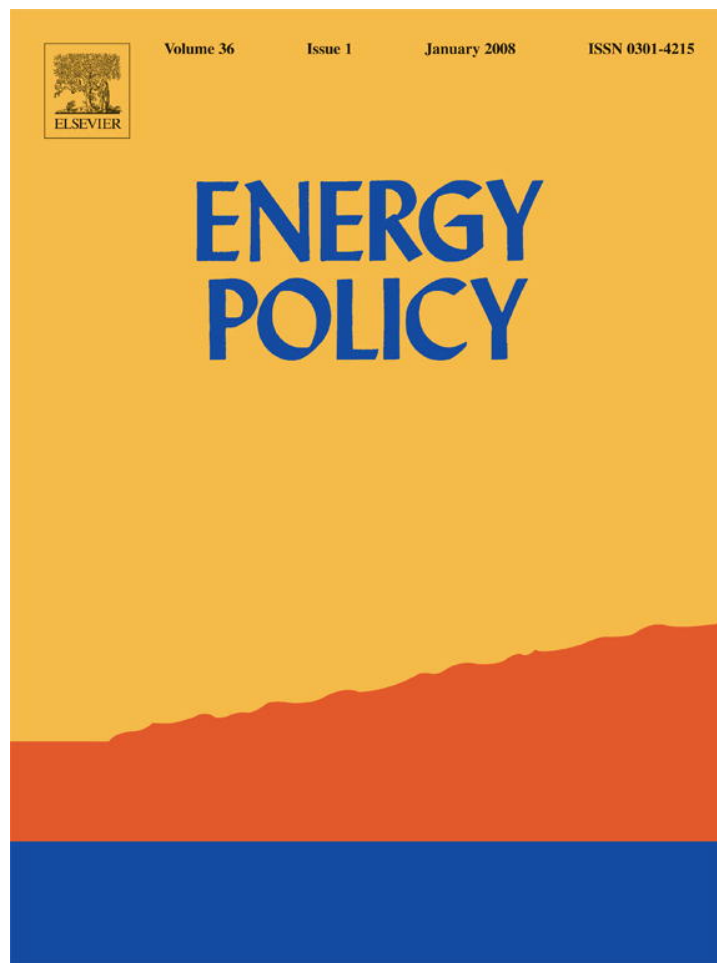


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Simulation scenarios for rapid reduction in carbon dioxide emissions in the western electricity system

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Abstract

This paper describes a computer simulation analysis of carbon dioxide emissions in the electric power system in the western United States. Legislation at both the state and federal level would impose a price on emissions via cap-and-trade in allowances for carbon dioxide emissions. The simulation scenarios for the western system indicate that dramatic reductions in emissions are possible with generating technologies that exist today. Wind and biomass generators play a key role even with conservative assumptions about their future costs. In contrast, generation from advanced technologies provide only a minor contribution by the year 2025. These scenarios provide support to those who argue that the US should move expeditiously to put a price on carbon dioxide emissions.

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Keywords: Carbon emissions; Electricity policy; Simulation modeling

1. Introduction

The accumulation of greenhouse gas (GHG) emissions in the atmosphere is arguably the most serious environmental threat of our time.¹ Carbon dioxide (CO₂) emissions are the

Abbreviations: AB32, Assembly Bill 32 in California, the Global Warming Solutions Act; CC, combined cycle power plant (fueled by natural gas); CO₂, carbon dioxide, a greenhouse gas; C, carbon, the C in CO₂, there are 3.67 pounds of CO₂ for each pound of C; CEC, California Energy Commission; CPUC, California Public Utilities Commission; EIA, Energy Information Administration; GHG, greenhouse gas; IOU, investor owned utility; S139, Senate Bill 139, the Climate Stewardship Act of 2003; WECC, Western Electricity Coordinating Council; WSU, Washington State University; aGW, average GW, the energy from 1 GW operating for all hours in a year; BTU, British Thermal Unit, a measure of energy; GW, Gigawatt, a measure of capacity; a GW is 1000 MW; KW, kilowatt, a measure of capacity; a kW is 1000 W; kWh, kilowatt-hour, a measure of electric energy; MMTC, million metric tons of C emissions, equivalent; MMTCO₂, million metric tons of CO₂ emissions, equivalent; MTCO₂, metric ton of CO₂ emissions; MW, Megawatt, a measure of capacity; a MW is 1000 Kw; MT, metric ton, which is 1000 kg or 2205 pounds or 1.1 short tons; MWh, Megawatt-hour, a measure of electric energy; \$/MWh, \$ per MWh to measure electricity prices (the same as mills/kWh)

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¹The problem of global warming is described in the reports of the Intergovernmental Panel on Climate Change (IPCC, 2001a–c, 2007) and in popular books on climate change by Schneider (1990), Flannery (2005) and Gore (2006).

largest GHG, accounting for over 80% of the emissions in the US (EIA 2003, p. 35). CO₂ emissions arise from the combustion of carbon fuels such as gasoline in vehicles and coal in power plants. Energy-related carbon emissions are a global problem, and the US produces more emissions than any other country, accounting for 24% of the world's energy-related emissions (EIA, 2003, p. 36). This paper explains that the electricity sector is likely to play a pivotal role in reducing CO₂ emissions. There are many ways to generate electricity, and this flexibility gives the electricity sector a major advantage in responding to changes in market incentives to encourage carbon-free technologies. The responsiveness of the power sector is the focus of this paper.

Fig. 1 summarizes some of the targets for emission reductions that have been adopted or proposed around the world. Emissions have been growing at around 1.4%/year. The upward curve shows the future emissions if this trend continues: emissions would double by the year 2040 and double again by 2090. Fig. 1 shows large differences in the stringency of the targets. Some call for holding emissions constant; others call for dramatic reductions over time. Some targets apply to the next two decades; many extend to the year 2050; and some extend to the year 2100. However, when compared to the upward trend, all targets require major reductions in emissions.

