System Dynamics and Power Systems Simulation of the Carbon Emissions from the Electricity System in the Western U.S.A. and Canada

Andrew Ford
Program in Environmental Science and Regional Planning
Washington State University
Pullman, Washington 99164 – 4430

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ABSTRACT

This paper describes a computer simulation analysis of a cap and trade market to control carbon emissions in the western electricity system spanning eleven western states and two Canadian provinces. This analysis is the first major application of a new approach to computer modeling of large-scale power systems. The simulations show the impact of the carbon market prices that could arise from Senate Bill 139, The Climate Stewardship Act of 2003. The simulations indicate that the carbon prices could lead to dramatic reductions in carbon emissions over the next two decades. The simulations reveal that the reduced emissions can be achieved with only half the increase in retail electricity rates that have been predicted for the nation as a whole. Generation from advanced technologies for carbon sequestration are not required for the western system to achieve the dramatic reduction in CO2 emissions. Renewable generation from wind and biomass generators play a much larger role. The growth of crops dedicated to electricity production is particularly relevant to Brazil, the world's leader in the production and export of biofuels.

Key Words: carbon dioxide emissions, carbon allowance markets, Climate Stewardship Act, electricity markets, power plants, transmission network, renewable resources, system dynamics, computer simulation

Introduction

The accumulation of greenhouse gas (GHG) emissions in the atmosphere is arguably the most serious environmental threat of our time. In the USA, the seriousness of the problem has been recognized by the US Congress in a recent "Sense of the Senate Resolution" (Domenici and Bingaman 2006), in which the Congress finds that 'there is a growing scientific consensus that human activity is a substantial cause of greenhouse gas accumulation and mandatory steps will be reqauired to slow or stop the growth of greenhouse gas emissions into the atmosphere." The resolution calls on Congress to enact a comprehensive, mandatory program of market-based limits on greenhouse gas emissions to slow, stop and reverse the growth of GHG emissions in a matter that "will not significantly harm the Unites States economy" and which will "encourage comparable actions by other nations."

Carbon dioxide (CO2) emissions are the largest GHG, accounting for over 80% of the emissions in the USA (EIA 2003, p. 35). The USA produces more CO2 emissions than any other country. (The emissions in the USA are around 20-times higher than in Brazil, for example). 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 total energy related emissions in 2001(EIA 2003, p. 36).

Figures 1-2 provide perspective for this paper by showing the nation's GHG flows and its energy flows. Figure 1 depicts the greenhouse gas emissions in the year 2004. Sources of fuels enter the diagram on the left and the emissions from using the fuels exit on the right. The arrows are sized to represent emissions in million metric tons of CO2 equivalent, hereafter abbreviated as MMTCO2. (Units and acronyms are listed at the end of the paper.) The combustion of fossil fuels in the electricity sector was responsible for 39% of energy-related emissions and 33% of the total emissions. This large contribution alerts us to the importance of the electricity sector to the greenhouse problem.

Figure 2 shows the nation's energy flows in the year 2000 with sources of energy on the left and the uses of energy on the right. The arrows are sized to represent the amount of energy measured in "quads" (quadrillions BTUs). Electricity generation required 40.4 quads in the year 2000, and coal provided 20.5 quads of the needed energy. The diagram shows that coal is used almost exclusively for electricity generation, and coal-fired power plants provided over half of the nation's electricity generation in the year 2000.

This paper will explain 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. This responsiveness is the focus of this paper.

