Climate Policy Risk to Generation Value in a Competitive Market

By Victor Niemeyer*

Introduction

In the near term—through the year 2015 and, possibly, even beyond 2020—new efficient coal-fired generation investment is generally insulated from the effects of CO_2 policy, but less efficient coal-fired units, potential candidates for environmental retrofits to meet evolving restrictions on SO_2 and NO_X emissions, face greater exposure. These results are due to both the currently high level of natural gas prices and the lack of significant quantities of natural gas-fired generating capacity in the existing (and pending) mix that could be used to displace coal-based CO_2 emissions. The analysis also demonstrates the high sensitivity of generator net revenue to fluctuations in natural gas prices. Compared to likely near-term climate policy, a large and sustained reduction in natural gas prices poses a much greater risk to the cash flows of all base load generation assets, even gas-fired plants in some cases.

Analysis Approach

Either with emission trading or a tax, the result will be that CO_2 emissions will have a price, and putting a value on CO_2 can greatly increase the operating costs of fossil-fired generation. The increase will depend on the generation plant's fuel and its efficiency (i.e., heat rate). For a coal-fired power plant, a \$1/ton value on CO_2 emissions will increase dispatch costs by approximately \$1/MWh. For a gas-fired combined cycle generating unit, a \$1/ton CO_2 value will increase dispatch costs by \$0.40/MWh, while a less efficient gas-fired combustion turbine or gas boiler will see its dispatch costs rise by \$0.60/MWh. These are typical values for power plants with no controls on CO_2 emissions. Higher efficiency units with lower heat rates will have correspondingly lower emission rates and vice versa. Hydro, nuclear, and wind generation have no incremental CO_2 emissions per MWh of generation.

Although placing a value on CO_2 raises the dispatch cost of gas-fired and coal-fired generation significantly, that is not the whole story. These higher dispatch costs will lead to higher bids into the power market and result in higher prices for wholesale power. From a cash flow perspective, what matters to generators is the increase in market prices vis-à-vis the increase in dispatch costs for these units. The net revenues to any individual generating unit will depend on the net balance of the cost impacts for its own operation against the revenue impacts from the higher market prices.

A schematic of the process for setting market prices and net revenues is presented in Figure 1. The figure shows three types of generation under two different CO_2 values. On the left side of the figure CO_2 has a value of zero, which means the highest cost generation needed to meet load is natural gas at a market price of \$50/MWh. The dispatch cost for nuclear in this example is \$5/MWh and its net revenues are the difference, \$45, given the price set by gas. The dispatch costs of coal in this example are \$25/MWh, and the net revenues are the difference (\$25). On the right-half of the figure, a value of \$20 on CO_2 raises the cost of both coal generation and natural gas generation, but the impact on coal generation's dispatch cost is greater. The market price set by gas rises from \$50 to \$60, allowing the net revenues for nuclear to increase by \$10, since the value of CO_2 does not affect nuclear costs. The dispatch costs for coal, on the other hand, increase by \$20, reflecting the increased value of CO_2. If market prices didn't change, its net revenues would be \$20 lower because of the greater emissions cost; however, because market prices go up by \$10, the overall effect of the \$20/ton CO_2 price on its net revenues is a decline from \$25 to \$15. Since natural gas operates at the margin in both cases, the net revenues for the natural gas generation remain at zero.