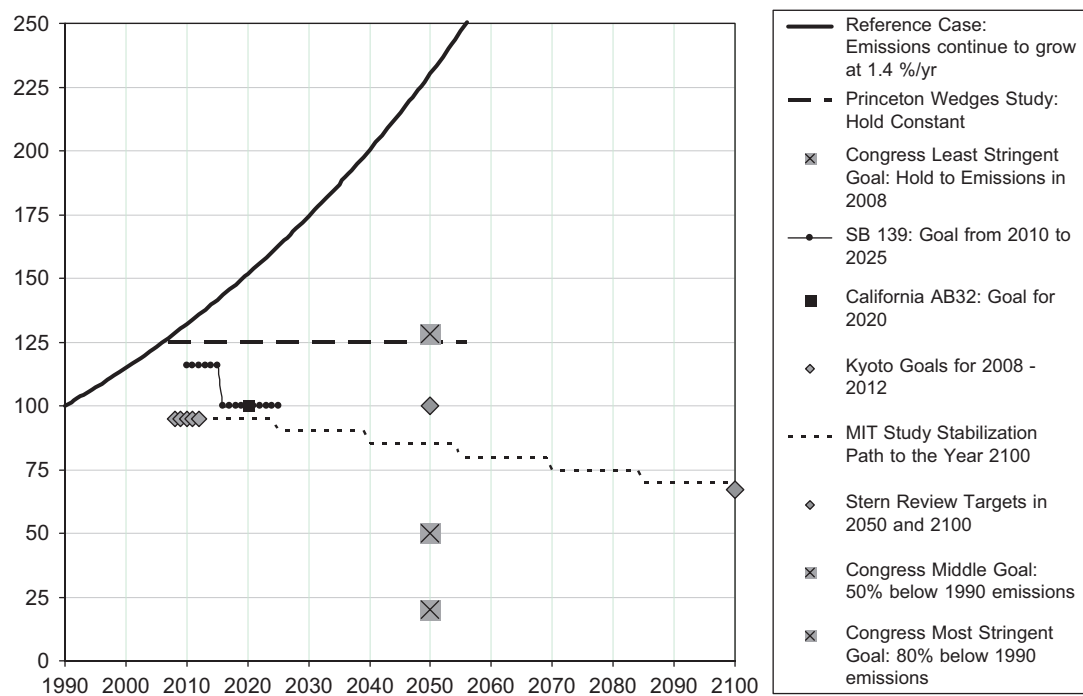


Fig. 1. Comparison of goals for emission reductions. (Fig. 1 is adapted from a similar comparison in “Global Climate Change and the Electric Power Industry” in the forthcoming volume on Competitive Electricity Markets by Sioshansi (2008). This paper draws on several segments of the chapter. For ease of comparison, 100 denotes the emissions in the year 1990.)

The targets from the Kyoto treaty are probably the best known. The treaty became effective in February of 2005 and called for the Annex I countries to reduce emissions by 5% below 1990 emissions by the year 2008 and to maintain this limit through 2012. The Kyoto Protocol allows for a range of emission reductions (i.e., some countries will aim for reductions greater than 5%), and it allows countries to purchase reductions achieved elsewhere (i.e., through a clean development mechanism, CDM). The extension of the Kyoto Protocol beyond 2012 is the subject of ongoing discussions. The Princeton study is also widely known. Their research team asked what would be required to halt the upward growth in emissions, with the ultimate goal of stabilizing atmospheric CO₂ at around 500 ppm. They argued that this requires annual emissions to be held constant at 7 gigatons of carbon (GTC) beginning in 2004. The Princeton study described the difference between the constant emissions and the upward trend as a “stabilization triangle” comprised of seven “wedges.” Each wedge depicts carbon reductions of 1 GTC per year by 2054. The study then described the changes that could deliver the needed reductions.

The solid line from 2010 to 2100 represents the stabilization path in an MIT study reported by Webster et al. (2003). The limit on emissions was imposed in modeling calculations designed to stabilize atmospheric CO₂ at 550 ppmv or lower. The scenario assumed that the Kyoto emissions caps are adopted by all countries by 2010, and the caps would be extended and further lowered by 5% every 15 years. By the end of the century, the emissions would be 35% below the value in 1990. The 2100 target in the MIT study matches the corresponding target

from the *Stern Review*. The *Stern Review* shows a variety of emission paths associated with stabilizing atmospheric GHG at 550 ppmv of CO₂ equivalent (CO₂e). Fig. 1 shows 2050 and 2100 targets that are representative of the various paths.

There are several new proposals under consideration in the US Congress (NRDC, 2006). Some apply only to the electricity sector, but most apply to multiple sectors. They all call for cap-and-trade in carbon allowances,² but the proposals differ widely in the stringency of the cap. The impacts of these proposals were the subject of a recent analysis by MIT (2007). Fig. 1 shows three targets used by the MIT researchers to span the range of bills under debate in the US congress:

- 2008 emissions: The least stringent of the targets calls for emissions at or below emissions in the year 2008.

²Most policy makers argue that incentives are needed in order to put a price on carbon, but the price could be implemented with either a carbon tax or a carbon market. The carbon tax specifies the cost of carbon emissions, and the reduction in emissions is uncertain. The carbon market specifies the cap on emissions and the price of allowances is uncertain. If the costs of emission reductions could be estimated with certainty, both policies could be designed to deliver the same reduction in emissions. However, there is great uncertainty in costs, so it is important to discuss the relative merits of a tax or a market. Generally speaking, the tax is considered to deliver a more reliable cost of emissions, and the actual emissions are uncertain. The carbon market is based on a legislated cap on emissions, so there is more emphasis on reducing emissions. The price that emerges from cap-and-trade could be highly volatile. The choice between a tax and a market is discussed by Pizer (1999), Jacoby and Ellerman (2004) and Ford (2008). Most economists argue for the carbon tax, but the current political factors tend to favor the adoption of carbon markets.

This case is similar to the Bingaman-Specter Draft 2007 proposal and the Udall-Petri 2006 bill.

- 50% reduction: The middle case in the MIT study calls for emissions to be reduced to 50% below the value in 1990. It corresponds approximately to the Feinstein 2006 bill.
- 80% reduction: The most stringent target calls for emissions to be reduced to 80% below the value in 1990. This case corresponds approximately to the Sanders-Boxer 2007 bill.

The MIT researchers estimated carbon prices over the interval from 2015 to 2050 based on a core set of assumptions which include the option to bank allowances for future use. For the middle case, prices are expected to reach nearly 50\$/MTCO₂ by 2020 and 60\$/MTCO₂ by 2025. These prices correspond closely to prices used in the scenarios described later in this paper.

2. California's recent carbon policies

California is moving expeditiously on carbon legislation with two important initiatives adopted in 2006. In February of 2006, the California Public Utilities Commission (CPUC) announced that it would develop a cap on GHG emissions for the state's Investor Owned Utilities (IOUs). The CPUC (2006) explained that it will create a "load-based cap that encompasses all of the GHG emissions produced in the course of generating electricity to serve utility customers. Imported energy and power produced within California will be treated equally under this system." The CPUC (2007) has also proposed rules which would prohibit the IOUs from purchasing out-of-state generation that exceeds a carbon emissions standard.³

In September of 2006, the Governor signed Assembly Bill 32, the Global Warming Solutions Act of 2006. It limits California's GHG emissions to 1990 levels by the year 2020. AB32 would apply to all emissions, not just the emissions from the electricity sector. AB32 sets the goal, but it leaves many important decisions about regulatory and market-based mechanisms to be made later by either the state Environmental Protection Agency or the state California Air Resources Board (CARB). Detailed recommendations are provided by the market advisory committee of the CARB (2007).

³The standard calls for CO₂ emissions no greater than the emissions from a combined cycle gas turbine plant (1100 pounds of CO₂ per MWH). This rule effectively prohibits investment in new conventional coal-fired power plants to serve base loads in California. The CPUC views the standard as a "near-term bridge" until an enforceable load-based GHG emissions limit is established and in operation. Washington has adopted the same standard for long-term contracts for base load generation, and it called for the state to cut emissions to 50% below 1990 levels by 2050. A somewhat similar standard has been proposed at the national level in the Clean Coal Act by Sen. Kerry. It would ban construction of new coal-fired power plants that do not have technology for carbon capture and sequestration.

