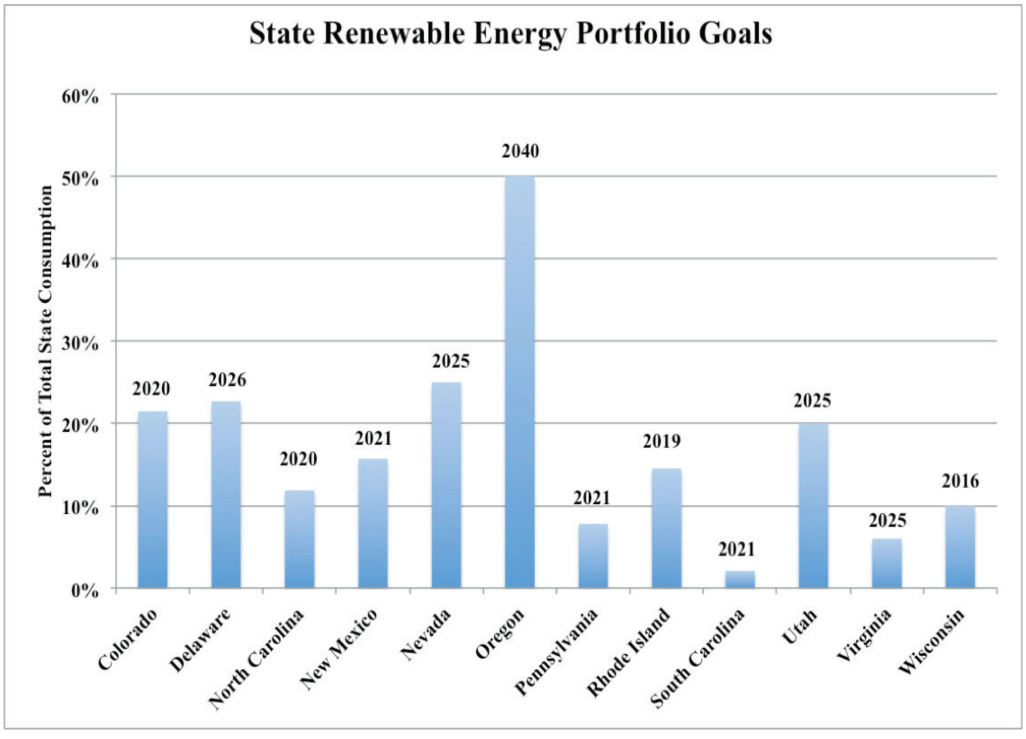
Executive Summary

Renewable Portfolio Standards (RPS), now existing in 29 states and the District of Columbia, require utilities to provide a certain percentage of electricity consumption from wind, solar, and other forms of renewable energy. Federal policies, such as the wind production tax credit and the solar investment tax credit, also promote the production of wind and solar power. Given the widespread use of rate of return regulation based upon average cost pricing, the costs of these policies are less than transparent. Moreover, to the extent that these policies drive up electricity prices, output and employment could be adversely affected. The objective of this study is to understand and estimate these costs and economic impacts.

Central to this effort is the estimation of the opportunity costs of higher cost, intermittent renewable power in terms of the foregone electricity from lower cost, deployable fossil fuel fired electricity. These opportunity costs vary considerably by state based upon the cost of existing capacity and availability of wind and solar resources. Accordingly, this study estimates these costs for the twelve states identified in Figure ES1. The timing and stringency of the RPS goals varies considerably by state. Moreover, there is wide variation in the size and composition of electricity generation for this sample of states.[1]

To estimate the costs and benefits of RPS, this study develops models of electricity supply and demand

Figure ES1: RPS Goals by State



for each state. These models are projected using forecasts for coal and natural gas prices out to 2040 from the U.S. Energy Information Administration. The baseline forecast assumes existing electricity production capacity remains in place with new generation requirements met by natural gas integrated combined cycle (NGCC) plants. The RPS scenario imposes the goals identified in Figure ES1. Average electricity generation costs, power consumption, and retail rates under the baseline and RPS scenarios are then compared.

The costs of RPS policies depend upon the opportunity costs of electricity generation from wind and solar. For states with a fleet of low cost electricity generation capacity, imposition of RPS could raise electricity costs significantly because higher cost wind and solar generation displace low cost sources of power. While this displacement reduces expenditures on fossil fuels, coal and natural gas plants are cycled to accommodate the intermittent generation of renewable generators, which reduces their thermal efficiency and raises generation costs. On the other hand, building more renewable energy plants to meet RPS goals reduces the need to build new NGCC plants. Finally, investments in RPS capacity earn federal tax subsidies. Wind power receives a production tax credit of $23 per megawatt hour (Mwh) while solar plants receive a 30% investment tax credit. Hence, RPS policies contribute to lower federal tax revenues.

These costs are summarized in Figure ES1 for the entire twelve states. For example, in 2016, the RPS goals involve $5.4 billion in additional expenditures to build and operate the required RPS facilities, $271 million in cycling costs, and $1.8 billion of tax subsidies. These costs are partially offset by $1.478 billion in fossil fuel cost savings and $261 million in avoided new NGCC generation costs. Hence, the total net cost of RPS policies is $5.762 billion in 2016. The total net costs of RPS policies reach $8.7 billion in 2025 and increase to $8.9 billion in 2040 after RPS goals are met and the unit costs of solar and wind decline due to technological improvements.

These higher costs are passed on to customers in the form of higher retail electricity prices, summarized in Table ES2. States with modest RPS goals, such as South Carolina, experience moderate rate increases. Similarly, states meeting their RPS goals with wind, such as Colorado, face rate increases of roughly 6%. On the other hand, states meeting rather ambitious RPS goals with relatively higher cost solar power, such as Oregon, North Carolina, Nevada, Utah, and Virginia incur much steeper electricity rate increases.

Electricity rate increases peak as RPS goals are reached in the early 2020s for most states. Thereafter, electricity rate increases begin to taper off as the costs of wind and solar decline due to technological improvements. Despite these expected reductions in

Table ES1: Costs of RPS for Entire 12 State Sample

	MILLIONS OF 2013 DOLLARS					
	2016	2020	2025	2030	2035	2040
Renewable Energy Costs	5,400.0	7,815.2	8,881.6	9,283.8	9,693.2	10,119.0
Cycling Costs	271.1	316.0	339.6	371.9	409.2	452.6
Tax Subsidies	1,830.1	2,672.2	3,098.0	3,287.2	3,485.7	3,698.8
Fossil Fuel Costs	-1,478.3	-2,319.5	-2,966.3	-3,493.3	-4,071.0	-4,687.0
New Fossil Fuel Costs	-260.7	-462.0	-597.5	-619.6	-642.1	-652.3
Total Net Costs	5,762.2	8,022.0	8,755.4	8,829.9	8,875.0	8,931.1

the cost of wind and solar technology, RPS polices increase prices for electricity.

Many economic studies in the peer-reviewed literature demonstrate that higher energy prices reduce economic growth and employment. Energy is an essential factor of production and consumption activities. Given limited substitution possibilities, higher electricity prices raise business costs and consumer energy bills, which reduces spending on other goods and services. Investments in renewable energy, however, constitute an economic stimulus.

A comparison of these economic impacts is summarized in Table ES3 for the entire twelve states. For example, in 2025 higher electricity prices associated with RPS policies reduce value added or net economic output by $23.1 billion. Investments required for new renewable energy plants increase value added by $668 million. With a small offset from reductions in required NGCC plants to meet load growth, the net reduction in value added is nearly $22.5 billion in 2025. Similarly, gross employment losses are over 160 thousand in 2025 but over 9 thousand jobs are created building and operating new solar and wind capacity to meet RPS goals. But again the net change involves over 150 thousand jobs lost in 2025. Overall, this study finds that the stimulus from building and operating renewable energy facilities are offset by the negative impacts that higher electricity rates have on employment and value added. The estimated losses in value added for each of the twelve states are summarized in Table ES4. The largest losses occur in North Carolina with value added reductions between $3.9 billion in 2016 to more than $6.6 billion in 2025. Losses in annual value added exceed $1 billion in seven other states.

The employment impacts of RPS policies are summarized in Table ES5. The jobs lost by state mirror the losses in value added. Again, the magnitudes differ by state depending upon the stringency of the RPS goals, the size of the state, and the technologies available for each state to meet the RPS goals. Solar energy is the main way to attain RPS goals for eastern states due to limited wind resources.

