Modeling Long-Run Demand Response in Electricity Markets with Carbon Markets

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Introduction

Estimating the effects and efficacy of legislation aimed at reducing carbon emissions in the United States must address both economics and engineering concerns. In the absence of engineering constraints, any modeling of the electrical system is incomplete, and ignores constraints imposed by generating plants and power lines. Ignoring economic constraints in the presence of deregulated electricity markets is likewise unrealistic. Estimating the demand response to increased electricity prices which is necessary to adjust load (and in turn the output of various emissions) is vital to such analysis. Although there is little or no demand response in the short run, long term planning, such as is necessary to build new power plants, requires the accurate forecasts of demand and electricity prices.

In this paper, we set out to analyze the effects of the proposed American Clean Energy and Security Act of 2009 (ACESA) introduced by Henry Waxman and Edward Markey, and the proposed American Power Act, introduced by John Kerry and Joseph Lieberman. Although our analysis is limited to the northeastern states involved in the Regional Greenhouse Gas Initiative, including observer states and provinces, this small base case is still effective in demonstrating the importance of rigorous engineering constrains combined with demand response.

Background

Our model uses a network reduction of the Northeast United States developed by Allen, Lang and Ilic.[1] Using MATPOWER, the network was modeled to produce least-cost electricity subject to engineering constraints under a variety of assumptions, such as different emission prices, load, drought, etc.. For more detail about this stage of the project, refer to Schulze et al. (2009)[2]

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[1] Eric Allen, Jeffrey Lang, and Marija Ilic, “A Combined Equivalenced-Electric, Economic & Market Representation of the Northeastern Power Coordinating Council (NPCC) US Electric Power System,” IEEE Transactions on Power Systems, Vol. 3, Issue 3, 2008

[2] “Facilitating Environmental Initiatives While Maintaining Efficient Markets and Electric System Reliability.” Schulze, William, Robert Thomas, Timothy Mount, Richard Schuler, Ray Zimmerman, Dan Tylavsky, Dan Shawhan, Doug Mitarotonda, John Taber. PSERC Document 09-9, October 2009. http://www.pserc.wisc.edu/documents/publications/reports/2009_reports/schulze_emissions_pserc_m-20_final_report_oct2009.pdf

The states and provinces modeled in this study differ somewhat in generating capacity from the rest of the United States, having somewhat less coal and substantially more zero-carbon sources, such as hydropower and nuclear, as shown in Table 1.

Table 1: Comparison of Generation between our model and the United States

	Model	United States
Coal	29%	49%
Hydropower	10%	6%
Natural Gas	20%	21%
Nuclear	37%	20%

We take the output from the MATPOWER simulations and fit a multi-equation statistical model to estimate quantities of carbon dioxide, sulfur dioxide, nitrous oxides, and average nodal electricity prices with linear regressions, given the prices of the various pollutants and electricity loads as an input. The subscript i represents carbon dioxide for i=1, sulfur dioxide for i=2, and nitrous oxides for i=3.

$$Q_i = \alpha_i + \beta_{i,1} \text{ x } P_1 + \beta_{i,2} \text{ x } P_2 + \beta_{i,3} \text{ x } P_3 + \gamma_I \text{ x Load} \qquad (1\text{-}3)$$

$$\text{LMP} = \alpha_4 + \beta_{4,1} \text{ x } P_1 + \beta_{4,2} \text{ x } P_2 + \beta_{4,3} \text{ x } P_3 + \gamma_4 \text{ x Load} \qquad (4)$$

The quantity emitted of each pollutant as well as the average wholesale price (LMP) depends on the prices of all three pollutants, as well as the aggregate system load.

We also model demand response to changing electricity prices while assuming constant load growth of 0.59%, based on estimates from the New York ISO.[3] WLMP represents the effective average retail price of electricity.

$$\text{Load}_t = \theta \text{ x } ((\text{WLMP}_t - \text{WLMP}_{t-1})/\text{WLMP}_{t-1}) \text{ x Load}_{t-1} + (1.0059 \text{ x Load}_{t-1}) \qquad (5)$$

This last equation is the cornerstone of our demand response, which is useful for calculating a long-run equilibrium in the electric power market. In the short run, demand response is negligible, as customers, especially residential customers, are often tied into fixed-rate price contracts. In the long run, the elasticity of demand is close to -1[4], as rates adjust and customers have time to make energy-efficiency investments. Weighted LMP, $\text{WLMP}_{t,}$ is an infinite exponentially decreasing distributed lag of LMP prices estimated by our model and takes the form:

$$\text{WLMP}_t = ([1-\alpha] \text{ x WLMP}_{t-1}) + (\alpha \text{ x } (75+\text{LMP}_{t-1})) \qquad (6)$$

The 75 being added to LMP accounts for distribution costs, the difference between the wholesale cost of electricity, given by LMP, and the effective retail price of electricity, which is the WLMP. We test two values for α: 0.1 and 0.2, to test two

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[3] http://www.nyiso.com/public/webdocs/newsroom/press_releases/2009/NYISO_2009_Summer_Outlook__05212009_(2).pdf

[4] Dahl, Carol. "A Survey of Energy Demand Elasticities in Support of the Development of the NEMS." ftp://ftp.eia.doe.gov/pub/oiaf/elasticitysurvey/elasticitysurvey_dahl.pdf

different ranges of demand response. Using this equation, load will not immediately adapt to changes in prices, and the impact of systemic price changes will be gradually adopted. This is motivated by the rate of appliance upgrades in the United States. For example, the median age for a primary refrigerator in the United States is five to nine years.[5] An alpha of 0.1 corresponds to a median age of electricity usage patterns (equipment or conservation habits) of seven years. In response to rising electricity costs, households may buy a more energy efficient appliance with those purchases.