Fig. 1 puts the AB32 target in perspective. The goal for 2020 is to limit California's emissions to no greater than the emissions in 1990. This target happens to be the same as the goal set by The Climate Stewardship Act of 2003. The Act was the subject of detailed studies which provide important insight on the responsiveness of the energy sector to carbon prices. S139 has been studied much more carefully than the other proposals, and the findings from the key study are summarized below.

3. The Climate Stewardship act

In January of 2003, Senators McCain and Lieberman introduced Senate Bill 139 (S139) which called for a cap and trade system for GHG. The phase I cap on GHG emissions was set at the value from the year 2000. After 2016, a phase II cap would limit GHG emissions to the value from the year 1990. The Act was the subject of detailed studies by Paltsev et al. (2003) and by the US Energy Information Administration (EIA 2003). The EIA analysis is especially relevant to this paper because of the detailed portrayal of the energy system. Fig. 2 summarizes the key findings from the EIA analysis of the electric power sector.

Emissions from the power sector are shown in million metric tons of carbon equivalent (MMTC). There were 621 MMTC in the year 2000. By 2025, electricity sector emissions would be 40% higher. The cost of carbon allowances is shown in \$/MTCO₂. The EIA used repeated simulations to search for an allowance price trajectory that would induce the entire economy to achieve the goals. Their search led to a price somewhat above 20\$/MTCO₂ when the market would open in 2010. The price would then rise to 60\$/MTCO₂ over the next 15 years. These prices were estimated to be sufficiently high for emissions from all sectors to meet the goals of S139.

Fig. 2 shows that the electricity sector emissions would decline well below the allowances available to the power sector. This means the power sector would have extra allowances that could be banked for future use or sold to less responsive sectors in the economy. The electricity sector was estimated to achieve a 76% reduction in carbon emissions by the year 2025. This could be achieved with a 46% increase in the average retail electricity rate charged in the year 2025.

These impacts are displayed in Fig. 3 with the graph divided into diagonal halves by a "50/50 line." The line helps us see which sectors would be most responsive to carbon prices.⁴ For example, the transportation, industrial and residential sectors fall well below the line. They would achieve little reduction in emissions and would end up

⁴The idea behind cap-and-trade is that market forces will bring forth a strong response from those sectors with the greatest flexibility in response. Less flexible sectors would then buy the needed allowances from the more responsive sectors. This reasoning applies to a carbon tax as well as a carbon market provided the tax is set to follow the upward trajectory that would achieve the necessary emissions reduction.

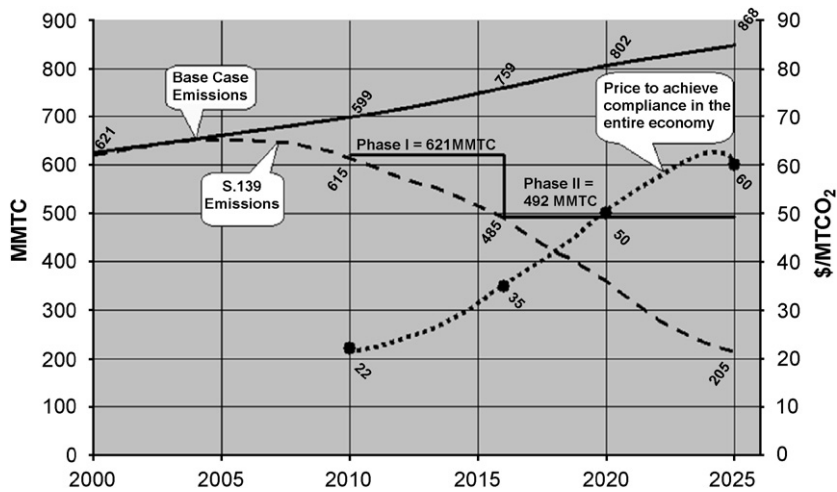


Fig. 2. Summary of the EIA analysis of the nation's electricity sector response to carbon prices.

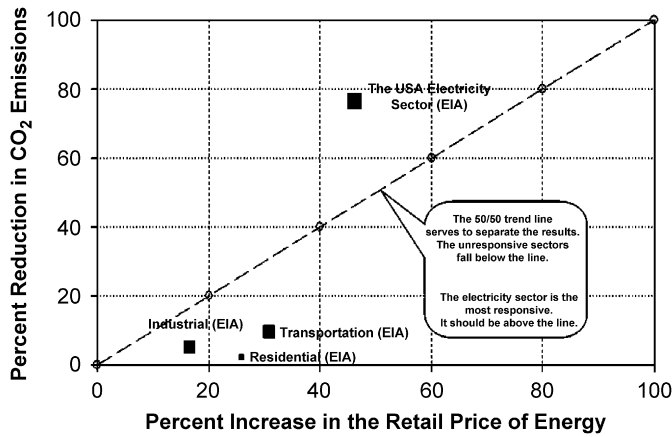


Fig. 3. EIA estimates of the impact of the Climate Stewardship Act.

buying allowances from the more responsive sectors. The electricity sector is located well above the 50/50 line. It is expected to lead the way in reducing emissions. The EIA estimated that the retail rate impacts in the power sector tend to be substantially higher than in the other sectors of the economy.⁵

Fig. 4 shows the changes within the electricity sector that makes the 76% reduction in emissions possible. The horizontal axis is measured in billions of kWh/year of change in generation. The four black bars at the bottom of the bar chart show the reduction in fossil-fueled generation caused by the carbon prices in S139. The dominant response is clearly the large reduction in conventional

coal-fired generation. The remaining bars show the estimated changes to compensate for the reductions in the conventional, fossil-fueled power stations. For example, a compensating response is the demand response to the higher retail prices. The EIA estimates that demand would be reduced by nearly 600 billion kWh/year by the year 2025, an 11% decline compared to the reference case.

The increased response from renewable generators (biomass, wind and geothermal) is shown next. The EIA expected generation from biomass-fueled plants to be the most responsive of the renewable technologies, providing an extra 400 billion kWh/year by 2025. Wind generation is projected to provide 0.6% of total generation in the reference case and 6% in the S139 case.

The top three bars draw attention to the advanced technologies that require further research, development and/or policy changes to ensure their response. The most responsive of these technologies are expected to be new gas-fueled combined cycle (CC) plants with carbon capture and sequestration equipment. The EIA cautions that any of the advanced technologies could emerge, depending on relative prices of coal and gas and the progress in research and development. With the EIA assumptions, gas-fueled CCs are the dominant use of sequestration technologies. However, new coal plants with carbon capture and sequestration are also projected to provide additional generation. And, according to the EIA, there would also be increased investment in new nuclear generating stations which would provide over 400 billion kWh/year of additional generation.

4. Advanced technologies and the timing of carbon incentives

An important question for current policymakers is the wisdom of initiating carbon markets if the electricity sector response depends on the increased generation from the advanced technologies shown at the top of Fig. 4. Carbon sequestration technology has great potential (IPCC, 2005),

⁵One reason for the relatively high retail impact is the extensive use of coal in power generation (around 50% for the US). Coal is the most carbon intensive fuel for power generation, and the cost of allowances drives up the variable cost of existing coal plants. Gas-fueled plants (which are frequently on the margin in the coastal regions) also face higher variable costs. Another factor contributing to the high retail impact in the power sector is that generation costs account for a relatively high portion of retail electricity prices to the consumer.