Table ES2: Impact of RPS Policies on Retail Electricity Prices

	ELECTRICITY PRICE CHANGES IN PERCENT					
	2016	2020	2025	2030	2035	2040
Colorado	6.12	8.23	7.69	7.32	6.69	5.93
Delaware	11.02	14.50	14.99	12.50	10.14	8.20
North Carolina	10.04	16.06	14.12	12.55	11.03	9.79
New Mexico	6.18	6.77	5.95	5.30	4.54	3.92
Nevada	14.77	15.60	15.14	13.28	11.21	9.12
Oregon	9.41	10.00	11.09	14.13	16.42	18.13
Pennsylvania	2.14	2.56	2.54	2.40	2.25	2.08
Rhode Island	13.61	18.16	16.62	15.55	14.46	13.17
South Carolina	0.39	1.52	2.08	1.97	1.85	1.75
Utah	5.13	9.07	12.78	11.78	10.67	9.47
Virginia	5.45	7.75	9.85	8.76	7.74	6.93
Wisconsin	4.34	4.29	4.01	3.70	3.39	3.08

Table ES3: RPS Impacts on Value Added and Employment for All States

	MILLIONS OF 2013 DOLLARS					
Value Added	**2016**	**2020**	**2025**	**2030**	**2035**	**2040**
Electric prices	-16,779	-22,799	-23,140	-21,555	-19,786	-18,100
RPS Invest.	2,069	1,290	668	432	439	456
NGCC Invest.	-146	-34	-22	-2	1	2
Net Change	-14,856	-21,543	-22,495	-21,124	-19,346	-17,642
Employment	NUMBER OF JOBS					
Electric prices	-118,606	-159,094	-161,595	-151,605	-140,199	-129,223
RPS Invest.	29,826	18,332	9,073	5,796	5,870	6,092
NGCC Invest.	-1,246	-305	-206	-21	10	15
Net Change	-90,026	-141,066	-152,727	-145,830	-134,318	-123,116

Table ES4: RPS Impacts on Value Added by State

	CHANGE IN VALUE ADDED IN MILLIONS OF 2013 DOLLARS					
	2016	**2020**	**2025**	**2030**	**2035**	**2040**
Colorado	-1,442	-1,996	-1,992	-1,895	-1,730	-1,530
Delaware	-603	-812	-839	-715	-578	-466
North Carolina	-3,899	-7,145	-6,664	-5,918	-5,196	-4,606
New Mexico	-239	-444	-390	-348	-298	-251
Nevada	-1,711	-1,792	-1,715	-1,534	-1,287	-1,038
Oregon	-1,451	-1,571	-1,636	-2,022	-2,374	-2,636
Pennsylvania	-1,226	-1,503	-1,640	-1,545	-1,449	-1,337
Rhode Island	-629	-890	-813	-760	-707	-643
South Carolina	-63	-198	-349	-318	-298	-283
Utah	-662	-1,420	-2,025	-1,964	-1,777	-1,575
Virginia	-1,865	-2,655	-3,390	-3,149	-2,778	-2,486
Wisconsin	-1,065	-1,116	-1,041	-958	-874	-791
Total	-14,856	-21,543	-22,495	-21,124	-19,346	-17,642

The economic impacts are summarized in Figure ES2 using the present discounted value of lost value added and average annual job losses from 2016 to 2040. The largest losses occur in North Carolina with a cumulative loss in value added of over $106 billion and annual average job losses of more than 37 thousand. The next largest losses occur in Virginia with over $50 billion in lost value added and more than 20 thousand lost jobs per year. Five other states – Colorado, Nevada, Oregon, Pennsylvania, and Utah – incur losses exceeding $25 billion in value added and 9 thousand jobs per year from 2016 to 2040 associated with the economic burdens associated with RPS policies.

RPS policies, however, generate benefits by reducing carbon dioxide emissions. These savings, however, come at a relatively high price with the avoided cost of carbon of between $234 and $38 per ton in 2016 and between $136 and $30 per ton in 2040. An emissions weighted average of CO2 abatement costs across all states is $78 in 2016 and $62 dollars per ton in 2040.

Table ES5: Impact of RPS Policies on Employment by State

	CHANGE IN NUMBER OF JOBS					
State	2016	2020	2025	2030	2035	2040
Colorado	-8,060	-11,619	-12,445	-11,823	-10,779	-9,516
Delaware	-2,705	-3,845	-3,970	-3,536	-2,846	-2,272
North Carolina	-17,821	-43,277	-44,093	-39,107	-34,289	-30,345
New Mexico	-743	-3,483	-3,060	-2,724	-2,333	-1,921
Nevada	-11,827	-12,540	-11,868	-10,813	-9,037	-7,237
Oregon	-12,309	-13,459	-13,547	-16,428	-19,422	-21,637
Pennsylvania	-7,781	-9,712	-11,396	-10,726	-10,046	-9,255
Rhode Island	-4,003	-6,023	-5,496	-5,137	-4,771	-4,339
South Carolina	-561	-1,331	-3,084	-2,794	-2,617	-2,480
Utah	-1,912	-7,137	-10,517	-11,153	-10,077	-8,916
Virginia	-13,182	-18,779	-24,060	-23,144	-20,399	-18,241
Wisconsin	-9,121	-9,862	-9,193	-8,447	-7,701	-6,957
Total	-90,026	-141,066	-152,727	-145,830	-134,318	-123,116

Figure ES2: Cumulative Economic Impacts of RPS

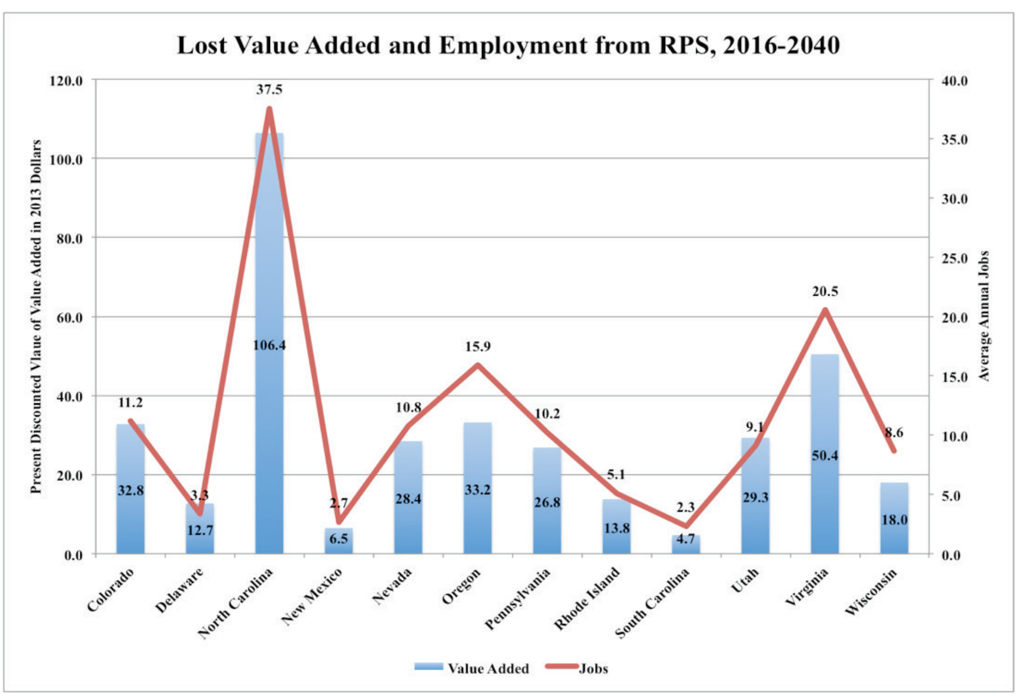


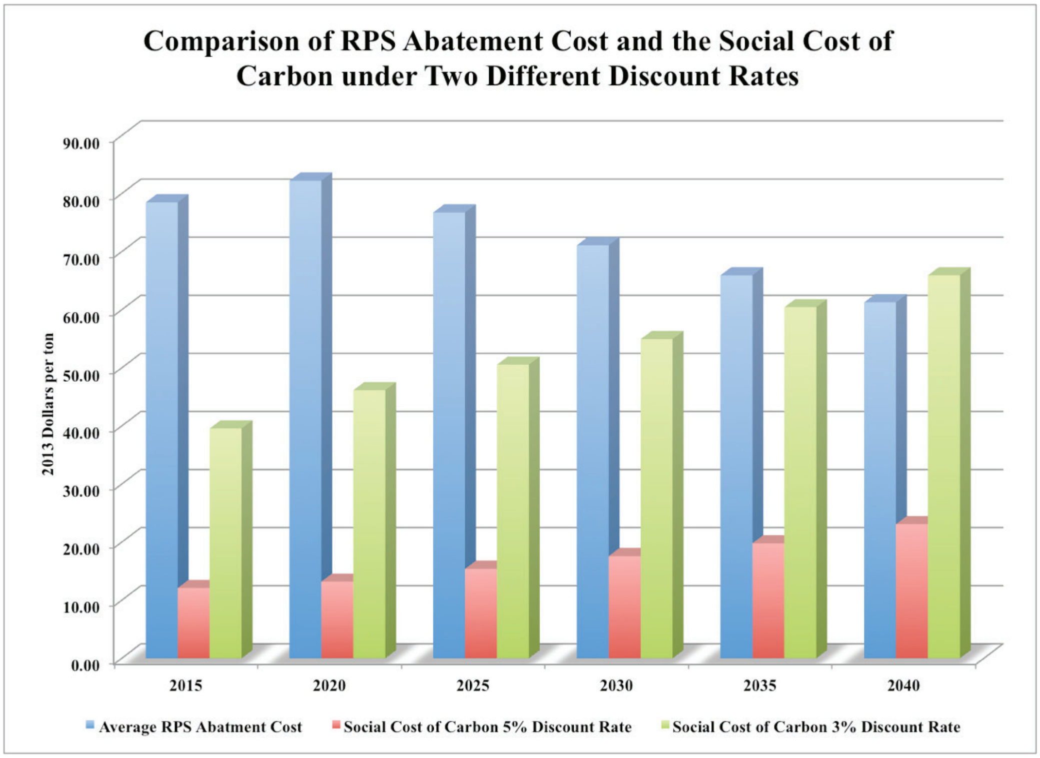
Table ES6: Costs of CO2 Reductions using RPS