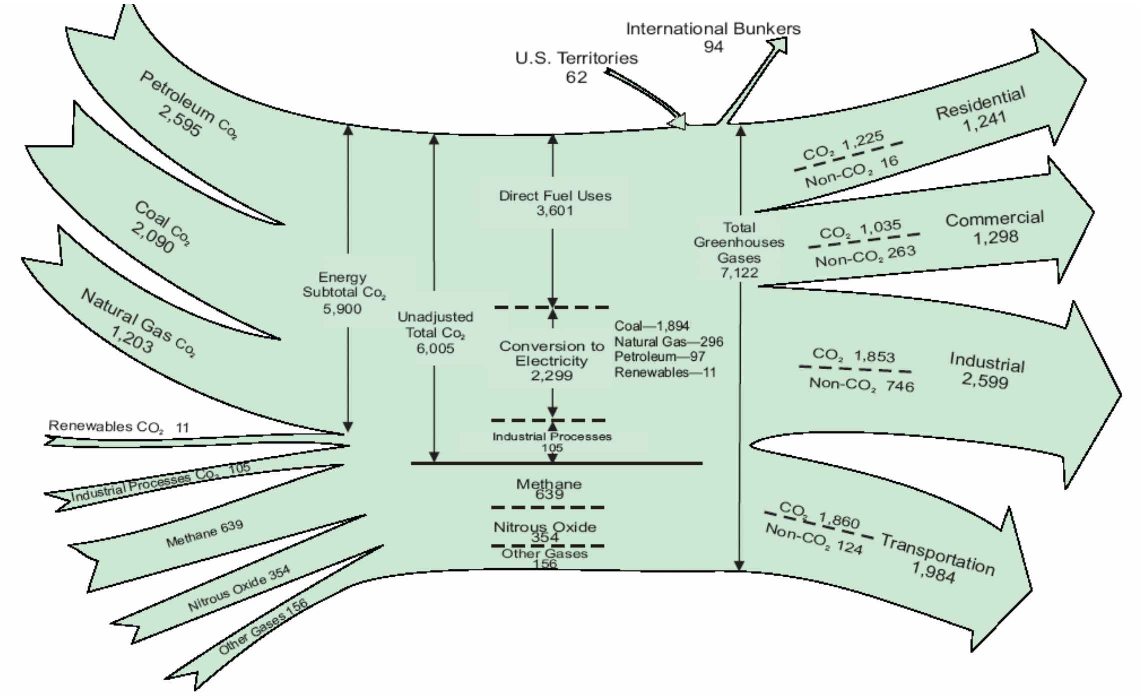


Figure 1. Greenhouse gas emissions in the USA in the year 2004, measured in million metric tons of CO2 equivalent (MMTCO2). Data and diagram from the EIA (2005).

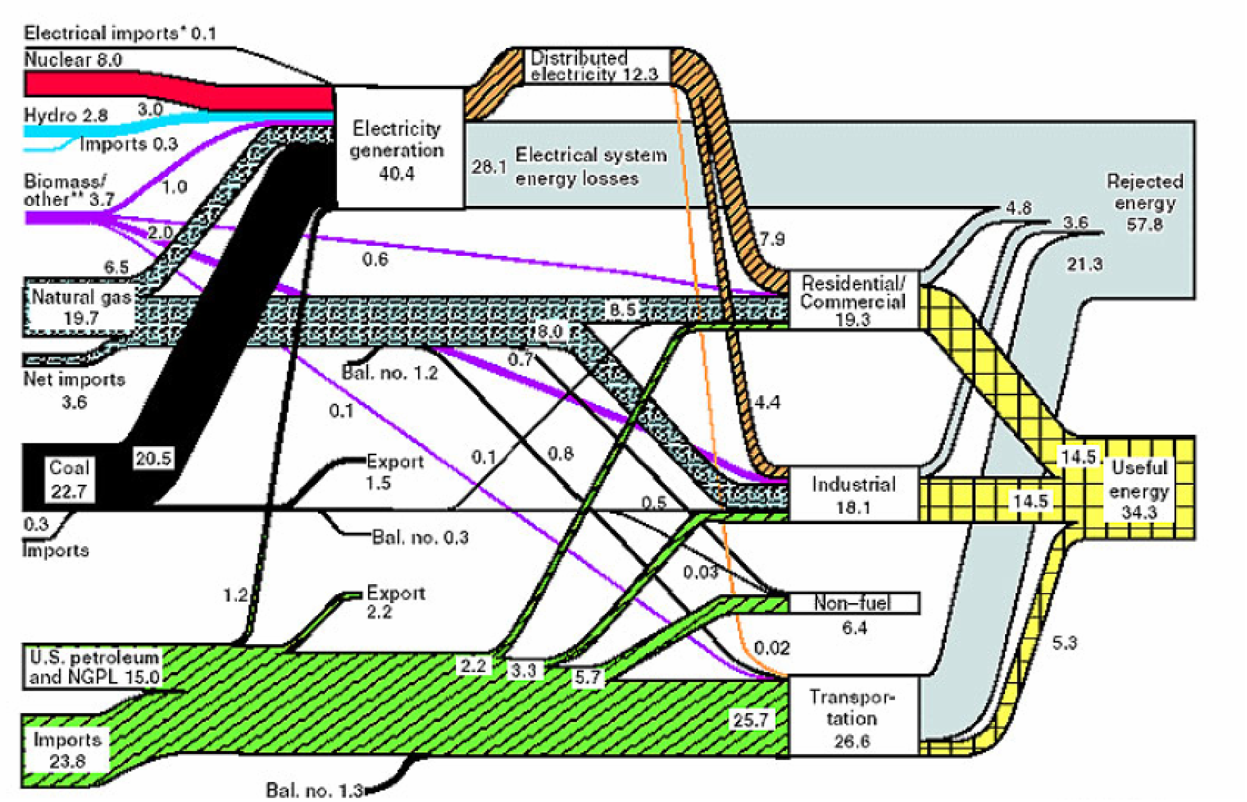


Figure 2. Annual energy flows in the USA in the year 2000, measured in Quadrillion BTUs. (Data from the EIA (2000); diagram from the Lawrence Livermore National Laboratory.)