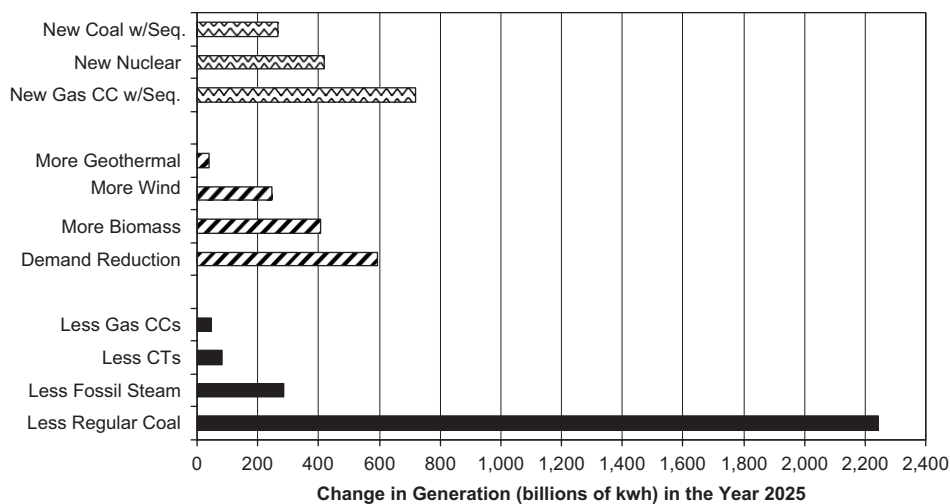


Fig. 4. Summary of the expected responses to carbon prices in the US electricity sector.

but it is not commercially available. Advanced nuclear technologies could provide an alternative source of carbon-free generation, but the industry currently faces stagnation and decline. If new nuclear plants are to provide significant additional generation, the industry must deal with the unresolved problems of high construction costs, waste disposal, proliferation, security and safety.⁶

Should the US should adopt carbon legislation or postpone action until the advanced carbon-free generating technologies become available? Perspective on this question is provided by a recent study (Ford, 2006) of the impact of carbon prices on the western power system.

5. Power sector response in the western US and Canada

Electricity generation in the western US and Canada is provided in a large, interconnected power system known as the WECC, the Western Electricity Co-ordination Council. The boundaries of the WECC and its four power areas are shown in Fig. 5. This region has considerably more hydro resources, and it makes less use of coal-fired generation than the nation as a whole. Gas-fueled CCs with carbon sequestration were selected as the most likely form of carbon sequestration, based on the EIA projections. With gas prices at \$5.50 per million BTUs, the investors in CCs with sequestration were assumed to face a total levelized cost of around 75\$/mWh (Ford, 2006). This technology was the only advanced, carbon-free technology, so it served as the “back-stop” technology in the modeling calculations. However, it would not become available until 2020, so the CCs with sequestration would provide only a small fraction of total generation.

⁶The challenges of the nuclear industry are not described here. Readers interested in this industry are referred to the MIT (Paltsev et al., 2003) report on *The Future of Nuclear Power*.



Fig. 5. Map of western states and provinces in the WECC.

The WECC study adopted the assumption that current efficiency programs would remain in effect.⁷ With a demand reduction limited to current programs, the key to the simulated response is the contribution from renewable generators such as biomass and wind. The west has huge wind resources (Ford, 2006), so it is important to put the EIA projections of wind generation in perspective. Fig. 6 compares the percent of generation from wind in the EIA study with wind generation in Europe. The EIA results are at the bottom of the chart. Wind is projected to provide 0.6% of US generation by the year 2025 in the reference case. With the high prices of carbon allowances, wind investors will have a strong advantage over their competitors, and the EIA estimates wind would provide 6% of the nation's electricity generation by the year 2025. This is a 10-fold increase, a seemingly dramatic response.

⁷The conservation-efficiency programs are limited to “current programs” (Ford, 2006). This assumption is adopted as a cautious outlook on the potential for these programs to lower the demand for electricity. Were utilities to adopt “best practices” for efficiency, CO₂ emissions would be reduced more rapidly than in the simulations shown in this paper. Also, there would also be less investment in renewable generation than shown here.

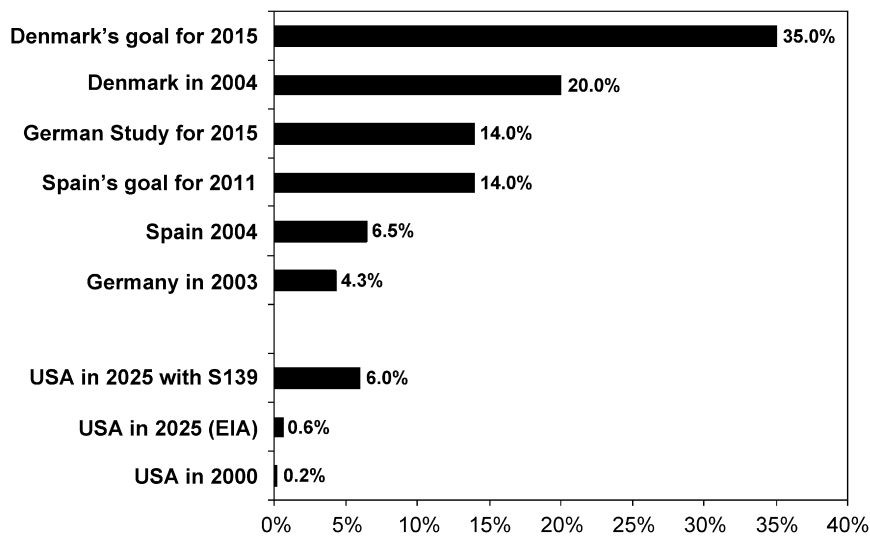


Fig. 6. Comparison of various projections of wind generation. Sources: The US estimates are from the EIA (2003). European values are explained by Ford (2006).

But the response is less dramatic when it is compared with wind generation in Europe. The top bars in Fig. 6 show current and planned wind generation in Europe. These reveal that the potential for wind generation is much higher than suggested by the projections in the EIA study. The key question is whether the carbon price incentive is sufficiently strong to allow wind investors to deal with the increasing costs of adding more and more wind to the western system.

The cost of expanding wind capacity was simulated in a conservative manner in the WECC study. We assumed there would be no reduction in wind costs as more capacity is constructed and operated over time. In other words, we ignored the cost reductions that one would expect from learning and R&D. We assumed that wind's costs would increase as more and more capacity was added to the system. Higher construction costs were incorporated as the simulated investors turned to less attractive sites. (The newer sites might be further removed from the transmission corridors or they might be located in lower class wind regions.) Higher costs were also attributed to the challenge of managing the growing amount of intermittent generation.

A conservative approach was also adopted for biomass-fueled generation. For biomass to be considered carbon neutral, the fuel should be part of a cycle of biomass growth, harvesting and consumption in the power plants. For the WECC study, biomass generation was based on fuel from dedicated crops (i.e., such as hybrid poplars). As with wind generation, we adopted the cautious position that there would be no costs reductions from the experience in growing and transportation of the fuel. Rather, we designed the simulations in the opposite direction. We assumed that investors would face higher and higher costs for harvesting and delivering biomass as more and more tree farms were located in the west. This assumption was based on the idea that tree farms would be located in more

difficult locations (poorer soil, need for irrigation, longer transportation distances to the power plant).