	2013 DOLLARS PER TON					
State	2016	2020	2025	2030	2035	2040
Colorado	37.92	41.89	40.22	39.79	38.56	36.78
Delaware	105.74	88.83	77.70	68.22	60.16	53.31
North Carolina	199.03	183.27	162.12	147.65	134.22	122.56
New Mexico	45.92	39.80	37.09	35.02	32.46	30.59
Nevada	76.82	56.83	51.17	46.68	42.64	38.66
Oregon	45.89	49.06	45.93	47.68	47.40	46.51
Pennsylvania	44.05	44.21	42.37	41.43	40.50	39.41
Rhode Island	205.42	172.39	156.73	148.99	141.55	133.72
South Carolina	103.38	156.21	133.88	127.07	120.60	115.27
Utah	97.22	85.42	82.54	76.74	71.33	65.94
Virginia	234.91	203.97	181.92	161.71	147.34	136.03
Wisconsin	54.22	51.15	49.46	47.67	45.88	44.06

The social cost of carbon estimated by the US Environmental Protection Agency is well below these average avoided emissions costs, suggesting that Renewable Portfolio Standards are a relatively expensive strategy to cut greenhouse gas emissions (see Figure ES3). In summary, this study finds that the economic impacts of Renewable Portfolio Standards vary significantly across states depending upon the goals and the availability of solar and wind resources. Across all states, however, RPS policies increase electricity prices.

RPS investments stimulate economic activity. The negative economic impacts associated with higher electricity prices, however, offset the economic stimulus from these RPS investments. In many cases, especially for states that must utilize solar energy technology to meet RPS goals, the costs per ton of carbon is much higher than the social cost of carbon estimated by the US federal government. Avoided carbon costs are lower for wind power but still involve net losses in value added and employment. These findings suggest that Renewable Portfolio Standards for the twelve states examined in this study are a costly and inefficient means to reduce greenhouse gas emissions and they reduce economic growth and employment.

Figure ES3: RPS Abatement Costs and the Social Cost of Carbon



North Carolina Results

North Carolina has a sizeable electricity sector, generating more than 125 million MWh with 37 percent coming from coal, 32 percent from nuclear, and 22 percent from natural gas (see Table 1). Five percent of total generation comes from hydroelectric facilities and 1.7 percent from wood fired power plants. Solar power accounts for 0.3 percent of total generation in 2013 (see Table 1). The following two sub-sections summarize the impacts of existing and future RPS goals on the electricity market and state value added and employment in North Carolina.

Table 1: Capacity, Generation, and Utilization Rates for North Carolina 2013

ENERGY SOURCE	CAPACITY MW	GENERATION MWH	CAPACITY UTILIZATION %
Coal	13,021	47,072,210	0.4127
Geothermal	0	0	0.0000
Hydroelectric	1,890	6,900,533	0.4167
Natural gas	12,713	27,982,509	0.2513
Nuclear	5,395	40,241,737	0.8515
Other	50	566,884	1.2840
Other biomass	64	410,294	0.7284
Other gas	0	0	0.0000
Petroleum	504	217,571	0.0493
Pumped storage	95	0	0.0000
Solar	336	344,663	0.1170
Wind	0	0	0.0000
Wood	571	2,199,893	0.4398
Total	**34,641**	**125,936,293**	**0.4150**

Source: US Energy Information Administration

Impacts on Electricity Sector

The RPS goal for North Carolina is 11.9 percent of total consumption by 2020. The impacts on electricity markets from these goals are presented in Table 2. The RPS goals significantly reduce the need for additional new NGCC as these goals are met from 2016 to 2020. For instance, in the base case without additional RPS capacity, new NGCC capacity required to balance the market is 364.7 megawatts (MW) in the base case and with RPS incremental NGCC capacity declines to 202 MW in 2016. After 2030, NGCC capacity additions are slightly higher than the base case NGCC capacity additions because higher levels of renewables require more gas capacity serving as backup.

Slightly over 88 percent of new RPS capacity for North Carolina is supplied by solar power with the remainder met by new wind generating plants. New RPS wind and solar capacity to meet the RPS goals are 243.3 and 2,407 MW respectively in 2016. New wind and solar capacity requirements are 17.2 and 170.9 MW respectively in 2025. The electricity generation from these new facilities rises from 10.1 million MWh in 2016 to 22 million MWh in 2040 (see Table 2).

The increase in average electricity costs from RPS policies are 25 percent in 2016, rising to 42 percent in 2020, over 36 percent in 2025, and almost 24 percent in 2040 (see Table 2). The associated increases in retail electricity rates are from 9 to 15 percent. These rate increases are significant due to the reliance on relatively high cost solar power to meet RPS goals, which reflects relatively low capacity utilization rates for solar in North Carolina. These sharp increases in retail electricity rates reduce electricity consumption compared to the base case without renewable portfolio standards.

The decomposition of RPS costs on the North Carolina electricity sector appear in Table 3. Net annual RPS legacy costs are $51.6 million in 2016 and remain over $38 million in 2040. Cycling costs due to the inefficient operation of the electricity gird to accommodate intermittent renewable energy sources are roughly equal to the fossil fuel cost savings.

The costs arising from new renewable capacity associated to meet North Carolina's RPS goals are also summarized in Table 3. The net costs associated with new RPS capacity are $1.17 billion in 2016, $1.9 billion in 2020, $1.8 billion in 2025 and remain $1.4 billion out to 2040. RPS tax subsidies associated with North Carolina's renewable electricity generators are significant, increasing from $546 million in 2016 to over $937 million in 2020. Total RPS costs, which include legacy and new RPS costs and tax subsidies, are over $1.7 billion in 2016 and rise to over $2.9 billion in 2020.

Table 2: Impacts of RPS on North Carolina Electricity Market

MEGAWATTS						
	2016	2020	2025	2030	2035	2040
New NGCC Capacity						
Without RPS	364.7	258.5	226.2	231.9	239.8	256.2
With RPS	202.0	229.5	224.1	233.9	243.3	258.9
New RPS Capacity						
Wind	242.3	140.1	17.2	17.9	18.7	19.9
Solar	2407.7	1391.9	170.9	178.4	185.6	197.5
MILLION MEGAWATT HOURS						
New NGCC Generation						
Without RPS	9.1	17.5	26.2	34.6	43.5	52.8
With RPS	7.0	14.0	22.3	30.8	39.8	49.2
Legacy RPS Generation	0.3	0.3	0.3	0.3	0.3	0.3
New RPS Generation	10.1	17.8	18.8	19.8	20.9	22.0
PERCENTAGE CHANGES FROM BASE CASE						
Average Costs	25.01	42.15	36.26	31.85	27.55	24.30
Electricity Consumption	-0.39	-1.03	-1.18	-1.10	-0.99	-0.88
Average Rates	9.64	15.67	13.79	12.26	10.78	9.57
Average Rates + Legacy Costs	10.04	16.06	14.12	12.55	11.03	9.79

Table 3: Costs of North Carolina RPS

MILLIONS OF 2013 DOLLARS						
	2016	2020	2025	2030	2035	2040
RPS Legacy Costs						
Direct	53.1	49.9	46.3	42.9	39.8	36.9
Cycling Costs	8.4	9.8	10.3	10.6	11.0	11.3
less Fuel Costs	9.9	8.8	9.4	9.6	10.0	10.2
Net RPS Legacy Costs	51.6	50.9	47.3	43.9	40.8	38.0
New RPS Costs						
Direct	1,532.9	2,557.6	2,518.7	2,477.5	2,437.1	2,397.5
Cycling Costs	8.9	10.2	10.9	11.1	11.6	11.8
less Fuel Costs	286.7	534.5	632.4	697.1	768.8	829.9
less NGCC Costs	78.7	117.2	135.1	136.7	136.3	131.2
Net New RPS Costs	1,176.5	1,916.2	1,762.0	1,654.8	1,543.5	1,448.3
RPS Tax Subsidies	546.7	937.9	925.6	912.0	898.3	884.7
Total RPS Cost	**1,774.7**	**2,904.9**	**2,734.9**	**2,610.7**	**2,482.7**	**2,371.0**
MILLION TONS						
CO2 Reductions	8.92	15.85	16.87	17.68	18.50	19.35
2013 DOLLARS PER TON OF CO2 REDUCED						
Direct RPS Costs	137.72	124.10	107.25	96.08	85.65	76.83
Subsidy Costs	61.31	59.17	54.87	51.58	48.56	45.73
Total Costs	**199.03**	**183.27**	**162.12**	**147.65**	**134.22**	**122.56**

The RPS policies reduce carbon dioxide emissions by 8.92 million tons in 2016 to over 19 million tons per year by 2040 (see Table 3). The direct costs per ton of avoided emissions are $137.72 per ton in 2016 and decline to $76.83 per ton in 2040 as wind and solar costs decline over time. Tax subsidies, however, are over $61 per ton in 2016 and remain over $45 per ton in 2040. The total costs of avoided carbon emissions, therefore, are $199 per ton in 2016 and $122 per ton in 2040.