The Climate Stewardship Act

In January of 2003, Senators McCain and Lieberman introduced Senate Bill 139 (S139). The Climate Stewardship Act called for a cap and trade system for GHG, similar to the cap and trade approach to control sulfur dioxide emissions in the US. S139 would set the phase I cap on GHG emissions at the value from the year 2000. This cap would apply from the market opening in 2010 until the year 2016. After 2016, a phase II cap would limit GHG emissions to the value from the year 1990. S139 did not pass, but it did receive 43 votes in the Senate.

S139 has been the subject of detailed studies by MIT (2003) and by the US Energy Information Administration (EIA 2003). The EIA study found that the US could reduce GHG emissions to meet the targets with relatively small impact on the economy as a whole. The EIA expected Gross Domestic Product (GDP) to grow 3.04 %/year over the next twenty years in a base case scenario. With S139 in effect, the nation's GDP was projected to grow at 3.02 %/year (EIA 2003, p. 206). The EIA analysis indicated that the nation's electricity sector would lead the way in reducing GHG emissions.

Figure 3 summarizes the key results from the EIA analysis of the nation's electricity sector. Emissions are shown in million metric tons of carbon equivalent (MMTC) on the left scale. There were 621 MMTC in the year 2000. By 2025, electricity sector emissions would reach 868 MMTC, 40% higher than in the year 2000.

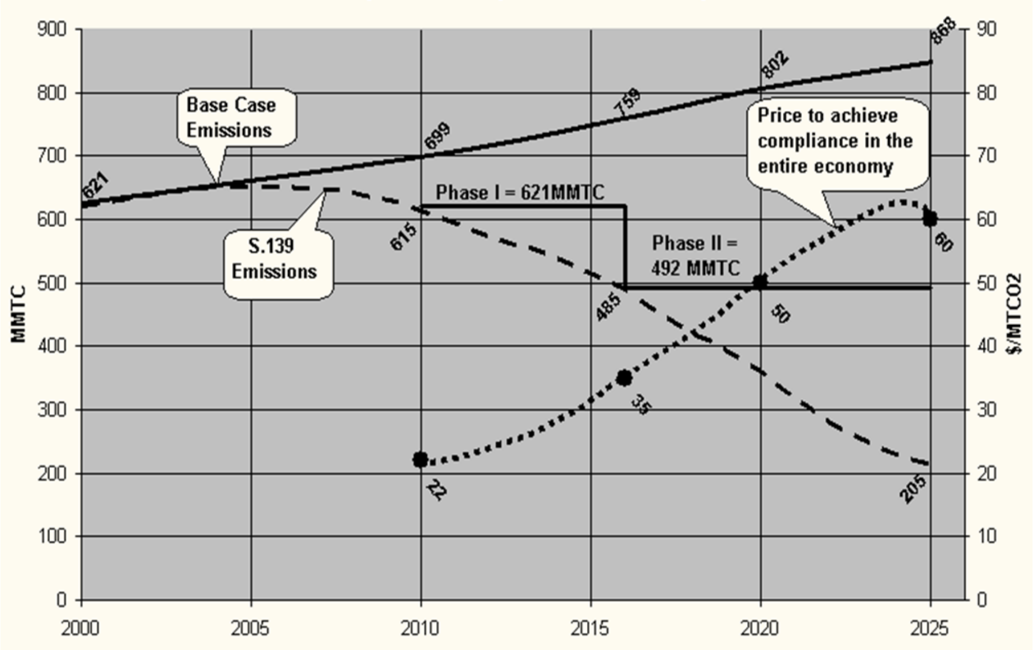


Figure 3. Summary of the EIA analysis of the nation's electricity sector response to S139.

Figure 3 shows the cost of carbon allowances in $/MTCO2 on the right scale. 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. Over the next 15 years, the price would rise to 60 $/MTCO2. The EIA estimated that these prices would be sufficient for the nation to achieve the goals specified in S139. Figure 3 shows that the electricity sector emissions would be reduced dramatically. Indeed, the electricity sector emissions would decline well below the allowances available to this sector. This means the electricity sector would have extra allowances that could be banked for future use or sold to less responsive sectors in the economy. For the purpose of this paper, the main finding from the EIA study is that the electricity sector would 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.

Figure 4 puts these main results in perspective by showing CO2 reduction on the vertical axis and price increases on the horizontal axis. The graph is divided into diagonal halves by a 50/50 line to help us see which sectors would be most responsive under S139. The idea behind cap and trade markets 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. The transportation, industrial and residential sectors would fall well below the 50/50 line. The electricity sector is well above the line. It is expected to lead the way in reducing carbon emissions.