6. Simulation scenarios

The CO₂ emissions from generators in the WECC were estimated with a simulation model developed at Washington State University (WSU).⁸ The model was designed for simulation studies of a wide variety of scenarios. For example, natural gas prices may remain high, or they could return to values predicted by the EIA (2003). Load growth might remain at low values, or we could see a return to more rapid growth. The transmission system could remain at approximately current capacity, or there might be major expansions to link the coastal load centers with coal and wind resources in the eastern areas of the WECC. Two scenarios are described in this paper.

The simulations begin with conditions in the year 2005. The system is then simulated to the year 2025 to match the time horizon used in the EIA study.⁹ The first scenario described in this paper envisions 2.5% annual growth in electricity demand in all areas of the west. (This is a rapid rate of growth, at the high end of the range of recent forecasts.) The base-case simulation assumes that no new construction is initiated for several years because of the high reserves. Consequently, the thermal capacity declines somewhat due to retirements. We assume that new construction will be initiated around the year 2008, as this initiation causes planning reserve margins to fall gradually into alignment with the 15% goal often used in resource planning. Thermal capacity would grow starting around

⁸The WSU model is described in detail by Ford (2006); it employs a combination of system dynamics and engineering methods, as described by Dimitrovski (2005).

⁹The model operates with time in months with a typical 24-h day in each month of the year. The time graphs show years on the horizontal axis for ease of interpretation.

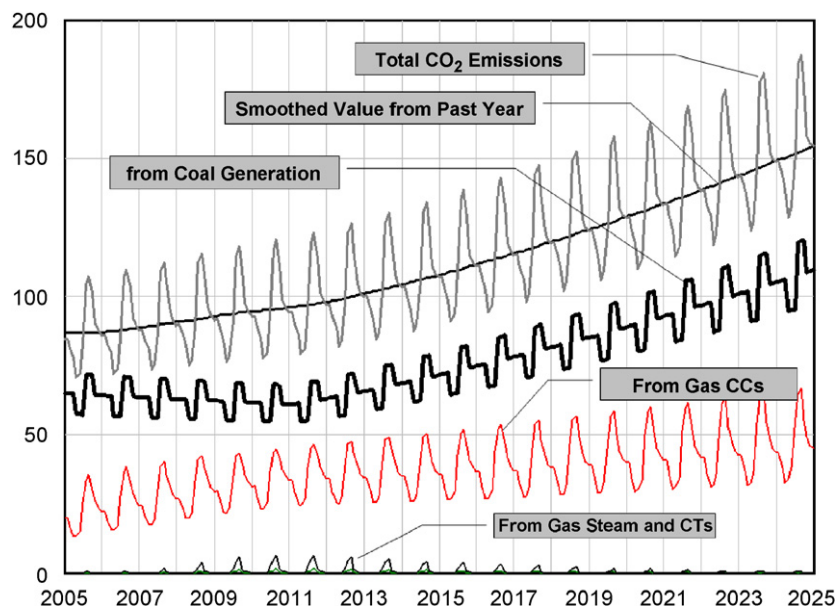


Fig. 7. CO₂ emissions (MMTC/year) in the first scenario.

the year 2010 and continue to grow for the remainder of the simulation based on the assumption that construction will keep pace with growth in demand and retirements.¹⁰ This scenario envisions natural gas prices at the values expected by the EIA in the S139 study, so gas-fired CC power plants will be favored by investors. We assume that the gas-fired plants are constructed mainly in the coastal areas, close to the load centers. This scenario provides a starting point. The goal is to learn if the western system can deliver the dramatic reduction in CO₂ emissions that were estimated by the EIA for the nation as a whole.¹¹ And we wished to learn if the reduction could be achieved with technologies that are available today.

¹⁰Recent experience in the west indicates that construction of new generating capacity can appear in waves of boom and bust (Ford, 2002). Our purpose here is to look at the implications of a carbon market in the western system. For this purpose, it is more useful to adopt the assumption that construction of new generating capacity will appear in a steady, timely manner as needed for the supply of electricity to keep pace with the growth of demand. The model uses the general goal of 15% reserve margins under “critical hydro” conditions. The simulations begin with reserves at twice the goal (McCullough, 2005), so construction could start in 2008 in the first scenario and in 2012 in the second scenario. The “keeping pace” assumption is an optimistic assumption about the ability of utility planners and regulators to shift power plant construction from a merchant investor gamble on future spot prices to a more dependable, planned process of “integrated resource planning.” According to a 2006 survey of electric utility executives, 85% “anticipate a resurgence of the concept of the traditional utility having an obligation to serve and to ensure resource adequacy” (Gale, 2006). If the distribution companies are to ensure resource adequacy, they must be willing to sign contracts with generators for long-term supply at prices that exceed the spot prices that may be available in the wholesale market. We assume that the distribution companies sign such contracts, and state regulators pass the “implicit capacity payment” associated with such contracts into retail rates.

¹¹Some readers may mistake the simulation as a forecast of the future of the WECC. The simulations are not meant as forecasts. Rather, they provide insight on the responsiveness of the western power system.

7. A scenario with rapid growth and construction dominated by gas CCs

Fig. 7 shows the CO₂ emissions over the 20-year simulation. The total emissions vary during the different seasons of each year, with peak values in the summer when there is less hydro generation and a much greater dependence on fossil fuels. Total, smoothed emissions grow from 87 MMTC in 2005 to 154 MMTC. The growth in carbon emissions is caused by a combination of increased emissions from coal plants and from gas-fired CCs. Emissions from gas steam plants and gas combustion turbines (CTs) appear in the summer months, but these are not a major contributor to total emissions.

Coal-fired generation accounts for the majority of the CO₂ emissions in the western system. By the end of the simulation, coal generation produces two-thirds of the total emissions. This result may seem surprising since new coal plants gain a relatively modest share of new construction. The large share of emissions is because coal is the most carbon intensive fuel for power generation. It is clear from Fig. 7 that coal generation must be reduced substantially if the WECC is to achieve dramatic reductions in CO₂ emissions.