Using the results from an OLS estimation (covered later in the paper) of equations (1) – (4) and incorporation equations (5) and (6) allows us to model the quantity of carbon dioxide and other pollutants produced as carbon dioxide permit prices are changed. Alternatively, we can examine what prices are necessary to meet carbon targets as specified in each proposed bill. The algorithm for estimating works as follows:

1) Given weighted LMP, load is estimated for the current year (t)
2) Given load and emission prices, pollutant production and LMP for year t are estimated
3) Weighted LMP is calculated for year t+1
4) Return to step (1)

Sixteen simulations were run for each proposed bill to investigate the effect of demand response to changing electricity prices. The speed of demand response, α, was set at 0.1 or 0.2. Carbon dioxide emissions have declined in the northeast since 2005; this creates a "slack" in the reductions required, since emissions in 2011 are expected to be below those required in 2016. Therefore, we also investigate the effects of this slack by setting the slack at 0% or 10%. We alternately hold SO_2 and NO_X emissions prices constant or let quantity regulations on these pollutants determine SO_2 and NO_X prices. Finally, we investigate the effect of applying emissions restrictions to all generating units, or, as is commonly done in the United States, only those larger than 25 MW. Reasonable starting parameters from current electricity grid information were used as seed values for the model. An initial LMP of \$74, a load of 1, CO_2 emissions prices of \$0, and emissions prices for SO_2 of \$392 and NO_X of \$731 were used.

Climate Change Legislation

The proposed American Clean Energy and Security Act of 2009 (ACESA) introduced by Representatives Henry Waxman and Edward Markey, proposes the following reductions in greenhouse gas emissions:

1% below 2005 levels by 2012
17% below 2005 levels by 2020
36% below 2005 levels by 2030
55% below 2005 levels by 2040

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[5] "U.S. Household Electricity Report." http://www.eia.doe.gov/emeu/reps/enduse/er01_us.html

73% below 2005 levels by 2050

The "below 2005" baseline produces some interesting results in the analysis, because greenhouse gas emissions have fallen below 2005 levels, mostly due to improvements in energy efficiency and the recent recession. The ACESA includes more restrictions on greenhouse gas emissions, such as a banking system, like that currently used in the EPA's Acid Rain program. In addition, the ACESA sets a floor on CO2 prices, which starts at $10 per ton in 2012, and increases by 5% each year in real terms.

Under the American Power Act, introduced by Senators John Kerry and Joe Lieberman, the carbon cap decreases by 1.8% from 2011 levels until 2020, and then 2.5% per year. Thus, the carbon cap is 17% below 2011 levels by 2020 and 29.5% below 2011 levels by 2025. In addition, the American Power Act also has a price floor that starts at $12/ton and increases by 3% each year and a price cap that starts at $25/ton and increases by 5% each year in real dollars.

The requirements for carbon reduction in each bill are similar, but the different structure of prices results in different outcomes for each bill, particularly the imposition of a ceiling on carbon prices in the American Power Act. After the first five to seven years, the price floor on the ACESA is rarely binding, and prices often increase to levels far above the price ceiling in the American Power Act.

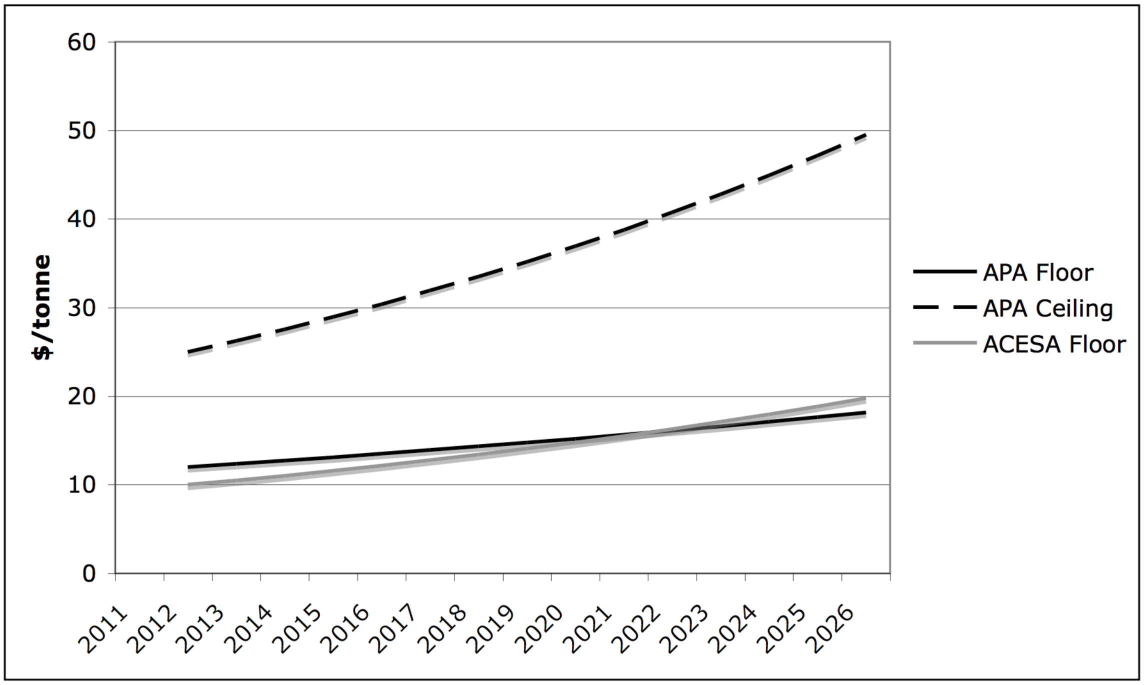

Figure 1: CO2 Price floors and price ceilings under the American Power Act and the American Clean Energy and Security Act