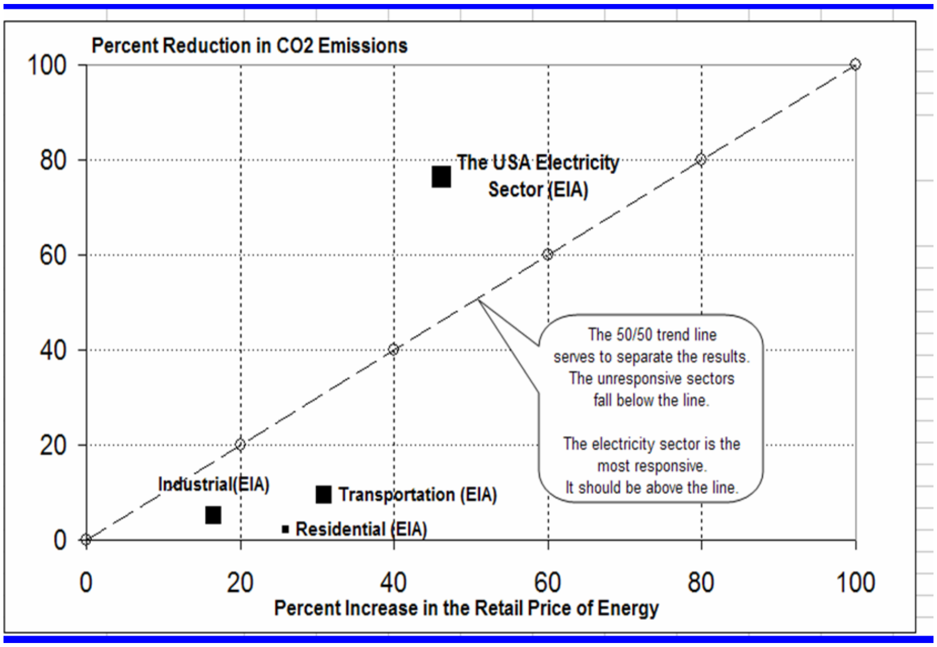


Figure 4. Summary of the EIA estimates of long-term impact of S139.

Could We See Simular Results in the Western Electricity Market?

The question for this paper is whether the electricity system in the western USA and Canada could deliver similar results under S139. We focus on the electricitty sector, the most responsive sector in the EIA report. The EIA analysis showed that the main reduction in CO2 emissions in the electricity sector is achieved by a reduction in coal-fired generation. Coal generation is most carbon-intensive form of electricity generation. It provides just over half of the nation's electricity generation with a large concentration of coal-fired power plants in the mid-west. In the west, however, hydro-electric generation and gas-fired generation are more much more important than in the rest of the country. Coal generation accounts for around 30% of the generation in the WECC. With smaller dependence on coal, the western markets might be expected to deliver a smaller reduction in CO2 emissions under S139.

But the west has the potential for renewable resources that might allow it to match or exceed the EIA projections for the nation as a whole. A key resource is wind. According to the Western Governnors' Association, the west has a potential for 250 GW of wind capacity at a cost of 60 $/MWH or less (WGA 2005, p.2). And according to Renewable Northwest (2004), the wind resources in the state of Montana alone could provide 15% of the generation for the entire USA. These large resources are part of the reason why several western states have issued Renewable Portfolio Standards (RPS) which call for an increasing fraction of total generation to be provided by renewable generators (Ford 2005, WGA 2004). Analyses of RPS typically estimate that three-quarters of the required renewable generation would come from wind (Ford 2005).

The EIA study of S139 did take wind resources into consideration. They noted that wind generators provided 0.2% of generation in the US in the year 2000. They then projected that this would grow to 0.6% by the year 2025 under base case conditions. This projection leaves one with the impression that there is little room for wind generation to contribute to the nation's electricity generation. However, with the carbon allowance prices envisioned in Figure 2, wind investors would be in a much stronger position to compete against the fossil fueled generators. According to the EIA, wind generation could provide 6% of the nation's electricity generation by the year 2025, a ten-fold increase compared to the base case projection. At first glance,a ten-fold increase in wind generation appears to be a dramatic reaction to S139. But the relative size of the response is dramatic only when compared to the low value of 0.6% projected under base case conditions.