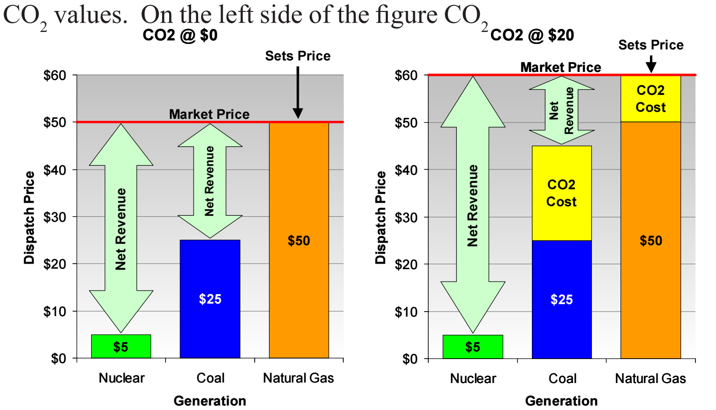

Figure 1
How a Value on CO_2 Affects Power Market Price and Net Revenues

While the simple example in Figure 1 illustrates the process, any power market will have a large number of generating units of varying efficiencies and fuel types. The units will also have operating cost differences associated

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See footnotes at end of text.

with design and age-related maintenance requirements and delivery costs for fuel. These differences are captured in the regional supply stack, shown in Figure 2, which presents the full distribution of generation costs in a market.

The generation supply stack provides a good representation of the competitive environment for generating units in a region. Specifically, it shows the units ranked in order of increasing dispatch costs by cumulative MW capacity. Marginal dispatch cost includes incremental costs for fuel, variable O&M, and environmental emission charges per MWh. Nuclear and renewables, such as hydro and wind, have the lowest marginal costs and are lowest on the stack, at the far left. Coal units, which have higher operating costs, come next and represent the largest single part of the stack in this example. Natural gas and oil generation have much higher costs and represent the rising portion of the stack on the right.

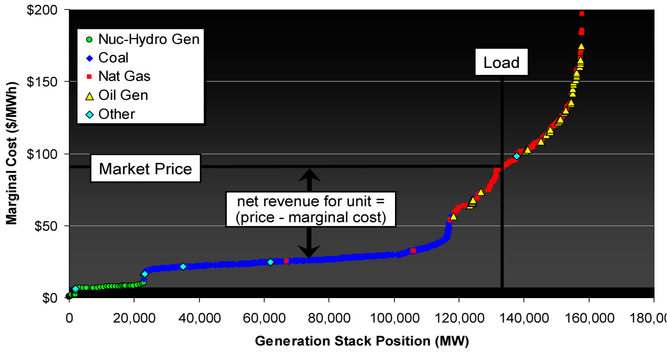

Figure 2
The Intersection of Load and the Supply Stack Sets Market Price

The market price at each hour in the year is determined by the point where system load (the MW of electricity demand for that hour) intersects the supply stack. Units to the left of that intersection will operate while the generating unit at the point of intersection is said to be on the margin and its dispatch cost determines the market price for all the generating units that are operating that hour. The units to the right do not operate. As the load varies over 8,760 hours of the year, the point of intersection with the supply stack changes, as does the market price.

All the units that are operating will receive the market price set by the marginal unit. Their dispatch costs will be less than the market price, and the difference will be their net revenue (i.e., price minus marginal cost).

For units that are low in a stack, which have the lowest dispatch costs, net revenues can be substantial. Over the year they will dispatch a large number hours, in many cases all of the hours of the year they are available; and when they operate, the margin between their costs and market prices will be the highest of any of the units in the stack. For units that are higher up in the stack, however, the net revenues over the year will be substantially less. There will be many hours when these units do not operate at all, and when they do operate, the market prices will not substantially exceed their own costs, leading to small net revenues over the year.

To understand how CO_2 policy would affect generating assets, we examine the effects across two regional markets – "Coal Land" and "Gas Land." These two power markets have contrasting generation mixes. Coal Land is represented by the NERC regions of ECAR-MAIN, while Gas Land is ERCOT.

In 2005, Coal Land had 22% of U.S. generating capacity but produced over 30% of electric power sector CO_2 emissions. Coal-fired generating units were on the margin about two-thirds of the time, while natural gas generation was on the margin the remaining third. The average price of wholesale power was approximately $53/MWh ($60 on peak, and $33 off peak). The generation stack for Coal Land was presented in Figure 2 above.