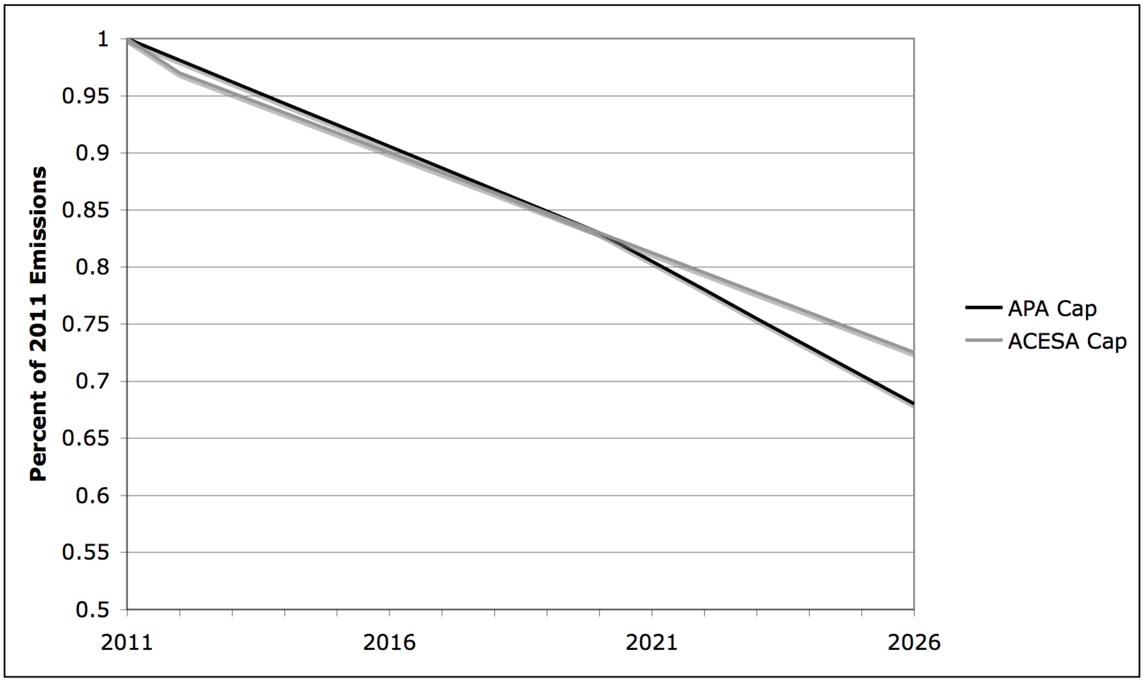

Figure 2: CO2 Emissions under the American Power Act and the American Clean Energy and Security Act (Assuming equal starting points)

Estimation Results

Linear regressions were estimated using relevant portions of 2061 output observations produced by modeling the electric power grid of the Northeast as various factors, such as emissions prices and load were varied, along with assumptions regarding the model, such as whether the emissions restrictions were applied to every power plant in the model, or only those larger than 25 MW. Each regression below includes 140 observations from the output of the model.

Quantities for emissions are in tonnes, emission prices are in dollars per tonne, average LMP is expressed in dollars per megawatt hour, and load is expressed as a fraction of expected load in 2011. (A load of 0.90 would mean that load is 10% lower than in 2011.) Tables 1-4 show the estimated equations for predicting the quantity produced of the three pollutants and average LMP.

Table 2: CO_2 Quantity, Under 25 Exempt

Adjusted R-Squared: 0.98

	Coefficient	T Stat	P-Value
Intercept	-248492039.9	-27.17	1.37E-56
Load	523100792	56.95	2.85E-96
CO_2 Price	-184338.26	-66.64	3.61E-105
SO_2 Price	-1298.01	-2.86	0.0049
NO_X Price	-158.75	-1.05	0.30

Table 3: SO_2 Quantity, Under 25 Exempt

Adjusted R-Squared: 0.97

	Coefficient	T Stat	P-Value
Intercept	-202711.97	-1.48	0.14
Load	1593214.29	11.61	4.94E-22
CO_2 Price	-2588.28	-62.61	1.25E-101
SO_2 Price	-35.61	-5.25	5.88E-07
NO_X Price	-2.55	-1.13	0.26

Table 4: NO_X Quantity, Under 25 Exempt

Adjusted R-Squared: 0.93

	Coefficient	T Stat	P-Value
Intercept	-168375.07	-8.96	2.25E-15
Load	392732.33	20.82	5.65E-44
CO_2 Price	-197.98	-34.85	2.35E-69
SO_2 Price	-2.28	-2.44	0.016
NO_X Price	-2.22	-7.12	5.67E-11

Table 5: LMP, Under 25 Exempt

Adjusted R-Squared: 0.99

	Coefficient	T Stat	P-Value
Intercept	-110.84	-23.38	2.59E-49
Load	174.12	36.57	6.53E-72
CO_2 Price	0.70	487.89	4.94E-221
SO_2 Price	0.0019	8.18	1.86E-13
NO_X Price	0.00044	5.65	8.96E-08

Table 6: CO_2 Quantity, All Units Covered

Adjusted R-Squared: 0.98

	Coefficient	T Stat	P-Value
Intercept	-243906746.3	-27.01	2.74E-56
Load	518642080.4	57.18	1.69E-96
CO_2 Price	-195045.61	-71.40	4.17E-109
SO_2 Price	-1371.36	-3.06	0.0027
NO_X Price	-162.61	-1.09	0.28

Table 7: SO_2 Quantity, All Units Covered

Adjusted R-Squared: 0.97

	Coefficient	T Stat	P-Value
Intercept	-231255.87	-1.70	0.091
Load	1621466.10	11.88	1.018E-22
CO_2 Price	-2527.00	-61.46	1.41E-100
SO_2 Price	-34.96	-5.18	7.93E-07
NO_X Price	-2.52	-1.12	0.27

Table 8: NO_X Quantity, All Units Covered

Adjusted R-Squared: 0.97

	Coefficient	T Stat	P-Value
Intercept	-136532.43	-9.75	2.54E-17
Load	361323.13	25.68	8.27E-54
CO_2 Price	-269.91	-63.70	1.33E-102
SO_2 Price	-2.75	-3.96	0.00012
NO_X Price	-2.20	-9.50	1.062E-16

Table 9: LMP, All Units Covered

Adjusted R-Squared: 0.99

	Coefficient	T Stat	P-Value
Intercept	-114.94	-23.72	5.35E-50
Load	178.03	36.58	6.19E-72
CO_2 Price	0.71	483.72	1.57E-220
SO_2 Price	0.0020	8.48	3.59E-14
NO_X Price	0.00047	5.88	3.11E-08

These results are very much as would be expected. Increasing prices on any pollutant result in a reduction of the quantity produced, as well as the quantity of all other pollutants, most likely because of the simultaneous nature of pollutant production. Especially as prices on CO_2 permits increase, more generation shifts away from coal plants (especially older coal plants) resulting in a drop in other emissions as well.