Figure 5 provides a different perspective by placing the EIA projections next to the wind contributions expected in European nations with a strong national commitment to wind investment. Germany leads the world in installed wind capacity. Wind provided 4.3% of load in 2003, and a recent study shows the feasibility of reaching 14% generation by the year 2015. And according to the German wind energy institute, wind power could be providing 30% of German electricity demand by 2030, with over half of the generation out to sea (EWEA 2004, p. 35). Spain ranks second in the world in terms of installed wind capacity. Wind provided 6.5% of their generation last year. By 2011, wind power could expand to 23 GW, enough to cover 16% of Spain's electricity demand (Aubrey 2005, p. 17). Denmark has achieved the highest relative contribution from wind, with 20% of generation in 2004 (DANSK 2006). Their goal is for 35% by the year 2015.

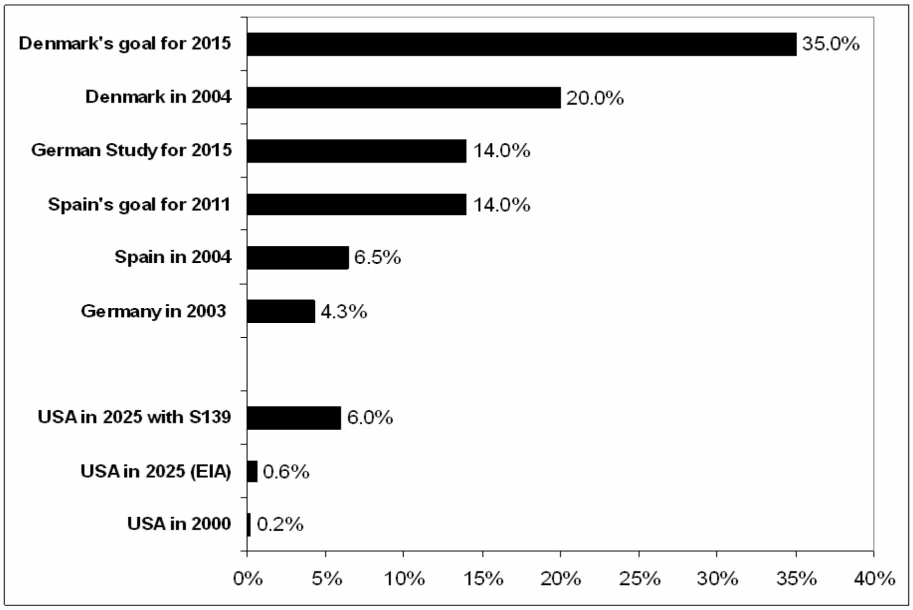


Figure 5. Fractions of electricity generation from wind.

These goals are stressed here because of the huge wind resources in the western USA. This paper uses system dynamics simulation to show that these resources could play a major role in the WECC response to the carbon market envisioned in S139.

The WSU Model of the WECC

Figure 6A shows the opening view of the WSU model to simulate electricity generation, transmission and consumption with a particular interest in CO2 emissions. The opening view serves as a starting point for navigating through the many views of the model. The green comments link to views of results; the gray comments link to views of the model structure. When clicking on the "tranmission capacity" link, for example, one sees the portrayal of the transmission system shown in Figure 6B.

