Electricity load and carbon dioxide emissions: effects of a carbon price in the short term

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***Abstract*—Stabilizing atmospheric carbon dioxide levels at acceptable levels will require a dramatic de-carbonization of the electric generation sector in the U.S. One increasingly discussed way to meet this policy goal is to put an explicit price on carbon emissions, either through a tax or a trading scheme. Increasing demand response has also been discussed as a way to reduce carbon emissions in the U.S. electricity industry. We examine the short-run effectiveness of a policy combining demand response with a carbon tax. Using plant-level operational data, we construct short-run cost curves for three U.S. regional electric systems, and examine the impacts on prices and carbon emissions. In the short run, a carbon tax in the range of $30 - $40 and a price elasticity of demand in the range of -0.1 to -0.2 could reduce carbon emissions in coal-intensive regions by 10% to 25%. With this same set of carbon prices, achieving a 50% reduction in emissions would require a price elasticity of demand in the range of -0.25 to -0.4. Percentage reductions of this magnitude in less carbon-intensive systems are unlikely, even with highly elastic demand and high carbon prices.**

***Index Terms*—Climate Change, Carbon Tax, Demand Response**

I. INTRODUCTION

RECENT judicial [1, 2], political [3-5] and industrial [6-11] actions suggest that there may soon be an explicit price on carbon emissions in the US. A price on carbon emissions will increase the price of delivered electricity, as 72 percent of the electricity generated in the U.S. comes from carbon intensive fossil fuels (50 percent from coal) [12]. Previous studies [13-16] have examined the effects of carbon prices on the firm-level decision of what type of generation to build, and on whether to retrofit an existing plant or to replace it. Here we consider the effects of a carbon price on the CO_2 emissions of the existing fleet of generation plants. Since the replacement time for U.S. generation plants is very long (the median size-weighted age of the 1590 in-service coal generating units is 35 years), the short-run marginal carbon emission reductions are an important policy metric.

With a carbon price, electric generation units with significant carbon emissions, such as coal combustion facilities, will have increased marginal costs. In the short-run, demand for electricity can be met at the lowest cost by redispatching existing generation assets according to their marginal costs including the costs of their carbon emissions, taking into account transmission constraints. The resulting change in electricity price due to a price on carbon depends on the portfolio of generation facilities available for dispatch and the demand for electricity. Areas with significant amounts of low carbon generation, such as nuclear or natural gas, would see smaller increases in electricity prices, while areas that are predominantly supplied by coal generation facilities would see significant increases in short-run electricity prices.

An issue that has not been addressed is how electricity demand will be affected by a price on carbon. We examine the effects of a carbon price on electricity demand in the Midwest ISO, ERCOT and PJM. Existing generation in these control areas is redispatched under a range of carbon prices and the effect of a carbon price on load is investigated by analyzing a range of consumers' elasticities of demand in response to an increase in electricity price.

The Midwest ISO generation capacity is two-thirds coal. ERCOT's natural gas generators are two-thirds of its capacity, while PJM's capacity is roughly half coal, 30 percent natural gas, and 20 percent nuclear. None of the three has substantial hydroelectric generation. ERCOT has a small fraction of wind, but it is located far from load centers and there are known transmission issues [17].

II. METHOD

Because marginal costs for generators are private and are not available from the control area Independent System Operator (ISO), we use estimates for marginal costs as well as heat rates and fuel types from eGrid and regionally appropriate assumptions for fuel prices to calculate the unit dispatch.

Demand in each control area is met by economic dispatch, with the lowest cost generation used to meet the demand.

With a price on carbon, the marginal costs of the generator will change based on their carbon emissions. We use generator heat rates and CO2 emission factors from the US EPA eGRID database [18] to construct dispatch curves under a range of carbon prices. We assume that a single entity dispatches generation according to the lowest marginal costs, including the price of carbon dioxide emissions. The dispatch curves we construct are essentially short-run marginal cost curves for generation in each ISO. Thus, our curves do not incorporate the possibility of transmission congestion that could result in generating units being dispatched out of merit (least-cost) order.