The analysis simulated the effect of CO_2 prices and natural gas prices on the existing generation fleets for these regions as of 2005. The operations in the simulations were calibrated to the market prices observed in that same year.

The Impact of CO_2 Price on Net Revenue

The effect of climate policy in Coal Land is modeled over a wide range of CO_2 prices. Five prototypical generating units, representing a range of positions in the generating stack, help us show the effects of climate policy. These units correspond to 10, 25, 50, 75, and 90 percentile points on the generation stack, as shown in Figure 3. The unit at the low cost end of the stack is designated as Uran/NU/11.1 (fuel is uranium, prime mover is nuclear, and heat rate is 11.1 MMBtu/MWh), followed by three coal plants—Coal/ST/9.8 (coal steam plant with a 9.8 MMBtu/MWh heat rate), Coal/ST/9.6, and Coal/

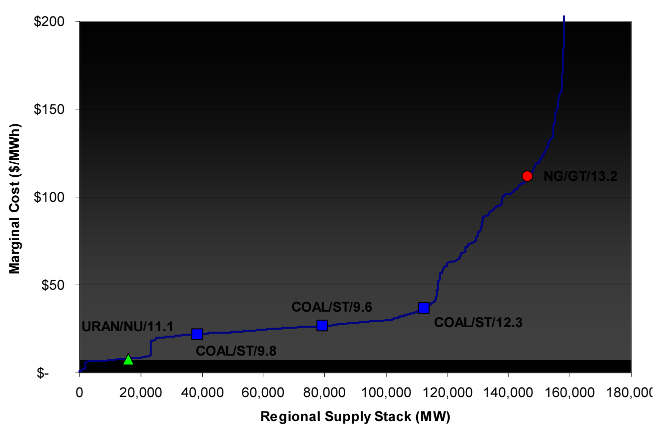

Figure 3
Five Prototypical Generating Units Used to Track CO_2 Policy Impacts

ST/12.3—and, lastly, NG/GT/13.2 (natural gas fired gas turbine with a 13.2 MMBtu/MWh heat rate).[1]

Figure 4 shows the effect on net revenues of placing a value on CO_2 emissions of zero to $50/ton for these five prototypical generating units. It shows the dramatic increase in net revenues for the non-emitting nuclear generating unit, which double at a CO_2 value of $50/ton. The revenues to the two efficient coal units (Coal/ST/9.8 and Coal/ST/9.6) decline only marginally, even at a value of CO_2 of $50/ton that increases their dispatch costs by almost $50/MWh. High CO_2 values do not reduce their annual dispatch hours and most of their higher costs are recovered in higher power market prices.

In contrast, the low-efficiency, high heat rate coal unit sees its net revenue drop by two-thirds. Its dispatch cost is rising more than 20% faster per dollar of CO_2 value than the costs of the efficient units so it runs fewer hours and earns lower net revenues for the hours it runs. The potential returns to retrofit investments for units with high heat rates are highly sensitive to a value on CO_2.

The remarkable stability of net revenues for the coal plants is due to the rapid increase in power prices. For every dollar rise in CO_2 value, average power prices rise by about $0.85/MWh. Peak prices—mostly fueled with gas on the margin—do not rise quite as much as off-peak prices when coal is predominantly the marginal fuel source.