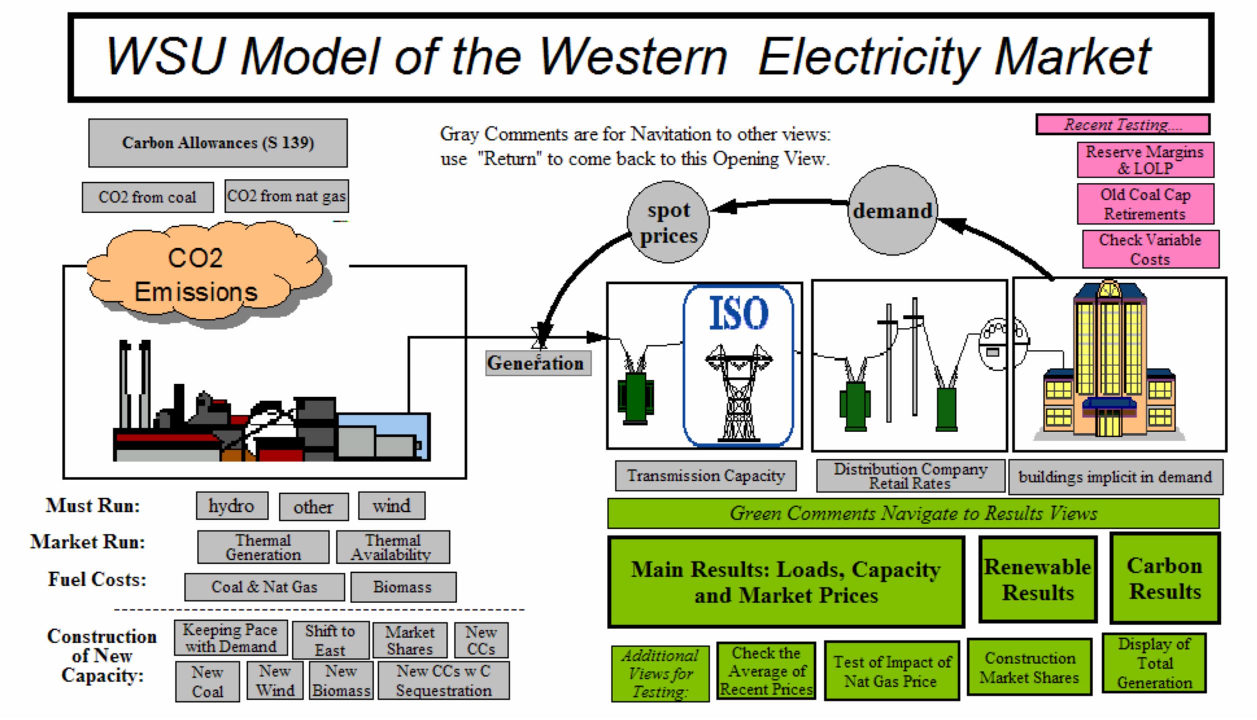


Figure 6A. Opening view of the model.

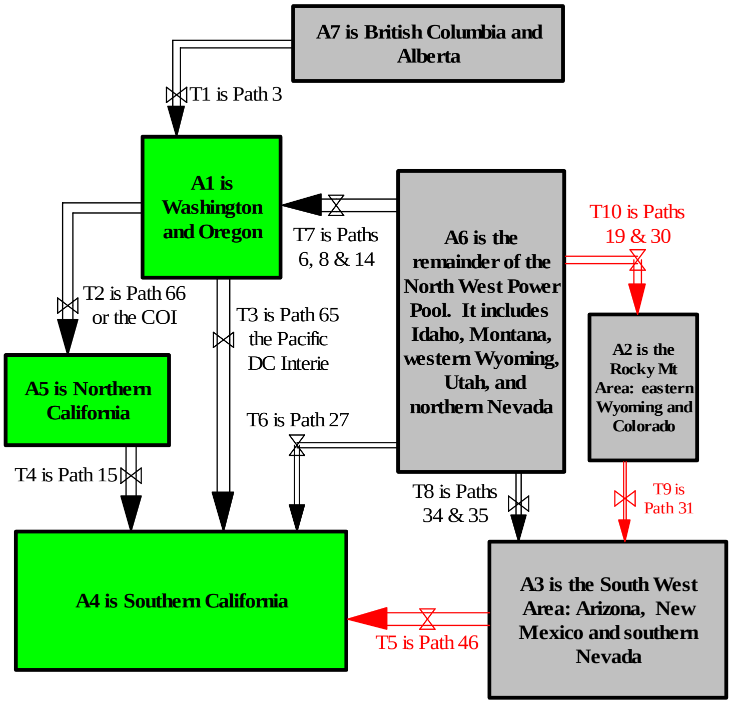


Figure 6B. View of the transmission capacity network in the west.

With around 50 views, the model is far larger than can be described here. However, we can show some selected results to set the stage for the analysis of S139. Further details on the modeling method are given in a separate conference paper (Ford 2006).

The model was designed for simulation studies of a wide variety of scenarios for the future of the western system. For example, natural gas prices may remind high, or they could return to values predicted by the EIA study of S139. 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.

We consider two scenarios in this paper. The first scenario 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. Rapid growth is useful for the first scenario because the west will face the need for significant construction of new generating capacity to maintain adequate reserve margins. The first scenario envisons natural gas prices at the values expected by the EIA in the S139 study, so gas-fired combined cycle (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.

The second scenario is quite different. The growth in load will be much lower, approximately at the estimates by recent forecasts. Natural gas prices will be much higher, giving a strong advantage to coal investors. The new scenario envisions a major expansion of transmission corridors to link the coal and wind resources in the eastern areas with the coastal load centers. This policy also gives a strong advantage to coal investors.

These scenarios provide two starting points for an analysis of S139. Our goal is to learn if the western system can deliver the dramatic reduction in CO2 emissions that have been estimated for the nation as a whole. This paper provides a detailed explanation of each scenario to aid our understanding of the system. Some readers may make the mistake of interpreting the simulation results as a forecast of the future of the WECC. I emphasize that the results are not a forecast of the most likely condition in the western markets. Readers who are looking for a forecast should look elsewhere.

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. The model operates with time in months with a typical 24-hour day in each month of the year. The results are shown in the time graphs in Figures 7 – 10. (The model operates in months, but the time graphs show years on the horizontal axis for ease of interpretation.) The variation in results within each year are caused by variation in loads and hydro generation during the different seasons of a year.