Consumers see electricity prices that are higher than the economic dispatch-based wholesale price. We assume that consumers see real time pricing and that the price of electricity that an end user pays is the market clearing price plus a markup which varies depending on the customer class. The average electricity price by customer class for each region in

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the analysis and the average markup from wholesale price has been calculated. From these and from the total electricity sales, a weighted average markup for each control area is calculated, allowing the average retail price to be estimated from the economic dispatch. With a price on carbon, the price of electricity will increase and consumers will respond to this price increase by lowering their demand, according to their elasticity. The literature reports a range of elasticities [21, 22] and the actual elasticity is likely to vary among ISOs. Our elasticity calculations are based on the demand model estimated in [21]. Specifically, we assume an aggregate demand function with the following form:

$$(1) \qquad P(L) = \beta L^{1/\varepsilon}$$

$$(2) \qquad \beta = \frac{P_0}{L_0^{1/\varepsilon}}.$$

In equations (1) and (2), $P(L)$ is the demand function, L is the level of demand in the system, and ε is the price elasticity of demand. P_0 and L_0 represent price and demand under a "base case" where demand is completely unresponsive to price.

We do not assume any value for the elasticity of demand, but rather we examine the total reduction in carbon dioxide emissions in the Midwest ISO, ERCOT and PJM as a function of carbon price and elasticity. We use historical hourly load data for CY2006 in each of the three areas, and dispatch existing generation to meet the hourly load using economic dispatch under a range of carbon dioxide prices.

A. The Midwest ISO

Available generation capacity (the amount of the total installed capacity less units derated or down for repair that could be scheduled) and load data from 2006 for the Midwest ISO are shown in Figure 1 [24, 25].

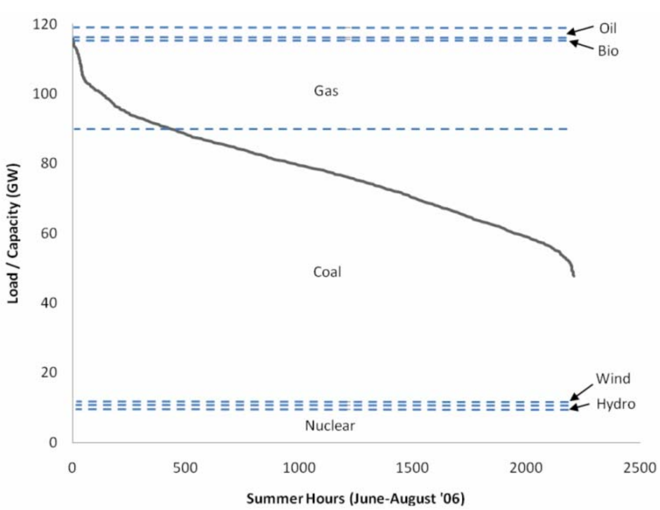

FIGURE 1: MIDWEST ISO SUMMER LOAD DURATION AND GENERATION CAPACITY [24,25]

Demand is met though economic dispatch [14]. The short-run retail marginal cost under a carbon price of \$50 per tonne and with no carbon price has been calculated.

The price of electricity increases with the price of carbon as generators must pay for their associated carbon emissions. We calculate the percent increase in retail electricity price (at each point in the load curve) and then use the range of short-run elasticities to find the new load.

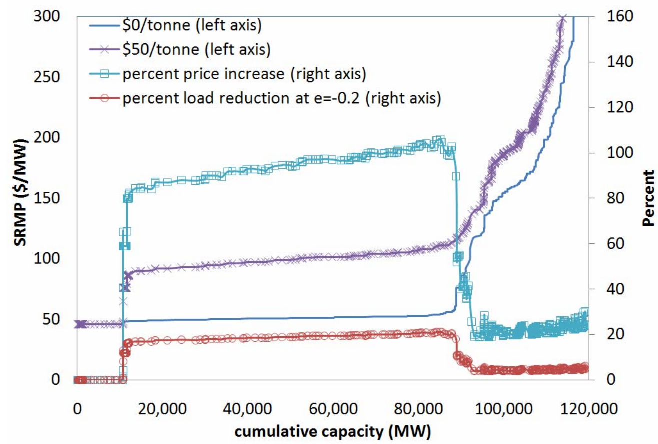

FIGURE 2: LOAD REDUCTION IN MIDWEST ISO WITH A CO_2 PRICE OF \$50/TONNE AND AN ELASTICITY OF -0.2

The increase in electricity price depends on the load (Figure 2). At very small loads, there is no change in price since low cost, carbon free (nuclear and hydro) generation in dispatched. The largest increases in price are at baseload, because there is a large amount of coal generation. At higher levels of demand (shoulder and peak) the increase in price decreases since generation with lower carbon emissions (natural gas) are dispatched. At a carbon dioxide price of \$50 per metric ton, the price of baseload electricity increases about 100 percent, while the price increase at peak demand is around 30 percent. Using an elasticity of -0.2, the baseload load decreases by about 20 percent and the peak load decreases by approximately 5 percent.