Fig. 8 shows how the generating technologies would be dispatched during a typical August day in the final year of the simulation. This simulation is based on “average year” hydro generation, with user-specified monthly shape factors to allocate the hydro energy into separate months. Hourly shape factors are then used to represent the ability of operators to shape the generation toward the middle of the day. Other generation contributes a small, constant amount during the August day. Wind units are also operated as must-run. The base case simulation assumes that wind generation occurs evenly over the 24 h in the

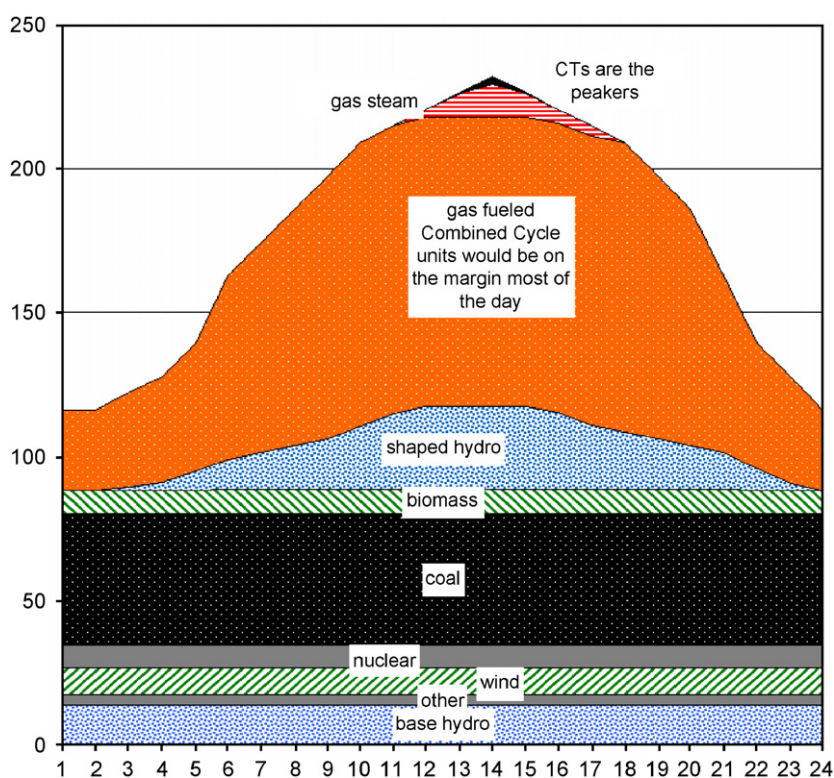


Fig. 8. Generation for a typical August day in the final year of the first scenario.

day.¹² The thermal units are “market run.” Their operation is controlled by the wholesale prices in each hour compared to the units’ variable costs. Fig. 8 shows that nuclear, coal and biomass units would operate for the entire summer day. The model retires around 20% of the nuclear capacity that exists at the start of the simulation.

Gas-fired CCs are the most popular choice for new investors in the first scenario. This generation comes from a combination of units existing in 2005 and the many new units that are constructed during the simulation. Some of the CCs would operate for the entire day; others would run for only 8 h in the day. The CCs are on the margin from 1 a.m. to 11 a.m. and again from 6 p.m. to midnight. During these hours, the wholesale market price will be set by the variable costs of operating the CCs in the west.

The more expensive gas-fueled generators are shown at the very top of the stack. Gas-fueled steam units operate for around 4 h in the day. These units’ variable costs range from around 60–90\$/MWH. We allow the user to specify a fraction of the gas-steam capacity as subject to “economic withholding,” but there is no withholding in the base case simulation. Gas-fueled CTs are shown to contribute a small amount of generation around 2 p.m., the time of peak demand.

¹²The model allows the user to specify different profiles for the wind generation over the course of a 24-h day for each of the areas in the west. For this particular simulation, a flat profile was selected for the ease of comparison.

For the CO₂ analysis, the most important segment is the coal generation, the segment shaded in black. Coal is simulated to provide 28% of the region’s generation for a summer day at the end of the base case simulation. But coal is the most carbon intensive form of generation, and its contribution to CO₂ emissions is much higher than one might think from its contribution to total generation.

8. Simulated impact of carbon prices

Fig. 9 shows the corresponding simulation results if carbon prices follow the upward trajectory in Fig. 2. Fig. 10 shows how the generating technologies would be dispatched during a typical August day in the final year of the new simulation. A comparison with the previous chart shows that the carbon prices would lead to around 9% less demand because of the consumers responding to higher retail rates.¹³ There is no additional investment in hydro capacity, and the hydro conditions are the same as in the base case: each year is an “average year” and the operators are able to shape some of the generation into the peak hours. Consequently, hydro generation is the same as in the base case simulation. Nuclear generation is also the same as in the base case. Some argue that the nation will see a

¹³With carbon prices, many distribution companies would probably accelerate their conservation programs to encourage customers to invest more heavily in energy efficiency. We ignore the likely acceleration of conservation programs in this simulation to take a cautious position on carbon prices.

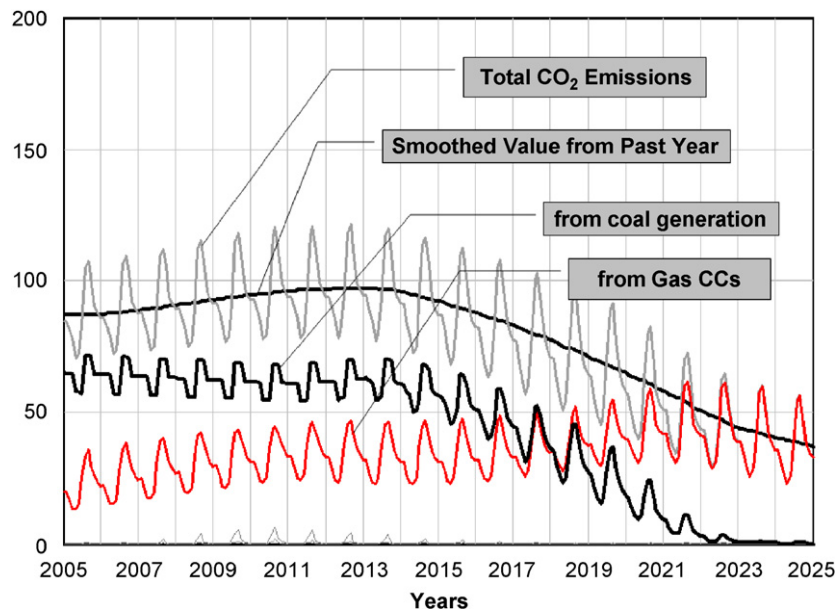


Fig. 9. CO₂ emissions (MMTC/year) in the first scenario with carbon prices in Fig. 2.

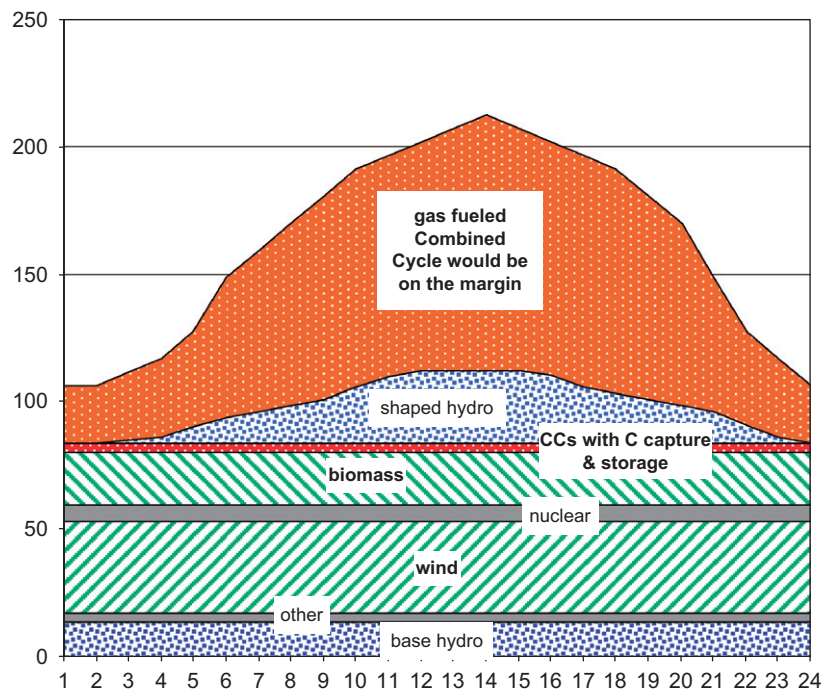


Fig. 10. Generation for a typical August day in the final year of the simulation with carbon prices.

greater investment in nuclear capacity with carbon prices. Given the many uncertainties on nuclear plant performance and on waste disposal, we decided to simulate carbon prices without any additional nuclear capacity. This assumption maintains the conservative approach to estimating the impacts of a carbon market.