The Scenario with Rapid Growth and Construction Dominated by Gas CCs

Figure 7 shows the growth in peak loads in the first scenario. The annual peak load appears at 2 pm in August of each year. The monthly peak loads are lowest in the spring months of each year. The annual peak load in 2005 is just under 150 GW. We selected an annual growth trend of 2.5% in all areas, but the actual growth in demands can deviate from the user-specified trend depending on the consumers' response to retail rates in each area. Retail rates are relatively constant in the base case simulation, so the upward trend in Figure 7 is essentially constant at 2.5%/year.

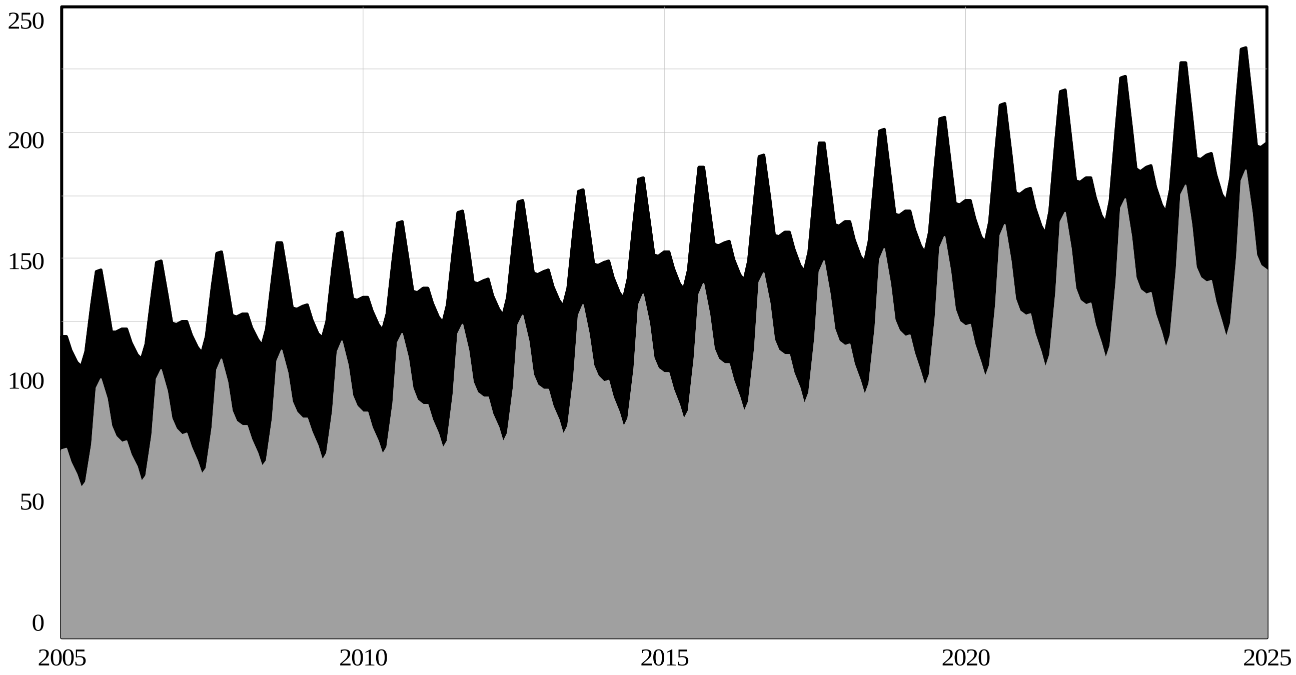


Figure 7. Peak Loads in the first scenario (in GW).
The peak load met by must-run generation is in black. The peak load met by market generation is in gray.

Loads are satisfied by a combination of “must run” and “market run” generation. Must-run generation includes hydro, wind and other generation. Generation from these units is controlled by the amount of capacity and the user-specified shapes for generation within the hours in a day and the months of the year. Hydro-generation, for example, is shaped to contribute more during the peak hours of each day and during the peak river flow months of each year. The thermal generating units are treated quite differently. These are “market-run” generators whose hour-by-hour operation is governed by the wholesale price of electricity compared to their variable cost of operation. The thermal generators operate in a simulated spot market, so the spot price must rise sufficiently high to satisfy the demand placed on the market in each hour of the day. The prices are calculated for a typical day for each of month of the simulation.

Figure 8 shows the wholesale prices in the first scenario. The peak price is from 2 pm, the off-peak price from 2 am. The average daily price is a simple, arithmetic average of the prices for each hour in the 24-hour day. Peak prices in the first year rise to just over 60 $/MWH in the summer months. Peak prices are around 70 $/MWH by the end of the simulation. Off-peak prices are relatively constant at just under 40 $/MWH. Figure 8 emphasizes the average daily price because this is the best indicator of the revenues to be earned in the wholesale market. The simulation begins with average daily prices at around 42 $/MWH and ends at around 44 $/MWH.