These RPS carbon abatement costs are well beyond the EPA social cost of carbon, indicating that RPS policies in North Carolina are a very inefficient greenhouse gas emission strategy. So even from a global cost-benefit perspective, adopting RPS policies in North Carolina would involve a net loss in producer and consumer surplus or net social welfare. From a North Carolina perspective, the wide gap between the estimated RPS carbon abatement costs and the social benefit from reducing greenhouse gas emissions estimated by the avoided social costs of carbon is compounded by the significant losses in economic output and employment associated with the significant increase in electricity rates caused by renewable energy portfolio standards. These impacts are now presented and discussed.

Economic Impacts

By raising retail prices for electricity, RPS goals raise consumer electricity bills and the costs of providing goods and services in the North Carolina economy. These impacts of higher electricity prices are summarized by sector from 2016 to 2040 in Table 4. Annual losses in North Carolina value added range from $4.78 billion in 2016 to $7.6 billion in 2020, and over $4.6 billion in 2040. Employment levels are 30,000 to 50,000 below employment in the base case without renewable energy portfolio standards (see Table 5). Other manufacturing and services are particularly hard hit

Table 4: Impacts of RPS on North Carolina Value Added by Sector

MILLIONS OF 2013 DOLLARS						
	2016	**2020**	**2025**	**2030**	**2035**	**2040**
Metals	-105.45	-168.62	-148.27	-131.80	-115.85	-102.83
Paper	-140.61	-224.83	-197.69	-175.73	-154.46	-137.10
Wood	-71.31	-114.02	-100.26	-89.12	-78.33	-69.53
Other Man	-1,326.72	-2,121.43	-1,865.37	-1,658.14	-1,457.47	-1,293.64
Textiles	-88.38	-141.32	-124.26	-110.46	-97.09	-86.18
Minerals	-53.23	-85.11	-74.84	-66.53	-58.48	-51.90
Const.	-541.34	-865.60	-761.11	-676.56	-594.68	-527.84
Trans.	-203.88	-326.00	-286.65	-254.81	-223.97	-198.80
Services	-2,693.62	-4,307.10	-3,787.21	-3,366.48	-2,959.07	-2,626.46
Utilities	444.92	711.43	625.55	556.06	488.76	433.83
Total	**-4,780.62**	**-7,644.22**	**-6,721.53**	**-5,974.81**	**-5,251.73**	**-4,661.42**

Table 5: Impacts of RPS on North Carolina Employment by Sector

NUMBER OF JOBS						
	2016	**2020**	**2025**	**2030**	**2035**	**2040**
Metals	-266	-426	-374	-333	-292	-260
Paper	-863	-1,379	-1,213	-1,078	-948	-841
Wood	-893	-1,428	-1,255	-1,116	-981	-871
Other Man	-3,920	-6,268	-5,511	-4,899	-4,306	-3,822
Textiles	-2,406	-3,848	-3,383	-3,007	-2,644	-2,346
Minerals	-144	-230	-202	-179	-158	-140
Const.	-4,108	-6,568	-5,775	-5,134	-4,513	-4,005
Trans.	-3,025	-4,837	-4,253	-3,781	-3,323	-2,950
Services	-17,134	-27,397	-24,090	-21,414	-18,822	-16,707
Utilities	753	1,204	1,059	941	827	734
Total	**-32,006**	**-51,178**	**-45,000**	**-40,001**	**-35,160**	**-31,208**

These losses from higher electricity prices are partially offset by output and employment gains from building and operating electricity capacity needed to meet RPS goals. On the other hand, RPS investment also precludes new NGCC investment. These different impacts of RPS on North Carolina value added and employment are summarized in Table 6. For example, in 2016 RPS investments contributed $927 million in value added and 14,588 jobs. Avoided NGCC investments reduce value added $46.21 million in 2020.

The stimulus from RPS investment, however, is not large enough to offset the negative impacts of higher electricity prices. On balance, therefore, net annual losses in value added from North Carolina's RPS goals are $3.9 billion in 2016, $7.145 billion in 2020 and remain well above $4 billion out to the end of the forecast horizon in 2040. Employment levels are 17,821 lower in 2016, 43,277 lower in 2020, and 44,093 lower in 2025.

Table 6: Net Impacts of RPS on North Carolina Value Added and Employment

MILLIONS OF 2013 DOLLARS						
	2016	2020	2025	2030	2035	2040
RPS Invest.	4,523.89	2,476.02	284.05	277.03	269.46	268.17
Value Added						
Electric prices	-4,780.62	-7,644.22	-6,721.53	-5,974.81	-5,251.73	-4,661.42
RPS Invest.	927.39	507.36	58.17	56.70	55.12	54.82
NGCC Invest.	-46.21	-8.24	-0.59	0.58	1.01	0.76
Net Change	-3,899.44	-7,145.10	-6,663.95	-5,917.54	-5,195.61	-4,605.84
Employment	NUMBER OF JOBS					
Electric prices	-32,006	-51,178	-45,000	-40,001	-35,160	-31,208
RPS Invest.	14,588	7,973	913	889	863	857
NGCC Invest.	-403	-72	-5	5	9	7
Net Change	-17,821	-43,277	-44,093	-39,107	-34,289	-30,345

In summary, the costs of avoiding carbon dioxide emissions using renewable portfolio standards in North Carolina are substantially higher than EPA estimates of the social cost of carbon. From a global perspective, therefore, renewable energy portfolio standards in North Carolina are an inefficient means to address global climate change. Other strategies employing alternative resources and technologies to reduce greenhouse gas emissions could be far more cost effective.

Moreover, the RPS goals impose additional costs on households and businesses in North Carolina in the form of billions of dollars in lost value added and tens of thousands of jobs lost. Hence, RPS policies for North Carolina involve a double penalty with marginal abatement costs far above the expected benefits from reducing greenhouse gas emission and burdens on the local economy that reduce growth and employment.

I. Methodology

Renewable Portfolio Standards are generally met with wind and solar electric generating technologies. Relatively small amounts of biomass and other renewable sources of generation are also used to meet these standards. Given this fact and the limited information available on these alternatives to wind and solar this study assumes that RPS goals are met by building wind and solar generation capacity.

Adding these facilities to a generation fleet incurs opportunity costs, which vary depending upon the cost, efficiency, and composition of the existing fleet of generation capacity. Likewise, the benefits in terms of avoided emissions will also vary with the characteristics of the generation fleet. Hence, the opportunity costs of RPS policies could vary considerably by state. For example, if a state has a high cost of electric power generation, adding wind and solar would involve relatively lower costs than those incurred for a system with very low costs. These costs are also affected by coal, oil, and natural gas prices among other factors. If natural gas prices rise, for instance, the increase in average generation costs from adopting RPS policies would be relatively lower than under low natural gas prices.

Another important adjustment affecting the opportunity costs of RPS policies is how the demand for electricity adjusts to higher electricity rates that would be required to recover the additional costs of building and operating renewable energy plants. This price induced energy conservation would reduce the costs of RPS policies.

To estimate these electricity supply and demand adjustments in response to RPS policies, this study develops a simplified version of the models developed by Considine and Manderson (2014, 2015) in which electricity demand models are integrated with engineering-economic models of electric power generation. Electricity demand is projected based upon assumptions for the growth of gross state product and upon retail electricity prices that are determined based upon average generation costs determined from the engineering-economic model of electricity generation.

These costs are calculated based upon observed levels of installed generation capacity, utilization rates, and unit costs of generation that include operating and capital cost recovery. In other words, available generation from existing natural gas, coal, nuclear, hydro, and renewable capacity are estimated by multiplying the respective capacities by their utilization rates. The displacement of fossil fuel generation and associated efficiency losses due to sub-optimal cycling of these plants to balance system load with rising levels of intermittent renewable energy generation are estimated using the Avoided Emissions and Generation Tool developed by the U.S. Environmental Protection Agency (2015). For this study, these models are run and estimated for each of the twelve states.