Results for American Clean Energy and Security Act

In all simulation runs with demand slack, CO_2 prices stayed at the floor set by the ACESA until 2015-2017, depending on other assumptions. With slow demand response, CO2 prices then increase steadily. With fast demand response, CO2 prices oscillate somewhat, returning to the floor occasionally. In simulation runs without demand slack, CO_2 prices increased rapidly in 2012. CO2 prices then oscillate for a few years. With slow demand response, these oscillations settle down to increasing prices, but in the case of fast demand response, these oscillations continue, with CO2 prices alternating between the floor and higher prices. When we include the prices of other pollutants, SO2 prices collapse in 2012. If there is slack in CO2 output, NOX prices increase then decline to zero within a few years. The main effect of covering all units, instead of just large generators is to reduce average CO2 prices by about 1%. Emissions of SO2 and NOX decline to about 72% of 2011 levels by 2026 because of decreased load and the effect of CO2 permit prices.

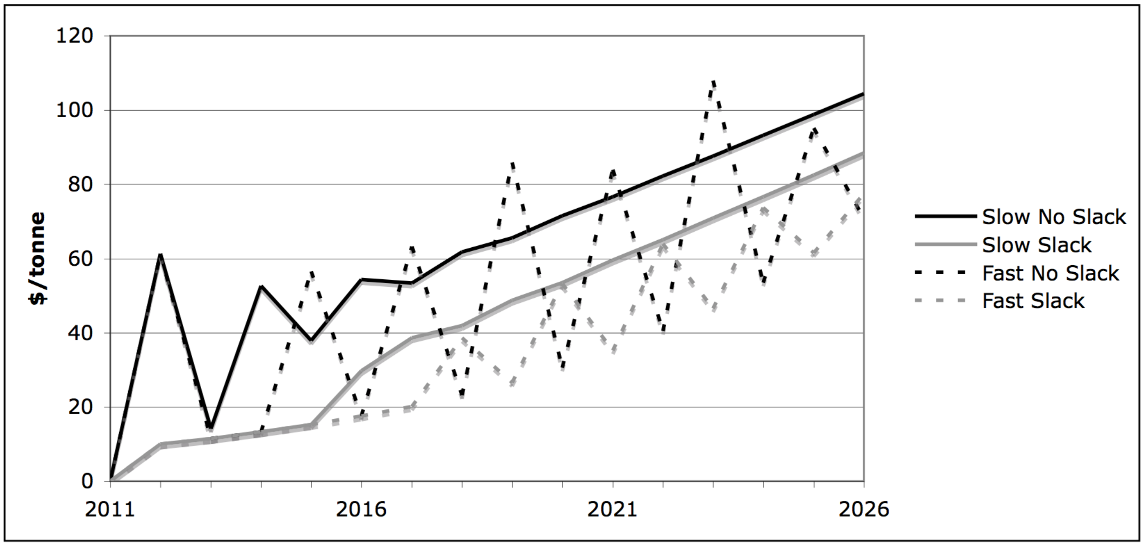

Figure 3: CO2 Prices for Generators < 25 MW Exempt, No Other Emission Prices, ACESA

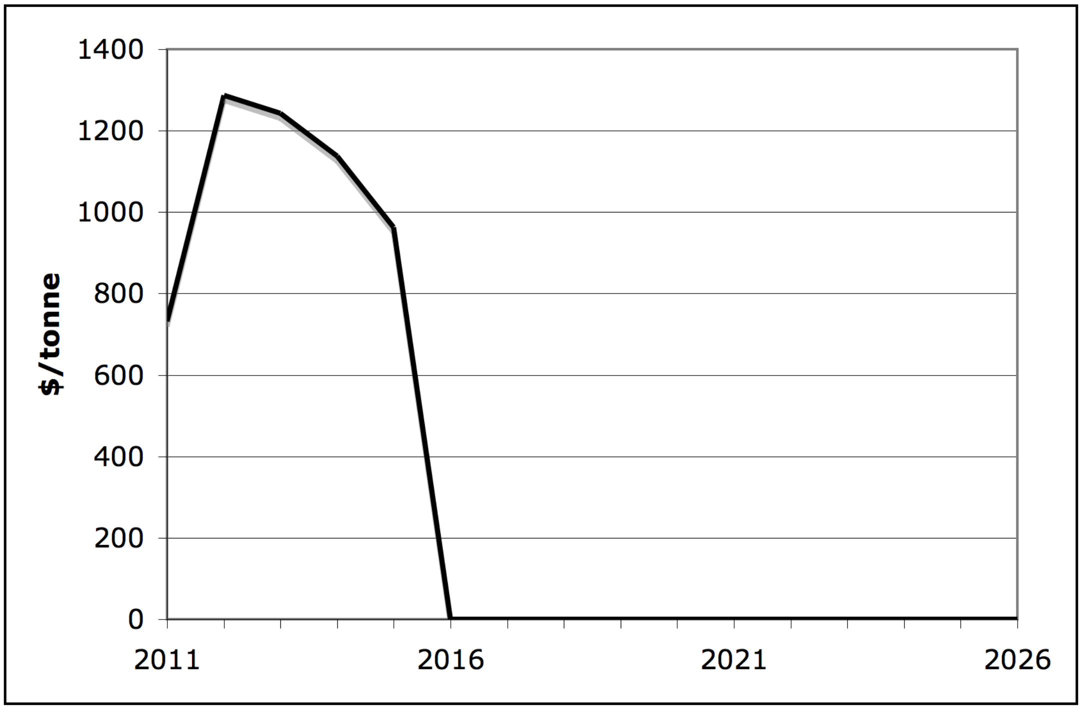

Figure 4: NOx Prices, Generators <25 MW Exempt, Slow Demand Response, CO2 Slack

Under the ACESA, with generators <25 MW Exempt, electricity prices increase and load decreases. Current LMP increases from $64/MWh to $97-$118, depending on model assumptions. Models without slack saw a larger increase in final prices. Additionally, faster demand response produces more volatility in prices. Weighted LMP also increases, from a starting point of $139/MWh to $164-$170, again depending on model assumptions. In 2026, load is 89%-92% of 2011 levels. (Resultant load is lower when demand response is higher.)