The percentage reduction in annual carbon dioxide emissions at a range of carbon prices and elasticities has been calculated. We emphasize that these are short-run marginal carbon dioxide reductions, reflecting redispatch of existing generation plants.

B. PJM and ERCOT

In this section, we repeat the carbon price and demand elasticity analysis for the PJM market and for ERCOT, the system operator in Texas. Like the Midwest ISO, PJM's generation mix includes a large amount of coal, particularly in the Western expansion of PJM's footprint. PJM, however, has a larger nuclear and natural gas base than the Midwest ISO. We have estimated the short-run marginal cost curve for PJM, with a carbon price of \$0/tonne and a carbon price of \$50/tonne. In the PJM system, the cost of electricity remains below \$100/MWh, even with a price on carbon, until dispatch reaches around 40,000 MW. In the Midwest ISO, \$100/MWh is reached at a level of demand less than 20,000 MW. Prices in ERCOT hit $100/MW at a level of demand around 10,000 MW with a price on carbon, even though the ERCOT system is less coal-intensive than either PJM or the Midwest ISO.

Our calculation of the short-run marginal price versus cumulative capacity reflects the dependence of ERCOT on natural gas generation and inefficient, highly-polluting coal plants. Costs in ERCOT are generally higher than in either PJM or the Midwest ISO. The possible carbon reduction in ERCOT, in percentage terms, is much lower than that achievable in either PJM or the Midwest ISO. This reflects the large amount of gas-fired generation in ERCOT compared to the other two systems discussed here.

III. Discussion

The short-run change in demand due to a carbon price, as well as the overall amount of carbon dioxide reduction depends on the specific ISO. Control areas with large amounts of carbon intensive generation, such as the Midwest ISO and PJM, can see large amounts of CO2 reductions since demand is reduced at high CO2 prices. Some illustrative results from our calculations are presented in Tables 1 and 2.

Table 1: Example comparison points across control areas, assuming price elasticity of demand of -0.1

Region	% CO_2 Reduction	CO_2 Price
MISO	5%	$20
	15%	$50
PJM	5%	$20
	15%	$50
ERCOT	5%	$50
	15%	Not Achievable

Table 2: Example comparison points across control areas, assuming price elasticity of demand of -0.4

Region	% CO_2 Reduction	CO_2 Price
MISO	15%	$20
	45%	$50
PJM	15%	$20
	45%	$50
ERCOT	15%	$50
	45%	Not Achievable

ISOs with a large amount of coal generation can see a large decrease in carbon dioxide emissions even with a modest CO2 price.

Control areas with a large percentage of natural gas or other low carbon generation such as ERCOT will see relatively small short-run decreases in carbon dioxide emissions even at high CO2 prices and large elasticities. This is because there is generally no other lower carbon generator to dispatch ahead of the natural gas that is currently being dispatched.

We assume that the price of natural gas remains unchanged in the short-run. With a price on carbon dioxide, the price of natural gas is likely to increase, as it becomes profitable for existing idle natural gas generators to be brought online, driving up demand for natural gas.

Although we analyze elasticity at a range of values, we assume that the elasticity is constant and is identical for all consumers in the system. We assume that consumers see real time pricing, that there is an infinite transmission grid and that a single entity dispatches generation based on marginal costs, and these marginal costs are passed directly on to consumers.

IV. Conclusion

We have estimated the short-run carbon-reduction impacts of a policy where carbon emissions from electric power plants are taxed or otherwise priced, and where all consumers see and can respond to real-time market prices that reflect the cost of generation. Our analysis covers three regional transmission organizations in the U.S.: PJM, ERCOT and the Midwest ISO. In PJM and the Midwest ISO, short-term carbon reductions on the order of 40% to 50% are possible, but would require a higher carbon price, and a level of short-run demand responsiveness higher than what normally appears in the literature. Even with these optimistic carbon prices and elasticities, carbon reductions in coal-intensive electric systems do not reach levels required to stabilize atmospheric carbon. We conclude that short-run measures are insufficient to obtain the magnitude of carbon reductions seen as necessary by climate scientists. Carbon policy in the U.S. is thus a long-run problem, and needs to explicitly cover investments in future electricity structure. Taxes and prices cannot do it all.

V. Acknowledgments

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