These electricity supply and demand models for each state are simulated from 2016 to 2040 under two scenarios. The first scenario is the base case defined as the existing generation fleet without RPS policies in place. For existing wind and solar capacity, which are assumed to reflect current RPS, costs and benefits are computed separately and are designated as RPS legacy costs. Electricity supply and demand are balanced by new investment and generation from natural gas integrated combined cycle (NGCC) plants. The second scenario assumes the RPS goals are phased in over the forecast horizon, specifying an amount of wind and solar generation equal to the RPS share multiplied by projected electricity consumption. In this case, the required amount of new NGCC capacity would be reduced due to the rising share of renewable energy in the generation portfolio. The impacts of RPS policies on retail electricity prices are determined by comparing retail electricity prices in these two scenarios.

These retail electricity price changes, and the net changes in new power plant investments will affect local economic activity. Value added and employment multipliers reported by recent economic studies will be used to estimate the state level economic impacts of RPS policies. The Jobs and Economic Development Impact (JEDI) modeling tool developed by the National Renewable Energy Laboratory (2015) is used to estimate the impacts of power plant investments on value added and employment. The net effects on employment and value added are then estimated.

Benefits are the avoided air emissions, which are estimated by taking the difference between emissions in the base case and the RPS scenario including the emissions saved from existing wind and solar capacity. The total cost of RPS policies defined above divided by these emission savings provide an estimate of the unit cost of greenhouse gas reductions from RPS policies.

The following five sub-sections describe the results obtained from the econometric estimation of the electricity demand models, the specification of the electricity generation cost models, average cost calculations under RPS policies, the decomposition of RPS opportunity costs, and the parameters used for the economic impact analysis.

Electricity Demand

The demand for electricity is a simple partial adjustment model in log-linear form, in which total consumption of electricity in state i, , is a function of the real price for electricity, P_{it}, gross state product or total value added, Y_{it}, and lagged consumption, Q_{it-1} :

$$\ln Q_{it} = \alpha_i + \beta_i \ln P_{it} + \gamma_i \ln Y_{it} + \lambda_i Q_{it-1} . \qquad (1)$$

where α_i, β_i, λ_i are parameters estimated with ordinary least squares. This equation is estimated for each of the twelve states. The results for alternative specifications including a first differenced version, a specification with natural gas prices, and fixed and random effects models appear in Appendix A and are not substantially different from those reported in Tables M1-M3.

The econometric estimates for equation (1) are reported below in Table M1. As expected, the coefficients on price for all twelve states are negative indicating an inverse relationship between electricity consumption and retail prices. Eight out of the twelve price coefficients are statistically different from zero at either the one or five percent level of significance. Similarly, the coefficients on gross state product are positive, which reflects the well know positive relationship between economic growth and electricity use. Eleven of the 12 estimated income coefficients are statistically significant. The summary fit statistics reported in Table M2 reflect a very good fit of the models to the observed data and the absence of autocorrelation. Eight of the twelve models have very low probabilities of unit roots in the residuals. The own price and output elasticities appear in Table M3. The short-run and long-run own price elasticities are on average -0.07 and -0.20 respectively, which are quite similar to those found in the economic literature. Output elasticities average 0.2 and 0.5 in the short and long-run respectively across the twelve states that again are very close to estimates found in many other studies. With projections of future gross state product and retail prices, equation (1) can be used to project future electricity consumption.

Generation Costs

The supply of electricity is determined by simple engineering-economic relationships and generation cost calculations. Generation is determined by multiplying installed capacity by utilization rates. Costs of electricity generation are determined on the basis of the levelized costs of generation, which include operating costs and capital cost recovery charges. Retail electricity prices equal average generation cost plus a fixed markup for transmission and distribution charges.

Table M1: Electricity Demand Model Parameter Estimates by State

STATE	ESTIMATE	CONSTANT	LOG OF REAL PRICE	LOG OF REAL GSP	LAGGED QUANTITY
Colorado	Estimate	-0.4902	-0.0379	0.1447	0.7701
	t-Statistic	-1.9138	-2.4042	3.2219	12.8862
	P-Value	[.063]	[.021]	[.003]	[.000]
Delaware	Estimate	-0.6542	-0.1395	0.2465	0.5723
	t-Statistic	-2.9194	-4.7098	4.8575	7.0174
	P-Value	[.006]	[.000]	[.000]	[.000]
North Carolina	Estimate	-0.2608	-0.0278	0.1706	0.6959
	t-Statistic	-1.0556	-1.1898	2.3595	6.1758
	P-Value	[.298]	[.241]	[.023]	[.000]
New Mexico	Estimate	0.0475	-0.0280	0.0392	0.9099
	t-Statistic	0.1156	-0.5632	0.7022	13.3443
	P-Value	[.909]	[.577]	[.487]	[.000]
Nevada	Estimate	-1.0216	-0.1686	0.2877	0.6216
	t-Statistic	-4.8414	-6.2297	6.2116	10.2848
	P-Value	[.000]	[.000]	[.000]	[.000]
Oregon	Estimate	0.5212	-0.0491	0.0849	0.7277
	t-Statistic	2.7591	-1.5102	2.2751	7.4734
	P-Value	[.009]	[.139]	[.028]	[.000]
Pennsylvania	Estimate	0.1410	-0.0814	0.2132	0.5643
	t-Statistic	1.1377	-3.9395	3.7515	5.2630
	P-Value	[.262]	[.000]	[.001]	[.000]
Rhode Island	Estimate	-0.4151	-0.1020	0.1981	0.5877
	t-Statistic	-3.1521	-6.3470	6.2642	9.4167
	P-Value	[.003]	[.000]	[.000]	[.000]
South Carolina	Estimate	-1.4600	-0.0864	0.4437	0.3557
	t-Statistic	-3.5542	-3.5018	4.5002	2.6698
	P-Value	[.001]	[.001]	[.000]	[.011]
Utah	Estimate	-0.9474	-0.0228	0.2057	0.6969
	t-Statistic	-1.8262	-1.3388	2.4048	6.2836
	P-Value	[.075]	[.188]	[.021]	[.000]
Virginia	Estimate	-0.4332	-0.0385	0.1711	0.7208
	t-Statistic	-1.4929	-1.9802	2.6287	7.8650
	P-Value	[.144]	[.055]	[.012]	[.000]
Wisconsin	Estimate	-1.1833	-0.0816	0.3342	0.5010
	t-Statistic	-3.0000	-3.1200	3.8977	4.2555
	P-Value	[.005]	[.003]	[.000]	[.000]

Table M2: Electricity Demand Model Summary Fit Statistics by State

STATE	ADJ. R-SQUARED	DURBIN H PROBABILITY VALUE	WEIGHTED SYMMETRIC UNIT ROOT PROB.
Colorado	0.998	0.029	0.010
Delaware	0.990	0.481	0.000
North Carolina	0.993	0.576	0.274
New Mexico	0.990	0.494	0.000
Nevada	0.998	0.288	0.001
Oregon	0.943	0.780	0.739
Pennsylvania	0.987	0.975	0.031
Rhode Island	0.992	0.259	0.416
South Carolina	0.995	0.931	0.021
Utah	0.997	0.738	0.008
Virginia	0.996	0.224	0.143
Wisconsin	0.994	0.308	0.004

Table M3: Short and Long-Run Price and Income Elasticities of Electricity Demand

	OWN PRICE ELASTICITY		GROSS STATE PRODUCT ELASTICITY	
State	**Short-Run**	**Long-Run**	**Short-Run**	**Long-Run**
Colorado	-0.038	-0.165	0.145	0.629
Delaware	-0.139	-0.326	0.246	0.576
North Carolina	-0.028	-0.092	0.039	0.129
New Mexico	-0.028	-0.311	0.039	0.435
Nevada	-0.169	-0.445	0.288	0.760
Oregon	-0.049	-0.180	0.085	0.312
Pennsylvania	-0.081	-0.187	0.213	0.489
Rhode Island	-0.102	-0.247	0.198	0.480
South Carolina	-0.086	-0.134	0.444	0.689
Utah	-0.023	-0.075	0.206	0.679
Virginia	-0.023	-0.082	0.206	0.737
Wisconsin	-0.082	-0.163	0.334	0.670
Average	-0.071	-0.201	0.204	0.549

Installed capacity for each state is adjusted for planned generation and capacity additions and retirements reported by the US Energy Information Administration (2016) from 2014 to 2025. Total generation from various types of capacity is defined as:

$$G_{it} = \sum_{j=cl}^{wo} G_{ijt}$$

where the index j includes 13 different type of electricity generation, including coal (cl), geothermal (gt), hydro (hy), natural gas (ng), nuclear (nu), other (ot), other biomass (ob), other gas (og), petroleum (pe), pumped storage (ps), solar (sl), wind (wn), and wood (wo). The base year of generation is 2013.

Under the base case scenario, new generation requirements are met with new natural gas combined cycle generation (nc), G_{inct}, which is determined as follows:

$$G_{inct}=Q_{it}-B_{it}-G_{it} \qquad (3)$$

where B_{it} is a balance term that includes net electricity imports and other miscellaneous adjustments, which is held fixed at base year values of 2013 over the forecast horizon. This formulation implies that electricity imports do not adjust to changes in RPS policies.