When compared to a model without any demand response, the results are even more striking. Assuming constant load growth of 0.59% per year, load in 2026 will be at 109% of the 2011 level. This requires CO2 permit prices to be $567-$673/tonne, and results in current LMP between $476/MWh and $550/MWh. As these estimates for CO2 permit prices are beyond the scope of tested prices for our model, these results have less predictive power than the rest of our estimations.

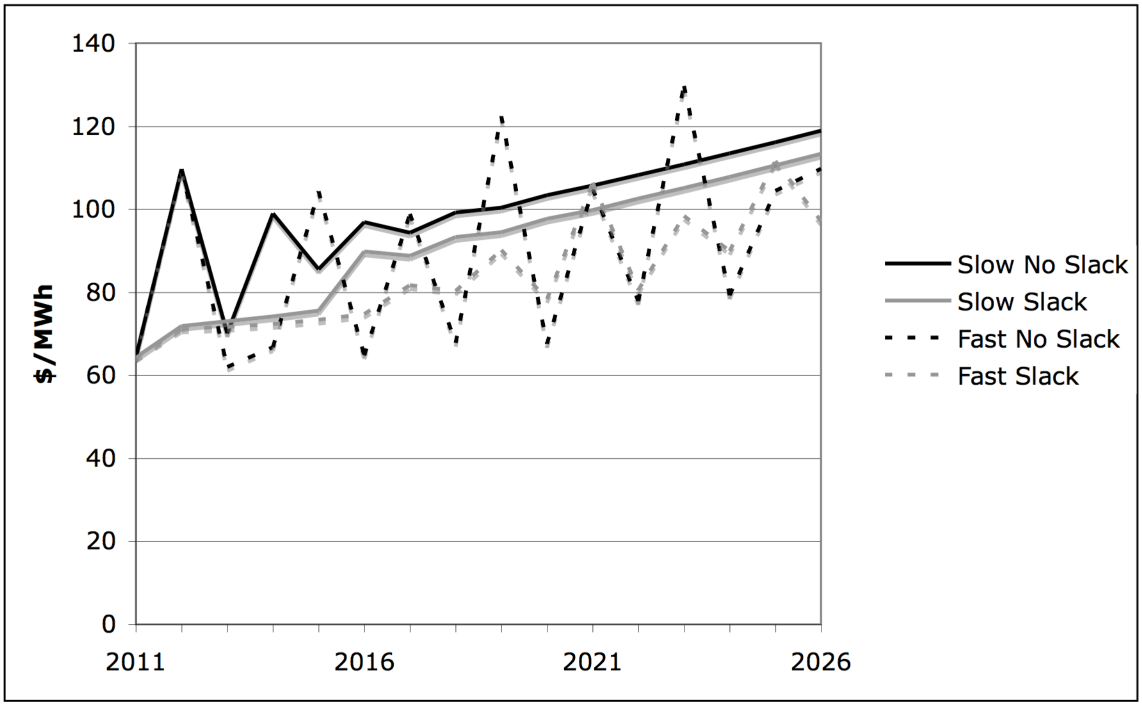

Figure 5: Current LMP for ACESA, Generators < 25 MW Exempt

Results for the American Power Act

The imposition of a carbon ceiling as well as a carbon floor in the APA produces many changes in the cost of carbon permits, electricity prices, load, and resultant carbon emissions. Although the carbon cap is fairly similar to the cap under the ACESA, the carbon price ceiling limits the carbon prices, resulting in carbon emissions greater than the cap – over 30% more by 2026. In simulations with no initial slack in the carbon cap, the carbon emission price jumps immediately to the ceiling and remains there, with the exception of the second year in the case of rapid demand response. In simulations with initial slack, the carbon prices remain at the floor until 2016 or 2017, at which point they increase to the ceiling, except in the case of fast demand response, in which case they oscillate for one year before hitting the ceiling. There is no substantive difference in behavior between simulations in which all units are covered and simulations in which generating units less than 25 MW are exempted.