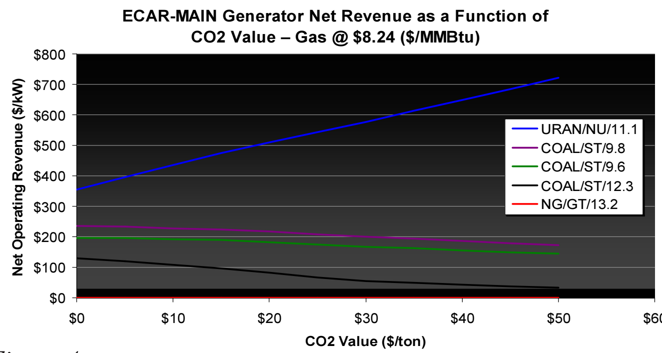

Figure 4
Impact of CO_2 Value on Generator Net Revenues for Coal Land

Given the volatility of natural gas markets, we explored the impact of different gas prices on net revenues for the five prototypical generating units. The results are presented in Figure 5 for a wide range of natural gas prices. The sloped lines show that the net revenues for the nuclear and coal units in Coal Land are highly sensitive to the price of natural gas. As gas is on the margin approximately a third of the hours, the price of gas will directly impact the price of power and net revenues for that fraction of time. The high volatility of gas prices thus creates a high level of uncertainty in net revenues.

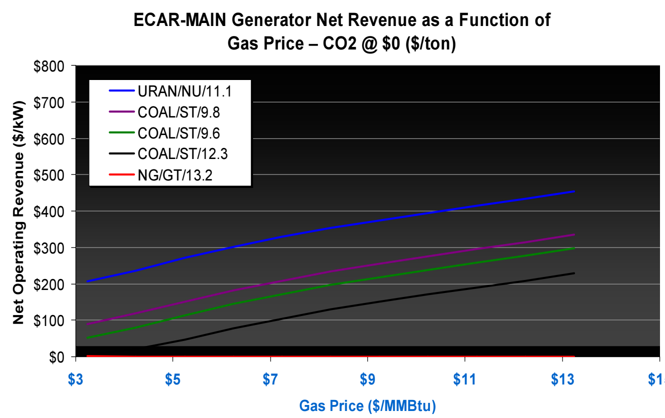

Figure 5
Sensitivity of Net Revenues to Natural Gas Price for Coal Land

Sensitivity Analysis

To get a sense of the importance of regional differences we applied the same analysis to a different region, Gas Land (represented by the ERCOT NERC region), which has about half the generation of Coal Land, and emits a quarter of the CO_2. Gas-fired generating units were on the margin in Gas Land approximately two-thirds of the time in 2005, while coal-fired generating units were on the margin the remaining third. Given the higher cost of gas, the average price of wholesale power is more than a third higher than in Coal Land – $74/MWh ($82 on peak and $49 off peak) versus an average price of $53/MWh in Coal Land.

The analysis compared net revenue sensitivity to CO_2 value for identical hypothetical generating units that we placed in each region. The units have a heat rate of 9 MMBtu/MWh, and pay the average delivered cost of coal in their respective regions. The plots of net revenues versus CO_2 value are presented in Figure 6. They show a much higher cash flow to coal generation in Gas Land, but also greater sensitivity to CO_2 value.

The comparison in Figure 6 is based on the average price of natural gas observed in 2005, $8.24/MMBtu. The figure below shows the sensitivity of these net revenues to this assumption. Figure 7 repeats the above figure (on the left) and places it next to the same plot of net revenue based on a price of natural gas that is $4 lower. While the plot on the left at $8.24 gas shows high net revenues, the plot on the right with $4.24 gas shows net revenues well below finan-

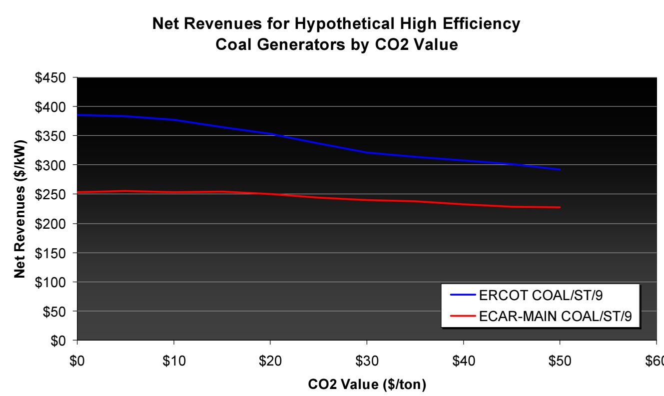

Figure 6
Comparison of Net Revenues for a Highly-Efficient Coal-Fired Plant in Coal Land and Gas Land

cial viability thresholds for both regions.