The average cost of generation is defined as follows:

$$AC_{it} = \frac{\left[\sum_{j=cl}^{wo} c_{ijt} G_{ijt} + c_{inct} G_{inct}\right]}{G_{it} + G_{inct}},$$

where C_{ijt} is the levelized cost of existing generation in state i for capacity type j in year t and C_{inct} is the levelized cost of new natural gas combined cycle generation, defined as operating costs plus capital and maintenance costs:

$$c_{inct} = HR_{nc} \times P_{ingt} + \frac{p_{nc} K_{nc}\left[\frac{r(1+r)^t}{(1+r)^t - 1} + OM_{nc}\right]}{\left[K_{nc} U_{nc} \times 365 \times 24\right]}$$

where HR_{nc} is the heat rate for new NGCC capacity in million BTU per Mwhr assumed to be 6.43, P_{ngt} is the price of natural gas paid by electric utilities in 2013 dollars per million BTU, p_{nc} is the so-called overnight capital costs of NGCC capacity equal to \$1,023 per kilowatt (KW) capacity, K_{nc} is installed capacity of 400 KW, r is the discount rate assumed to be 7.1 percent per annum, t is the capital cost recovery period of 20 years, OM_{nc} is operating and maintenance expenditures per KW of capacity, and U_{nc} is the capacity utilization rate for NGCC units, which is assumed to be 85 percent. The last two terms in the denominator of the second term in equation (5) computes the number of hours in a calendar year so that levelized costs are in terms of dollars per megawatt hours of electricity generation. The values of these cost parameters are based upon data provided by EIA (2013). The first term in the brackets in the numerator of (5) is the capital cost recovery factor.

The average retail price for electricity is defined as a fixed markup over average costs of generation:

$$P_{it}=AC_{it}+M_{i2013} \qquad (6)$$

where M_{i2013} is the margin for transmission and distribution costs to customers in 2013. The base case model consists of equations (1)-(6).

For existing fossil fuel generation plants, actual observed heat rates and observed prices paid by electricity companies are used to calculate operating costs by state. Operating costs are simply the product of heat rates and the cost of fuels. Heat rates and operating costs in 2013 are reported in Tables M4 and M5 respectively.

Capital and maintenance costs for existing coal, natural gas, and nuclear power plants are reported in Table M6 based upon Stacy and Taylor (2015) who collected actual observed costs for existing power plants based upon data reported by the Federal Energy Regulatory Commission (2016). Levelized costs from 2016 to 2040 are projected on the basis of forecasts from the Energy Information Administration (2015).

Table M4: Heat Rates for Fossil Fuel Generation

	HEAT RATES IN MILLION BTU / MWH		
States	**Coal**	**Natural Gas**	**Oil**
Colorado	10.58	8.77	10.39
Delaware	11.81	7.37	8.89
North Carolina	10.03	7.25	10.39
New Mexico	10.57	8.57	11.04
Nevada	10.89	7.57	10.45
Oregon	9.80	7.28	9.58
Pennsylvania	10.23	7.56	8.50
Rhode Island	NA	7.79	6.93
South Carolina	10.00	8.09	10.18
Utah	9.92	7.75	10.11
Virginia	10.63	7.83	9.89
Wisconsin	10.41	7.69	4.29

Table M5: Fuel Operating Costs for Fossil Fuel Generation, 2013

	FUEL OPERATING COSTS 2013 $ / MWH		
States	**Coal**	**Natural Gas**	**Oil**
Colorado	20.21	41.04	245.29
Delaware	37.81	29.76	192.04
North Carolina	38.12	36.16	234.41
New Mexico	24.41	36.27	269.67
Nevada	29.84	32.34	254.10
Oregon	19.21	27.72	211.35
Pennsylvania	25.27	30.26	200.84
Rhode Island	NA	44.03	152.35
South Carolina	37.48	37.05	235.13
Utah	20.24	30.76	226.91
Virginia	35.28	32.50	184.18
Wisconsin	24.14	33.76	35.64

Table M6: Capital and Maintenance Costs Fossil Fuel and Nuclear Plants, 2013

	2013 DOLLARS PER MWH					
	Coal		Natural Gas		Nuclear	
States	CapEx	O&M	CapEx	O&M	CapEx	O&M
Colorado	4.60	6.62	9.61	7.09		
Delaware	6.08	6.55	5.47	5.03		
North Carolina	7.91	5.33	5.47	5.03	5.54	14.19
New Mexico	3.10	5.91	5.47	5.03		
Nevada	15.92	13.96	5.83	4.60		
Oregon	6.27	6.47	4.81	4.35		
Pennsylvania	4.59	4.45	5.47	5.03	3.84	18.15
Rhode Island	6.08	6.55	5.47	5.03		
South Carolina	9.40	4.83	3.50	2.79	2.24	15.42
Utah	6.08	6.55	5.47	5.03		
Virginia	5.88	6.54	5.47	5.03	4.76	11.51
Wisconsin	5.41	8.04	5.47	5.03	7.81	23.81

The high oil and gas scenario, which results in relatively low natural gas prices, is used as the base case in this study because the EIA's reference case scenario consistently over-estimates natural gas prices in recent years, as Figure 1 illustrates. Nevertheless, the models are computed using the EIA reference case with higher fossil fuel prices and the results are compared in Appendix B.

Figure 2 presents the twelve state average projected levelized generation costs for existing coal and natural gas plants and for new NGCC plants. Notice that all three series are relatively close with NGCC costs the lowest due to greater thermal efficiency than existing fossil fuel plants. Levelized costs for new NGCC capacity are lowest given its high efficiency. Coal fired generation costs are highest given relatively low natural gas prices in the base case scenario. The cost for hydroelectric generation is \$14.70 per Mwh, based upon observed data reported by Stacy and Taylor (2015). Generation from petroleum-fired capacity is computed on the basis of observed heat rates and oil prices and maintenance and capital recovery costs of \$10.50 per MWh reported by Stacy and Taylor (2015).

The levelized costs for wind generation, c_{iwnt}, are defined as follows:

$$c_{iwnt} = \frac{p_{wnt} K_{wn} \left[\frac{r(1+r)^t}{(1+r)^t - 1} + OM_{wn} \right]}{\left[K_{wn} U_{iwn} \times 365 \times 24 \right]} - \tau_{wn}$$

where p_{wnt} is equal to \$2,213 per KW for capital construction costs in 2013, OM_{wn} is \$39.55 per KW for operation and maintenance costs, K_{wn} is 100 megawatts, and the capacity factors, U_{iwn}, are reported below in Table M7 based upon data from EIA (2016). Note that levelized costs for wind are reduced by the production tax credit for wind power, τ_{wn}, which is equal to \$23 / MWh.

Notice the wide dispersion in capacity factors for wind across states. Windier western states have generally higher capacity factors compared to the eastern regions of the US. The highest wind capacity factor is in Colorado followed by Pennsylvania,