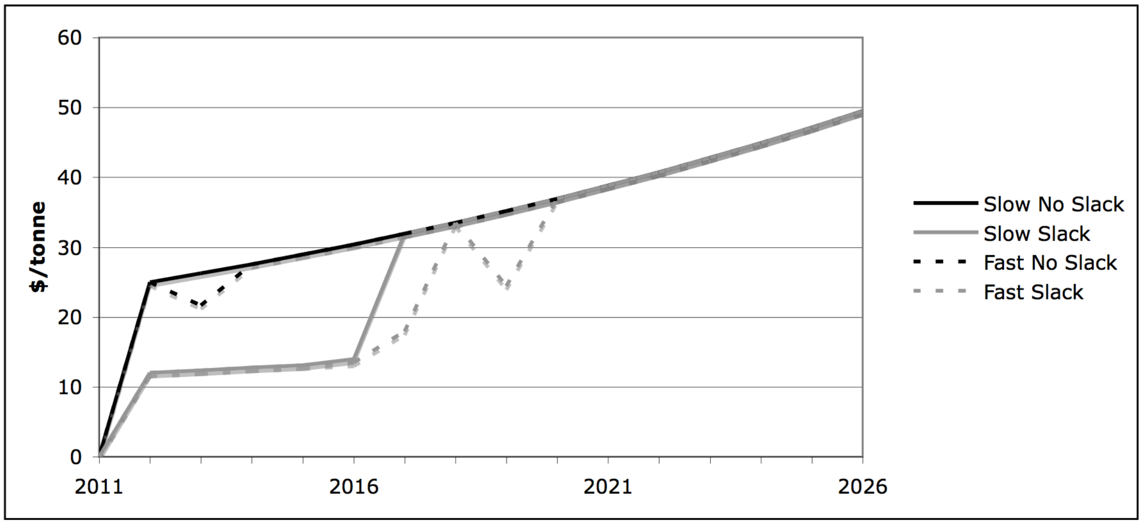

Figure 6: CO2 Prices for Generators < 25 MW Exempt, APA

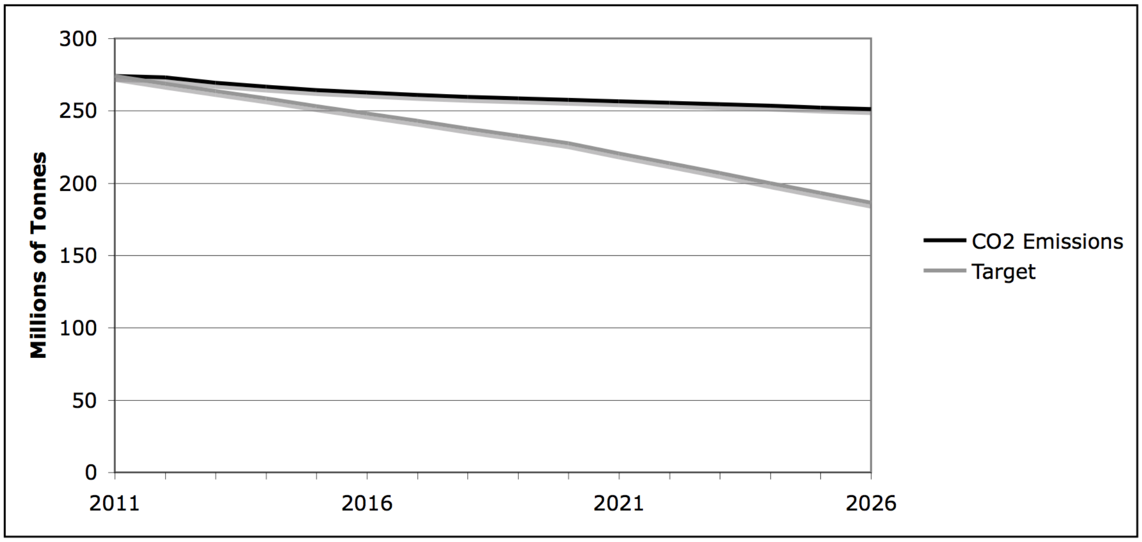

Figure 7: CO2 Emissions under APA for Slow Demand Response, No Slack

The effect of the American Power Act on other emission prices is similar to the ACESA. SO2 prices crash immediately, and NOx prices crash if there is no slack in the carbon cap. If there is slack, and small generators are exempt, prices increase slightly to $1100 and crash in 2017 if demand response is slow and 2013 if demand response is fast. If all units are covered, NOx prices are steady or slightly decline, then crash in 2017 if demand response is slow and 2013 if demand response is high.

Under the American Power Act, load declines to 95% of 2011 levels by 2026 if demand response is fast, and only 97% of 2011 levels if demand response is slow. Compared to the ACESA, higher load in 2026 means that electricity prices are lower, mostly as a side effect of lower carbon prices because of the ceiling imposed by the American Power Act. LMP increases from $64/MWh to $90-$94/MWh. In this case, faster demand response causes less load which in turn reduces final LMP. Weighted LMP is $156-159/MWh in 2026, from a base of $139/MWh.

Comparison of the ACESA and the American Power Act

As shown in this paper, both of these proposed pieces of legislation have markedly different outcomes. Although both the ACESA and the American Power Act reduce carbon output, the ACESA reaches carbon emissions goals through higher prices on carbon emission permits, which ultimately leads to higher electricity prices and lower load. The American Power Act, in comparison, limits the maximum level of carbon prices and thus trades price stability for greater carbon emissions, more load, and lower electricity prices.

Table 10: Comparison of ACESA and the American Power Act: Simulation Results from 2026

	ACESA	American Power Act
Min CO2 Price ($/tonne)	70.76	49.50
Max CO2 Price ($/tonne)	106.30	49.50
Average CO2 Price ($/tonne)	85.05	49.50
Min LMP ($/MWh)	91.44	90.23
Max LMP ($/MWh)	118.88	94.16
Average LMP ($/MWh)	106.72	92.09
Min Weighted LMP ($/MWh)	164.18	156.08
Max Weighted LMP ($/MWh)	170.69	159.61
Average LMP ($/MWh)	167.48	157.89
Min Load (As % of 2011 Load)	88%	95%
Max Load (As % of 2011 Load)	93%	97%
Average Load (As % of 2011 Load)	90%	96%
Min CO2 (As % of Target)	98%	123%
Max CO2 (As % of Target)	100%	135%
Average CO2 (As % of Target)	100%	123%

Emissions Banking

A more realistic model would incorporate emissions banking. Excess emissions permits from one year, purchased directly by electric utilities or by third party traders may be carried forward and used in subsequent years when permit prices are expected to be higher, or used as a hedge against price volatility in carbon dioxide permit prices. Because of the existence of price floors and ceilings in the American Power Act, emissions banking would probably have little effect; when carbon dioxide prices are at the price ceiling, no permits can be banked for future years.

However, the ACESA provides more opportunities for the utilization of permit banking. As a first approximation of the effects of emissions banking, we set the expected present value of carbon permits to be equal (in real terms), accounting for a real rate of return of 7.5%. Thus, electric utilities can equalize their marginal abatement costs across time.