Fig. 10 shows large contributions from wind and biomass generation. Wind construction is especially important in the simulations shown here. With a combination of a carbon allowance market and a production tax

credit (PTC), the western system could experience 19% annual growth in wind capacity.¹⁴ By the end of the

¹⁴The 19% annual growth in wind capacity is caused by a combination of rapid growth in demand and the favorable economics of wind investment. According to *The Wall Street Journal* (July 9, 2007), worldwide wind capacity has grown by around 24%/year during the past 6 years. This rapid growth has strained the capacity of the wind turbine manufacturers (i.e., Vestas, Gamesa, GEWind), and some wind developments have been stalled due to delivery delays. The WECC simulations ignore delivery delays in wind and other forms of generating capacity.

simulation, wind would provide 25% of total generation. This would match some of the contributions envisioned by the European countries noted in Fig. 6.

The costs of expanding wind generation and biomass generation in the west will be substantial, and these costs are included in the simulations. This paper takes a cautious position on these renewable technologies: there is no reduction in their costs as more capacity is constructed and operated. Indeed, we adopt the opposite assumption: we assume that the cost of the marginal generator becomes increasingly expensive with increased investment in both wind capacity and biomass capacity. The simulations teach us that carbon market will allow wind and biomass investors to pay these extra costs.

An important conclusion from Fig. 10 is that CCs with carbon capture and storage technology provide only a minor contribution (around 2%) by the end of the time interval. This small contribution arises from the high cost of this new technology and the assumption that it would not become available until the final years of the simulation.

The most important result from Fig. 10 is that coal generation could be completely eliminated by the end of the simulation. Coal generation was highlighted in black in the previous chart of a 24-h day. It accounted for 28% of the generation, but it was responsible for two-thirds of the carbon emissions. But coal generation could be eliminated entirely. This is achieved in two phases. The first phase is the elimination of investment in new coal plants, which takes place immediately after the carbon market opens in the year 2010.

The second phase takes longer. As the price of carbon allowances increases over time, the variable cost of coal plants is driven upward. Since coal is the most carbon intensive fuel, coal plant operating costs will eventually exceed the operating cost of gas-fired CCs. When this happens, the less efficient coal plants are pushed to the top of the stack in the daily operation. As carbon prices continue upward, even the more efficient coal plants will not be able to compete with gas CCs. Eventually, coal plants will only be able to justify operating for a few hours each day, but this mode of operation is not feasible. When these conditions are encountered, the model retires the coal plants with infeasible operation.

The coal plant retirements occur mainly around 2020–2025, and the model shows no coal plants in operation by the end of the simulation. The massive retirement of coal-fired power plants is a further stimulus for construction or carbon-free generation since the scenario envisions that construction is timed to keep pace with the growth in demand and to replace retirements. The model responds to the major retirements (around the year 2020) by investing in new construction that will be needed to maintain adequate reserve margins.

Fig. 11 shows the wholesale prices in the scenario with carbon prices. The highest and most variable price is the peak-hour price. The lowest price is at 2 a.m. The bold curve is the average daily price which is indicative of the

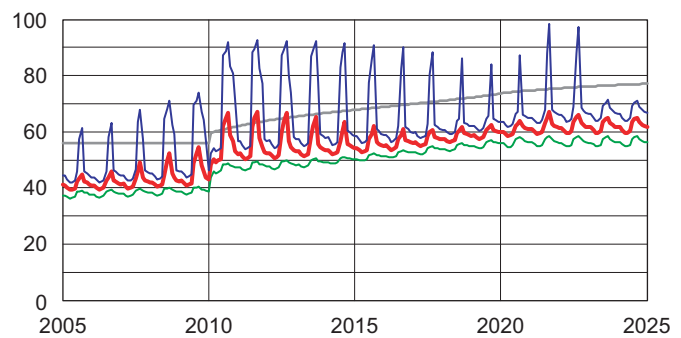


Fig. 11. Wholesale prices (\$/MWH) in the scenario with carbon prices.

revenues earned in the wholesale market. The remaining curve shows the investor's full cost for new generation. The carbon market opens in 2010 with allowances costing around 22\$/MWH. The allowance cost increases over the next 15 years to around 60\$/MWH. The cost of these allowances influences all three of the wholesale price trajectories and it drives up the investors' weighted average cost of building new generating capacity.¹⁵ The simulation begins with investors needing 55\$/MWH to make good on their investment. This cost jumps when the market opens in 2010, and it increases throughout the remainder of the simulation.

Fig. 11 allows one to compare the investors' cost with the average daily price. This difference is around 14\$/MWH at the start of the simulation. This extra cost is the "implicit capacity payment" associated with the long-term contracts that distribution companies would sign with power plant investors. This implicit payment declines somewhat during the period from 2006 to 2012. But, by the end of the simulation, the implicit payment returns to around 14\$/MWH. The wholesale prices are combined with the implicit capacity payment to obtain the cost of generation. Generation costs are passed through to retail customers after a 1-year regulatory lag. The generation costs are combined with costs of transmission and distribution to obtain the average retail price of electricity. The overall impact is a 23% increase in retail prices by the end of the simulation.

9. A scenario with slower growth and a shift to coal plants in the east

The previous simulations assumed that demand would grow at 2.5%/year in the absence of increases in the retail rates. But 2.5% annual growth is at the high end of the range of forecasts we have encountered in our research. To test a quite different situation, we selected demand growth

¹⁵The total cost of gas and coal fired power plants are increased directly when the cost of allowances drives up their variable costs. The total cost of wind and biomass plants increase indirectly. They tend to increase over time as more tree farms and wind farms are located at difficult locations in west, as explained by Ford (2006).

rates that match mid-range estimates. The annual growth trend was set at 1% in the northwest, 1.5% in California, 2% in the Rocky Mountain pool and 2.5% in the southwest. The overall effect of these assumptions is a slower, but more realistic growth in demand.

The prices of natural gas have increased far above \$5.50 per million BTUs recently, and some experts predict that gas prices could remain at the high levels in the coming decades. To test this possibility, we assume that long-term gas prices will be \$7.50 rather than \$5.50 per million BTUs. The \$7.50 is lower than recent spot market prices for natural gas, but it happens to match the “high gas” case used by the EIA (2003, p. 157). The higher gas prices will lead to an increase in the retail electricity rates, and higher electric rates will depress the demand below the growth trends mentioned previously.