For the Coal Land location, the effect on net revenues from CO_2 value is small, but the sensitivity to natural gas price is dramatic. For the Gas Land location, net revenues for the efficient coal plant drop markedly with increased CO_2 value, but the effect of lower natural gas prices is even greater. Clearly, the cash flows for these units are much more sensitive to the price of natural gas than to CO_2 value.

It is important to be clear that the plots and analyses presented above are from simulations of the regional generation existing in 2005. By the time any climate policy comes into effect the generation mixes will have had time to change. However, the trends in additions are increasing coal generation, with some gas, and modest additions of renewables (compared to the total capacity now existing). This means that generation mixes will be if anything more coal intensive by the time a policy became effective. As a consequence, coal generation will not face be competing with more non-emitting nuclear or hydro generation. Given the long lead times this will remain the case for many years. However, a price on CO_2 provides a very strong incentive to investors to add new generation that is non-emitting. As this new capacity comes online it will go to the top of the dispatch order and start to displace fossil generation. How soon Coal Land or Gas Land will see 20GW of new nuclear generation, or new coal with CO_2 capture and storage, is a matter of conjecture, but beyond 2020 seems reasonable at this point.

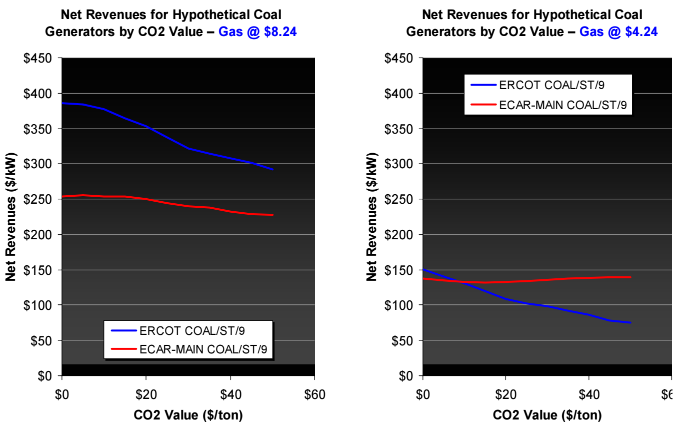

Figure 7
Comparative Sensitivity of Net Revenues to Natural Gas Prices and CO_2 Value by Region

Conclusions

From a methodological perspective, this analysis shows the importance of considering the power market impacts of climate policy, rather than just the impact of rising CO_2 value on production costs. It is clear that higher production costs resulting from CO_2 value do not necessarily imply lower net revenues, due to the important role played by plant costs throughout the generation stack in determining wholesale power market prices.

The exposure of coal generation to climate policy is highly dependent on the regional generation mix and the level of natural gas prices. Regions with little gas generating capacity have few opportunities for gas to displace coal. In addition, high gas prices make it very expensive for gas generation to do so as well. Under these circumstances, a value on CO_2 emissions does little to affect the dispatch and CO_2 emissions, and the higher costs due to a CO_2 policy are passed on to the wholesale market. Only under the combined circumstances of available gas-fired generation capacity and low gas prices does a value on CO_2 significantly impact the net cash flows of efficient coal plants. However, low gas prices alone are sufficient to reduce the net revenues for new coal generation well below the net revenues needed to stimulate investment.

The impact of CO_2 value on wholesale electricity prices is quite dramatic. In Gas Land, the price of electricity rises $0.70 for each dollar of CO_2 value; while in Coal Land, the increase is $0.85 on the dollar. In time, these wholesale price increases will be transmitted to retail customers.

Footnote

[1] Note that the lowest cost coal unit, Coal/ST/9.8, does not have the lowest heat rate, but its low delivered fuel cost causes it to be dispatched before the more efficient Coal/ST/9.6 unit.