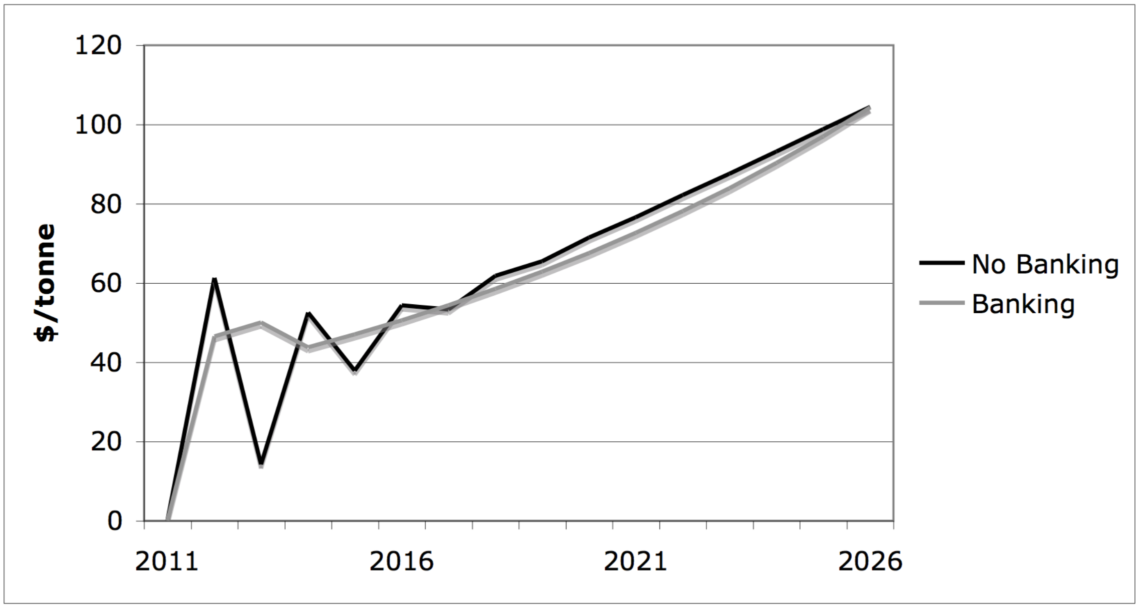

Figure 8: CO2 Prices with and without banking, Generators <25MW Exempt, Slow Demand Response, No Slack

As shown in figure 8, the use of banking can significantly reduce volatility of carbon permit prices, especially early in the time period. As well as reduced volatility, the average price for carbon permits is slightly lower with banking, $67.20/tonne versus $67.70/tonne. The same pattern holds true for wholesale electricity prices (LMP), as seen in Figure 9. Additionally, allowing emissions banking slightly increases the total amount of carbon dioxide produced, on the order of 1-2%, depending on model assumptions because permits from years when carbon prices are higher than necessary because of a floor on emission prices can be carried forward to future years and partially offset some emissions in those years.

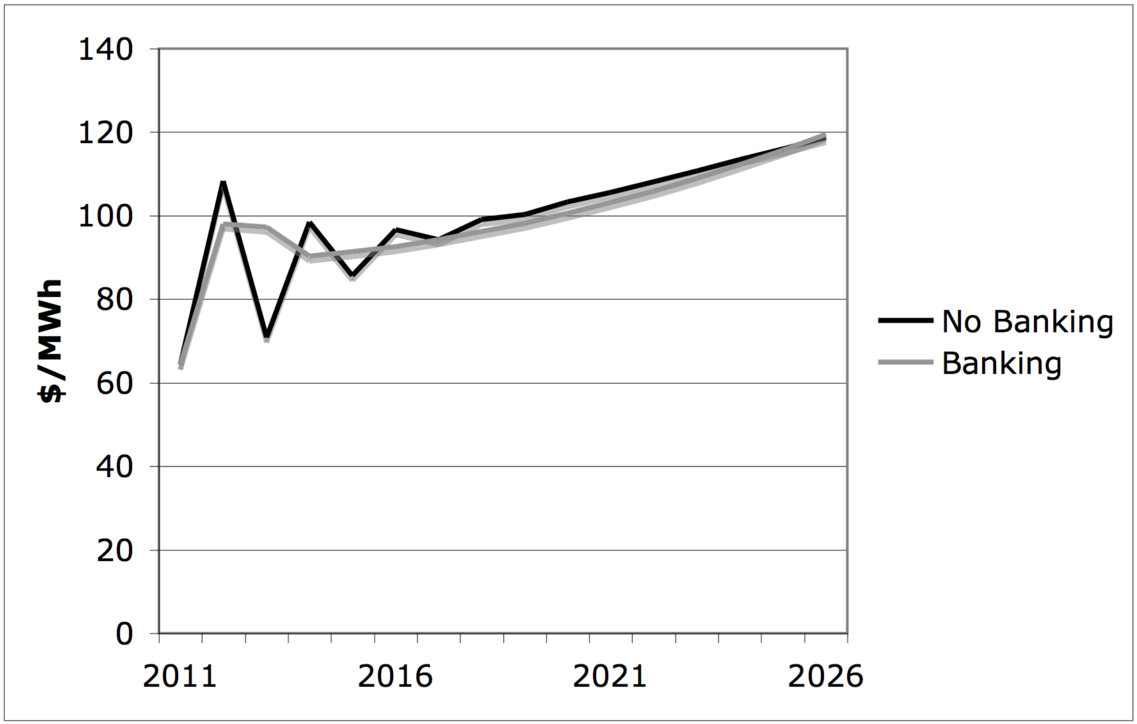

Figure 9: Current LMP, with and without emissions banking, Generators <25 MW exempt, Slow Demand Response, No Slack

In addition, we have examined the impact of different elasticities on the effects of the ACESA. As seen in figures 10 and 11, an elasticity of 0.5 instead of 1 increases carbon dioxide permit prices by, on average, 60% over the time period. As well,wholesale electricity prices increase by, on average, 30%. Despite the larger prices, the reduced responsiveness leads to a load about 2% larger in 2026.