The higher price of natural gas provides a strong boost for coal-fired power plants. We would expect CCs to compete poorly in the new scenario, and coal plants to capture a much larger market share. However, coal plants are not likely to be constructed in the state of California because of air quality regulations. Some believe that the west would benefit from major investments in transmission lines to bring coal-fired generation from the coal-rich areas in the eastern part of the WECC to the major load centers in California, Oregon and Washington (Frontier Line, 2005; RMATS, 2003).

To represent these proposals in a general manner, we give coal plants an additional boost by a change in the fraction of capacity needs that are shifted to the east. The base case assumes that power plants are constructed within each area to meet the growth in demand in that area. In the new simulation, we assume that 50% of the need for new capacity in the coastal areas will be met by construction in the neighboring areas to the east. In the case of Southern California, for example, 50% of the need for new capacity will be met by construction in the southwest. With the slower growth in demand, the initiation of new construction would be delayed until 2012. This postponement makes sense because utilities can meet the reserve margin goal even if new construction is not started until 2012. Once construction is started, the number of power plants added each year will be less than the previous case because of the slower growth in demand. The high price of natural gas causes the gas-fired CCs to capture only a small fraction of the market. Wind and biomass projects account for around 55% of new construction in 2012. But their market share declines during the simulation as investors turn to less advantageous sites for tree farms and wind farms. Coal plants capture 40% of the market when construction starts in 2012. Their market share grows to 70% by the end of the simulation.

By the year 2025, the total emissions are somewhat less than in the first scenario. Carbon emissions are cut by 63% at the end of the simulation, somewhat less than the 75% reduction in the previous base case. The smaller reduction is caused by the higher natural gas prices, which give the

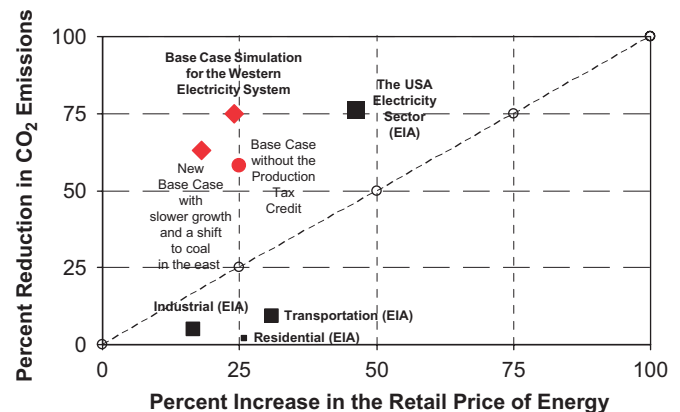


Fig. 12. Summary results for the simulations reported in this paper.

older coal plants a longer opportunity to operate despite the high cost of carbon allowances. This change in relative operating costs slows the phase-out of coal plant operation in the new S139 simulation.

10. Summary of results

Fig. 12 summarizes the long-term impacts of carbon prices for both scenarios. We put the WECC result in perspective with the same chart used previously to summarize the EIA findings. The purpose of this chart is to learn if the WECC model would show simulated results well above the 50/50 line. The base case results have been described in detail. By the year 2025, the end result was a 75% reduction in carbon emissions and a 23% increase in the average retail rate for electricity. This result is extremely encouraging, as it shows the western system could achieve the same dramatic reduction in CO₂ emissions that the EIA projected for the nation as a whole. The retail rate result is also encouraging. The base case simulation shows that the rate increase would be half as large as the EIA projected for the entire nation.

The second result in Fig. 12 summarizes the scenario with slower growth in demand and a major shift to coal plant construction in the eastern areas. This is a dramatically different view of the future of the western electricity system. The new simulations show that carbon emissions would be reduced by 63%, and the retail price of electricity would be increased by 18%. These results also lie well above the 50/50 line, providing further confirmation that the western electricity system would lead the way in reducing carbon emissions.¹⁶

¹⁶The same carbon prices were used in both scenarios. The higher prices for natural gas in the second scenario lead to less fuel switching between coal and gas CCs, so there is somewhat less reduction in CO₂ emissions. Under such conditions, a full analysis of CO₂ emissions in the entire US might indicate that higher carbon prices are needed to comply with the goal of S139. If higher prices were used in the simulation study of the WECC, we would see the new result shift up and to the right because there would be greater reduction in emissions and a larger increase in retail rates.

Numerous tests have been conducted to learn if the simulated impacts are changed in an important manner by changes in the assumptions. Many of the simulations yield essentially the same results as found in the previous comparison. For example, the new results would be located close to the position of the base case result, and all tests conducted to date show results that lie well above the 50/50 line. One of the more important inputs to the model is the renewable generators PTC. This federal incentive amounts to 13\$/MWH reduction in total costs for wind and biomass. This is an important incentive to encourage investment in wind, biomass and other forms of renewable generation. At the time of the EIA analysis, there was considerable uncertainty about the extension of the PTC, and their analysis was conducted without the PTC. However, the PTC was recently extended by the Energy Policy Act of 2005, so it has been in effect in both the base case and the S139 simulations. To learn the importance of the PTC, we repeated the simulation without the tax credit. Fig. 12 reveals that the removal of the PTC lowers the reduction in carbon emissions but leaves the rate increase approximately the same. Relative to the 50/50 line, the overall result is the same as in the base case—the electricity sector results are well above the 50/50 line, indicating the electricity sector could still lead the way in reducing carbon emissions.

11. Implications for the creation of a national carbon market

The national impacts of The Climate Stewardship Act are described in detail in the report by the EIA (2003). The creation of a carbon market would allow the US to bring the nation's emissions back to the value estimated to have occurred in the year 1990. For those who wish to see continued growth in the nation's GDP, there will be a price to be paid for bringing our GHG under control. But the price is a small. According to the EIA (2003, p. 206), the GDP annual growth would be reduced from 3.04% to 3.02%. One reason for the small impact is that the cap-and-trade market would elicit major reductions in GHG emissions from the industries with the greatest ability to respond. The EIA study revealed that the electric power industry would be the most responsive. This paper shows that the electricity system in the western US would match the response expected for the nation as a whole. In a scenario with rapid growth in demand, for example, CO₂ emissions in the west could be cut by 75%. These results provide further support for those calling for the implementation of a national carbon market.

But some may argue that it is premature to initiate a national market for carbon allowances until we have more confidence in the costs and performance of advanced, carbon-neutral technologies. For example, some might argue we should put a carbon market on hold while we invest in the development of advanced nuclear technologies or in advanced technologies for carbon capture and storage. The simulations shown in this paper indicate that such advanced technologies would not be crucial to the

western system response over the next two decades. This result emerged in a simulation with rapid growth in demand and with conservative assumptions on proven technologies for wind and biomass generation. Wind and biomass generation are simulated to provide 37% of total generation even with the conservative assumption that there will be no improvement in their performance during the next 20 years. Advanced, carbon-neutral technologies, on the other hand, play only a minor role. These results suggest that a carbon market does not need to be placed on hold while we await the development of advanced, carbon-neutral generating technologies.

12. Uncited References

Dimitrovski et al., 2007; US Department of Energy and the Energy Information Administration, 2000; Herzog and Golomb, 2004.

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