Figure 1: EIA Forecast Accuracy of Henry Hub Prices

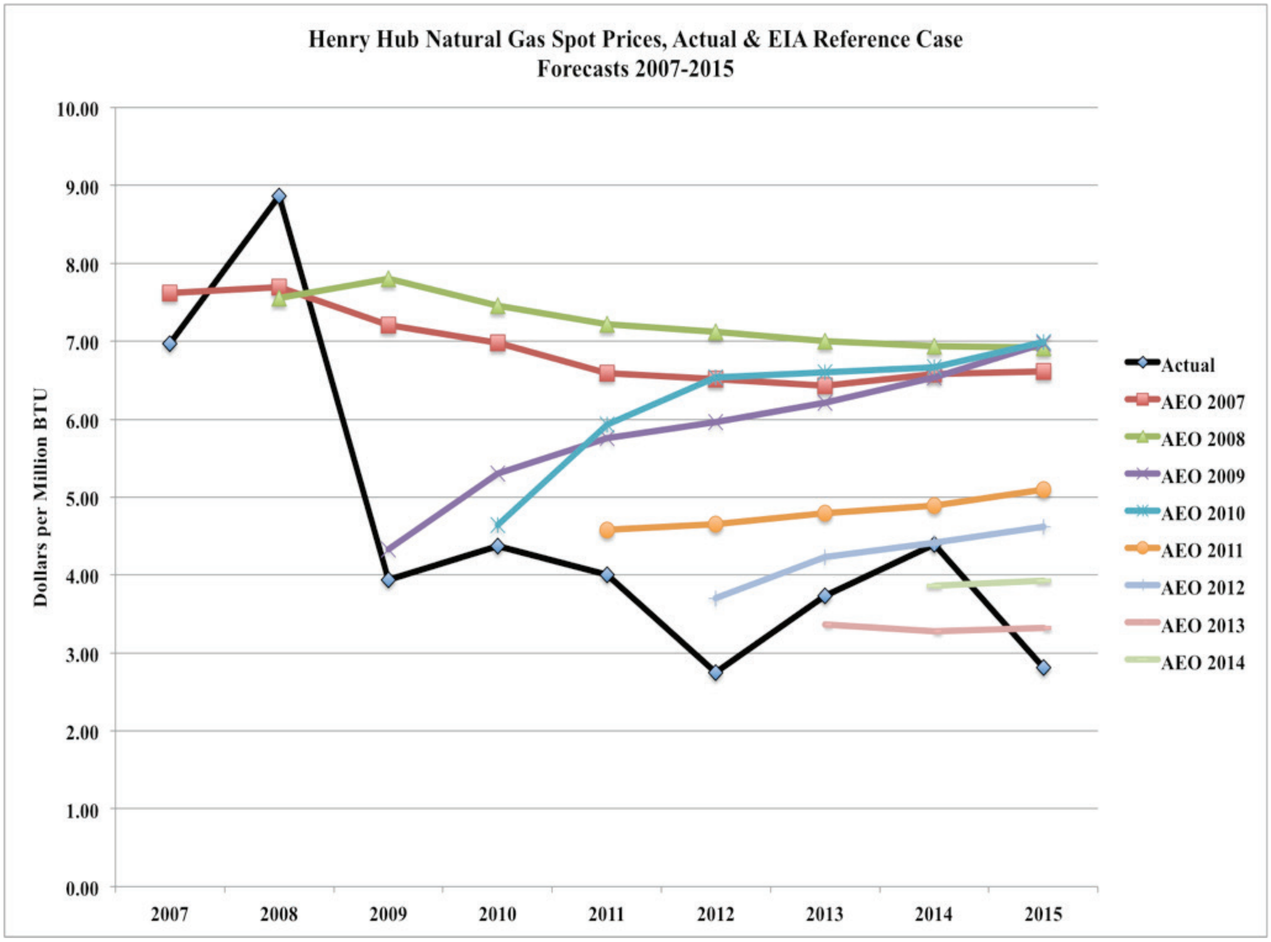
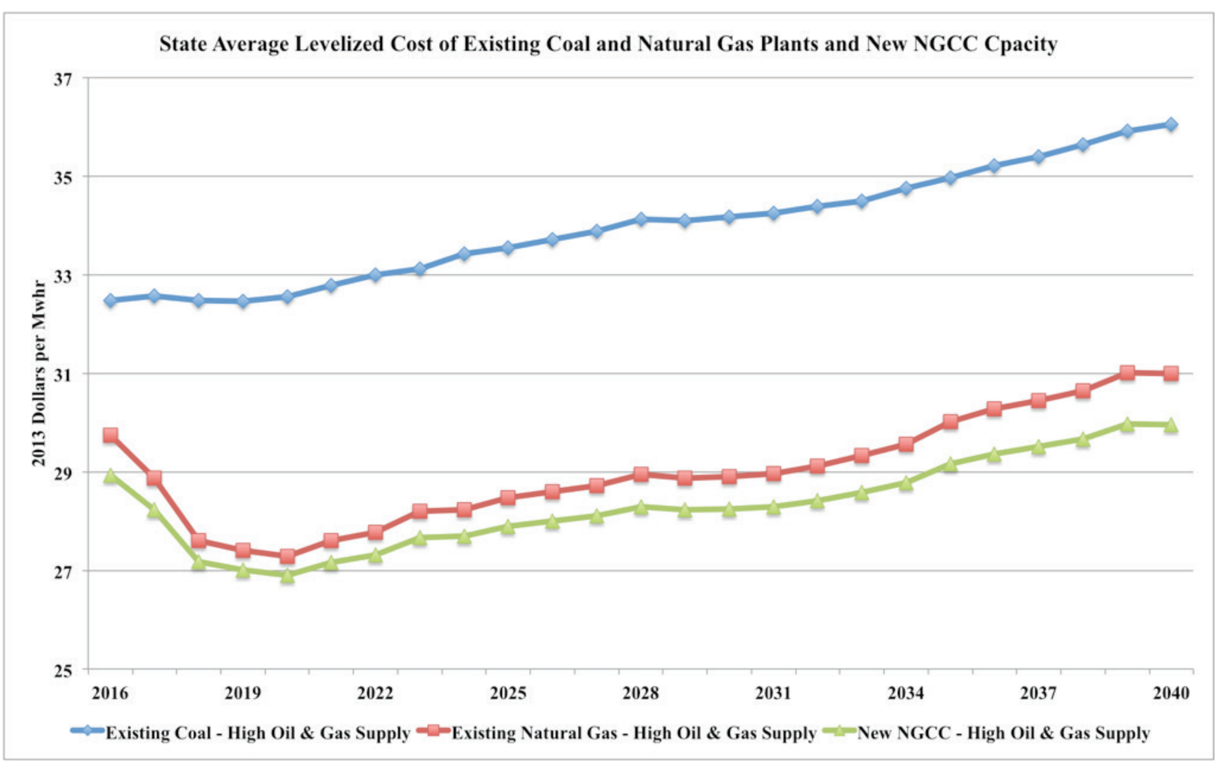


Figure 2: Projected Levelized Costs for Fossil Fuel Generation, 2016-2040



New Mexico, Wisconsin, and Oregon. Also, reported in Table M7 are the shares of new capacity supplied by wind for each state. These shares are determined based upon recent and planned mix of renewable capacity. Wind power is likely to play a major role in meeting RPS goals in Colorado, New Mexico, Oregon, Pennsylvania, Rhode Island, and Wisconsin.

The levelized costs for wind power appears in Table M8. Wind power technology is reaching maturity as noted by EIA (2013), so future overnight capital costs are assumed to decline 0.3 percent annually from 2016 to 2040. This reduces wind power costs by slightly more than 7.7 percent over the forecast horizon.

The levelized costs for solar photovoltaic generation, is defined as follows:

$$|c_{islt} = \frac{p_{slt}\tau_{sl}K_{sl}\left[\frac{r(1+r)^t}{(1+r)^t-1}+OM_{sl}\right]}{\left[K_{sl}U_{isl}\times 365\times 24\right]}$$

where p_{isl} is equal to \$2,479 per KW for capital construction costs, OM*sl* is \$39.90 per KW for operation and maintenance costs, K_{sl} is 150 megawatts, τ_{sl} is the investment tax credit of 30 percent, and the capacity factors, U_{isl}, are reported in Table M7 based upon data from EIA (2016). Given the lack of wind resources, most new renewable capacity is supplied by solar in some eastern states, such as Delaware, the Carolinas, and Virginia.

Projected levelized costs for solar power assume a 1.5 percent annual decline, which reduces solar costs by 30 percent from 2016 to 2040. Also note that the projected levelized costs for solar assume the investment tax credit remains in place. Despite this favorable treatment, levelized costs for several states, such as North Carolina, Rhode Island, and South Carolina are substantially higher than other states due to relatively low solar capacity factors.

Grid Disruption Costs

Additional renewable electricity generation displaces coal and natural gas generation and reduces

Table M7: Capacity Utilization and Shares of New RPS Capacity

	CAPACITY UTILIZATION		SHARES OF RPS CAPACITY	
State	Wind	Solar	Wind	Solar
Colorado	0.353	0.233	0.448	0.552
Delaware	0.255	0.180	0.909	0.091
North Carolina	0.151	0.117	0.885	0.115
New Mexico	0.322	0.233	0.110	0.890
Nevada	0.191	0.230	0.873	0.127
Oregon	0.269	0.219	0.036	0.963
Pennsylvania	0.285	0.153	0.018	0.982
Rhode Island	0.151	0.132	0.437	0.563
South Carolina	0.351	0.132	0.500	0.500
Utah	0.217	0.184	0.735	0.265
Virginia	0.151	0.117	0.680	0.320
Wisconsin	0.280	0.132	0.020	0.980

Table M8: Projected Levelized Costs for Wind Power by State, 2016-2040

LEVELIZED COSTS AFTER WIND TAX CREDIT 2013 DOLLARS PER MWH						
State	**2016**	**2020**	**2025**	**2030**	**2035**	**2040**
Colorado	44.47	43.61	42.55	41.51	40.48	39.47
Delaware	70.52	69.33	67.86	66.42	65.00	63.60
North Carolina	134.84	132.83	130.35	127.91	125.51	123.15
New Mexico	50.92	49.98	48.82	47.68	46.55	45.45
Nevada	101.81	100.22	98.26	96.34	94.44	92.57
Oregon	65.42	64.29	62.90	61.54	60.19	58.87
Pennsylvania	60.60	59.54	58.23	56.93	55.66	54.41
Rhode Island	134.84	132.83	130.35	127.91	125.51	123.15
South Carolina	180.55	177.96	174.76	171.62	168.52	165.48
Utah	86.58	85.19	83.47	81.78	80.11	78.47
Virginia	134.84	132.83	130.35	127.91	125.51	123.15
Wisconsin	61.92	60.83	59.50	58.19	56.90	55.63