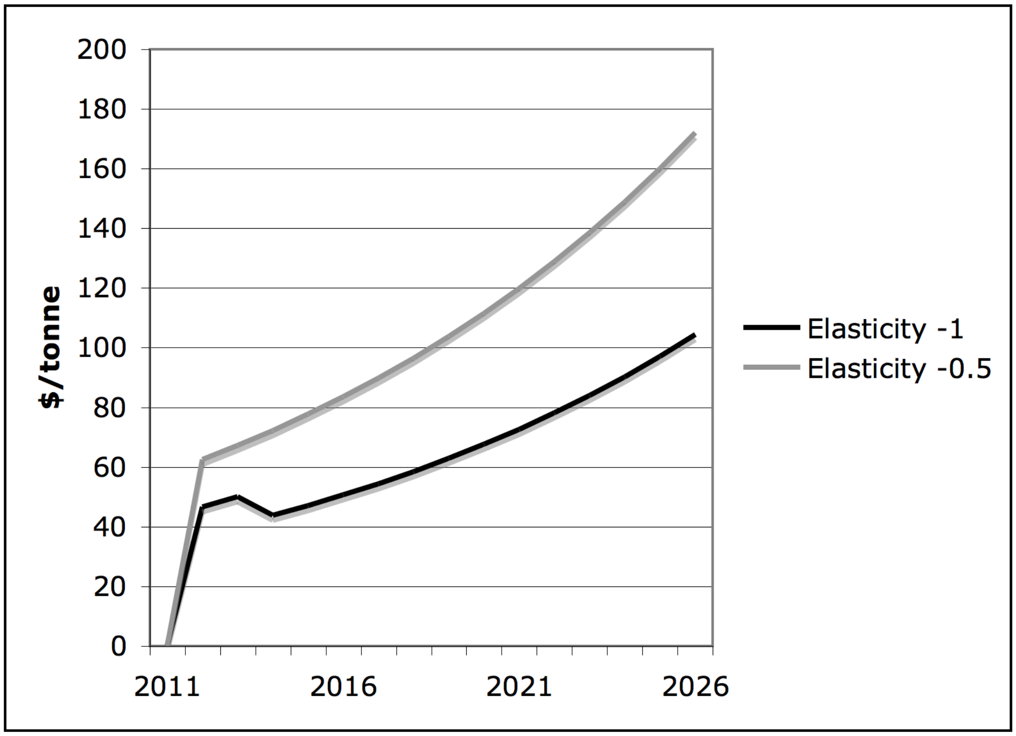

Figure 10: CO2 prices with banking, for two elasticities

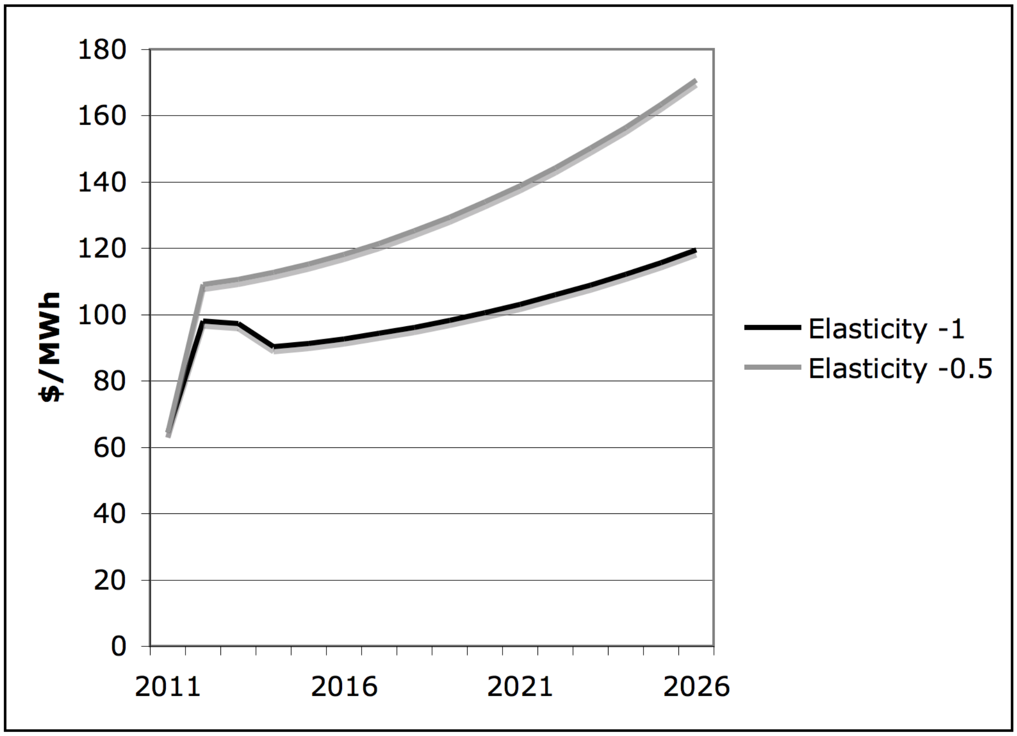

Figure 11: LMP with banking for two elasticities

Summary

In this paper, we have shown the effects from modeling the proposed ACESA and the American Power Act. Both proposed bills reduce carbon emissions, though the ACESA reduces carbon emissions by a greater amount, but requires higher carbon prices and electricity prices to accomplish this. In addition, the variance of carbon prices under the ACESA is greater, which will lead to more uncertainty when making investment decisions in new capacity. By limiting carbon permit prices, the American Power Act reduces volatility in electricity prices and carbon permit prices, at the cost of greater carbon emissions.

These models are not perfect; in particular, they omit a full model of the banking of carbon permits, which is allowed in each bill and may alleviate some of the variance in carbon permit prices seen in the ACESA. However, European carbon markets and the market for sulfur dioxide in the United States still show extreme volatility, so permit banking may not alleviate that problem. Ideally, a model for emissions banking would use banking to reduce the net present cost of system operation, instead of being used to reduce volatility or carry unused permits forward in time.

A larger oversight in the model is the inability to model new capacity additions. Although not available in the short-run, by 2020, new lower-carbon generating units could be brought online. However, the power makeup of the RGGI states is already skewed to less carbon-intensive units than the rest of the United States, which means that its generating profile may be similar to the eventual profile of the rest of the country.