Table M9: Projected Levelized Costs for Solar Power by State, 2016-2040

LEVELIZED COSTS AFTER SOLAR INVESTMENT TAX CREDIT 2013 DOLLARS PER MWH						
State	**2016**	**2020**	**2025**	**2030**	**2035**	**2040**
Colorado	77.32	72.79	67.49	62.58	58.02	53.80
Delaware	99.83	93.97	87.13	80.79	74.91	69.46
North Carolina	153.92	144.89	134.35	124.57	115.50	107.10
New Mexico	77.46	72.91	67.61	62.69	58.12	53.89
Nevada	78.30	73.71	68.34	63.37	58.76	54.48
Oregon	82.38	77.55	71.91	66.67	61.82	57.32
Pennsylvania	118.01	111.09	103.01	95.51	88.56	82.11
Rhode Island	136.22	128.23	118.90	110.25	102.22	94.78
South Carolina	136.22	128.23	118.90	110.25	102.22	94.78
Utah	97.66	91.93	85.24	79.04	73.29	67.95
Virginia	153.92	144.89	134.35	124.57	115.50	107.10
Wisconsin	136.22	128.23	118.90	110.25	102.22	94.78

the operational efficiency of existing fossil fuel facilities. To estimate these impacts, this study uses an open-access tool available from EPA (2014). This modeling tool is based upon statistical analysis by Fisher, et al. (2015) of the behavioral characteristics of individual electric generation units (EGUs) from publicly available hourly historical generation and emissions data. This tool tracks the generation and heat rates for each fossil EGU within ten separate electricity generation systems within the US.

For this study, this tool is used to simulate coal and natural gas generation displaced by renewable electricity generation. The percentage changes in heat rates for coal and gas generation are also estimated for various RPS goals. The AVERT tool is simulated for each region and state combination under four different RPS shares from one to twenty percent. Quadratic functions are then fitted to these model outcomes to estimate how fossil fuel displacement shares and the percentage changes in coal and natural gas heat rates adjust as the share of renewable energy approach the RPS goals presented in Table M10.

The average fossil fuel generation displacement shares and percentages changes in heat rates from the RPS goals are summarized in Table M11. For example, on average a megawatt of renewable electricity generation displaces 0.7337 megawatts of coal-fired electricity generation and 0.2663 megawatts of natural gas generation in Pennsylvania. Likewise, the RPS goals for coal heat rates in Pennsylvania are 1.11 percent higher than the base case without RPS while the corresponding heat rates for natural gas are 1.64 percent higher.

The shares of coal and natural gas generation displaced by renewables vary by state based upon the mix of capacity within each region. Likewise, heat rates also vary depending upon the existing level of renewable generation. States with higher levels of existing or legacy RPS generation, such as Colorado and Wisconsin, face higher increases in heat rates with additional levels of RPS generation. These displacement rates and percentage changes in heat rates are used to compute average system wide costs under RPS, which are now discussed.

Table M10: RPS Goals by State

	RPS GOAL	YEAR
Colorado	21.5%	2020
Delaware	22.7%	2026
North Carolina	11.9%	2020
New Mexico	15.7%	2021
Nevada	25.0%	2025
Oregon	50.0%	2040
Pennsylvania	7.8%	2021
Rhode Island	14.5%	2019
South Carolina	2.1%	2021
Utah	20.0%	2025
Virginia	6.0%	2025
Wisconsin	10.0%	2016

Table M11: Average Fossil Fuel Displacement and Changes in Heat Rates from RPS

	RPS DISPLACEMENT SHARES		% CHANGE IN HEAT RATES	
States	**Coal**	**Natural Gas**	**Coal**	**Natural Gas**
Colorado	0.5546	0.4454	6.78%	14.05%
Delaware	0.6960	0.3040	0.09%	0.14%
North Carolina	0.4932	0.5068	0.44%	0.58%
New Mexico	0.2412	0.7588	0.66%	2.81%
Nevada	0.4627	0.5373	1.22%	2.62%
Oregon	0.4908	0.5092	1.92%	4.11%
Pennsylvania	0.7337	0.2663	1.11%	1.64%
Rhode Island	0.1343	0.8657	0.55%	0.42%
South Carolina	0.4931	0.5069	0.12%	0.18%
Utah	0.4973	0.5027	1.18%	2.51%
Virginia	0.4531	0.5469	0.50%	0.83%
Wisconsin	0.8183	0.1817	2.15%	10.26%

Average Costs under RPS

Under renewable energy portfolio standards, new renewable electricity generation is given by:

$$R_{it} = \rho_{it} Q_{it} - \left(G_{islt} + G_{iwnt}\right) \geq 0$$

The inequality on the right indicates that new renewable generation is either positive or zero. Under the RPS, the equation for new generation from natural gas combined cycle capacity is given by:

$$G_{inct} = Q_{it} - B_{it} - G_{it} - R_{it}$$

Hence, the RPS standard reduces the need for additional new natural gas combined cycle capacity and generation. So while additional renewable generation would raise costs, some of these additional expenditures would be offset by lower outlays for new natural gas combined cycle generation to meet future electricity demand growth.

An additional benefit would occur from reduced generation from coal and natural gas powered generation units, D_{iclt} and D_{ingt}, respectively, which are calculated as follows:

$$D_{iclt} = \delta_{iclt} R_{it}$$
$$D_{ingt} = \delta_{ingt} R_{it}$$

where δ_{iclt} and δ_{ingt} are the shares of renewable generation displacing existing coal and natural gas generation summarized in Table M11. Total generation from existing capacity, therefore, becomes:

$$G_{it}^{rps} = \sum_{j \neq cl,ng} G_{ijt} - D_{iclt} - D_{ingt}$$

Additional electricity generation from renewable sources, however, would impose cycling costs on existing generation capacity to accommodate the intermittency of renewable generation. These costs raise the heat rates for existing coal and natural gas capacity. In this case, the levelized costs for existing coal and natural gas generation are defined as:

$$c_{iclt}^{rps} = \left(1+\theta_{iclt}\right) H_{iclt} w_{iclt} + x_{iclt} + o_{iclt}$$
$$c_{ingt}^{rps} = \left(1+\theta_{ingt}\right) H_{ingt} w_{ingt} + x_{ingt} + o_{ingt}$$

where θ_{iclt} and θ_{ingt} are the percentage increases in heat rates, defined as million British Thermal Units (BTUs) per megawatt hour (MWh) summarized in Table M11, and $\chi_{iclt,}\ \chi_{ingt,}\ o_{iclt,}\ o_{ingt}$ are capital expenses and operating and maintenance costs per MWh for existing coal and natural gas generation respectively.

Average generation costs under the RPS scenario, therefore, is as follows:

$$AC_{it}^{rps} = \frac{\left[\sum_{j \neq cl,ng} c_{ijt} G_{ijt} + c_{inct} G_{ingt} + c_{iclt}^{rps}\left(G_{iclt} - D_{iclt}\right) + c_{ingt}^{rps}\left(G_{ingt} - D_{ingt}\right) + c_{irt} R_{it}\right]}{G_{it}^{rps} + G_{inct}^{rps} + R_{it}}$$

where c_{irt} is a weighted average the levelized costs generation from of solar and wind capacity. These weights vary by state and are based upon observations on capacity and generation in 2013.

Finally, retail electricity prices under the RPS are given by:

$$P_{it} = AC_{it}^{rps} + M_{i2013}$$

In summary the RPS model is given by the demand equation (1) and the electricity supply model given by (9)-(15).

Net Costs of RPS

The costs of the RPS goals are estimated by calculating the difference in retail electricity expenditures between the base case and the RPS scenarios for each state. To understand the sources of changes in costs arising from the RPS goals a cost decomposition is calculated for each state.

The first component of this decomposition is the cost associated with existing renewable energy capacity, which is assumed to be the result of RPS goals implemented prior to 2016. These costs are called net RPS legacy costs and include the direct costs of operating legacy RPS capacity including cycling costs less fuel cost savings arising from the displacement of coal and natural gas generation by renewable electricity generation.

The second component of the costs of RPS policies is incurred in the future as higher RPS goals are met. These are costs are defined the same as RPS legacy costs except avoided NGCC costs are included.

The third cost component is the cost of federal renewable energy subsidies. For wind power the subsidy is the $23 per megawatt hour production tax credit. Similarly, solar electricity generation units receive a 30 percent investment tax credit.

The total costs of RPS goals equal RPS legacy costs plus new RPS costs and subsidies. Reductions in carbon dioxide emissions are also calculated based upon the two scenarios and the direct (both legacy and new RPS) costs and subsidies per ton of avoided emissions are calculated.

Economic Impacts

The changes in electricity prices and investments in both renewable energy and NGCC capacity will affect regional value added and employment. Changes in value added and employment for a 10 percent increase in electricity prices are presented in Tables M12 and M13 based upon the econometric analysis conducted by Patrick et al. (2015). These estimates vary by state and industry so that the economic impacts of electricity price changes vary by state based in part upon the mix of industries.