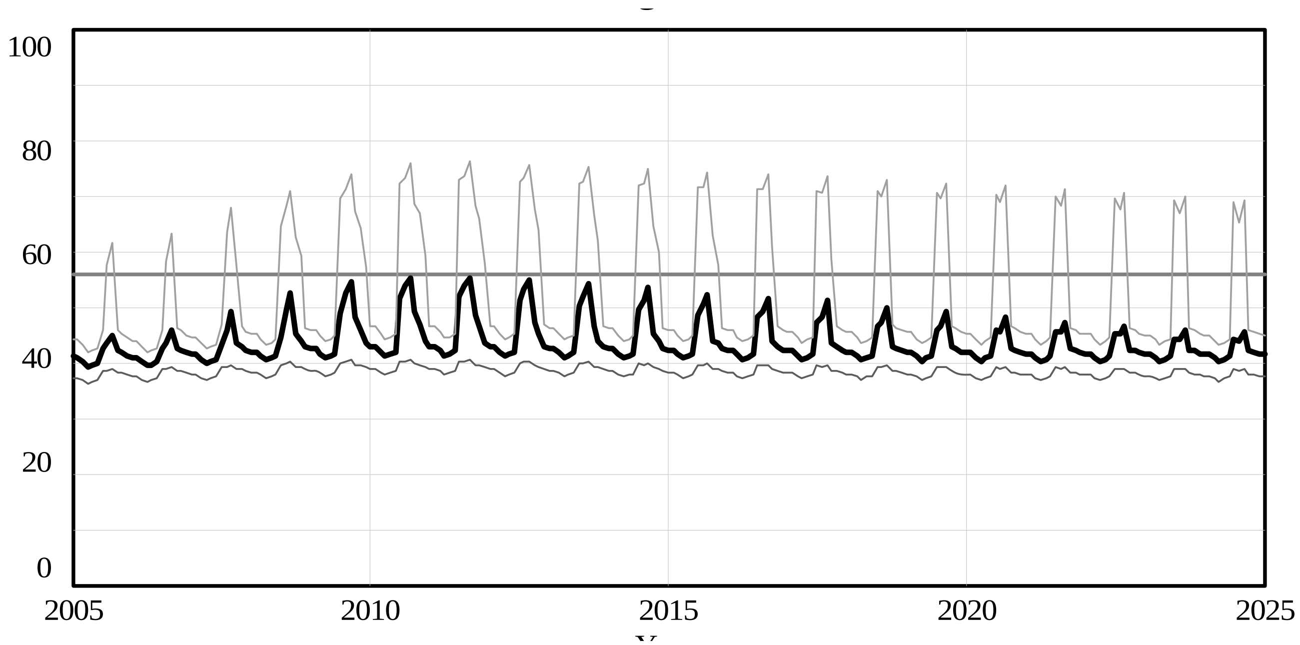


Figure 8. Wholesale prices ($/MWH) for electric energy in the first scenario.
The peak price is in light gray; off-peak price in dark gray; average daily price in black.
The investor’s full cost of building new capacity in one of the areas is the flat, gray line.

Figure 8 puts the average daily prices in perspective by showing the weighted average cost of investing in new generation. Investors would face an average cost around 56 $/MWH over the entire simulation. An important result from Fig. 8 is that daily average spot prices would fall far short of providing the investors the prices they need to justify such investments. The relatively low wholesale prices at the start of the simulation are caused by the large amount of generating capacity currently available in the WECC. The simulation begins with a planning reserve margin of 33%. Although the simulation is running with average hydro generation, this measure of reserves is calculated as if the hydro system experiences “critical conditions. Planners normally call for resource plans which aim for a reserve margin of around 15% under critical conditions. Thus, the initial simulation begins with approximately twice the reserves thought necessary for reliable operation in a year with low hydro generation. This starting condition matchesWECC loads and resources described by McCollough (2005).

Figure 9 shows the loads and resources in the simulated spot market for thermal generation. The simulation begins with over 160 GW of thermal capacity, and this grows even higher during the first year as the capacity initially under construction comes on line. Thermal outages are simulated as a combination of forced outages and planned outages. Forced outage rates are applied uniformly over the year. Planned outages are controlled by user-specified factors to concentrate much of the planned maintenance in the spring. The middle curve in Figure 9 shows the thermal capacity available after derating for the effect of outages. The lower curve is the “peak load to market.” The simulation begins with around 100 GW of peak load to market in August of the first year. The reserves in the thermal market are apparent by comparing the lower two curves in Figure 9.

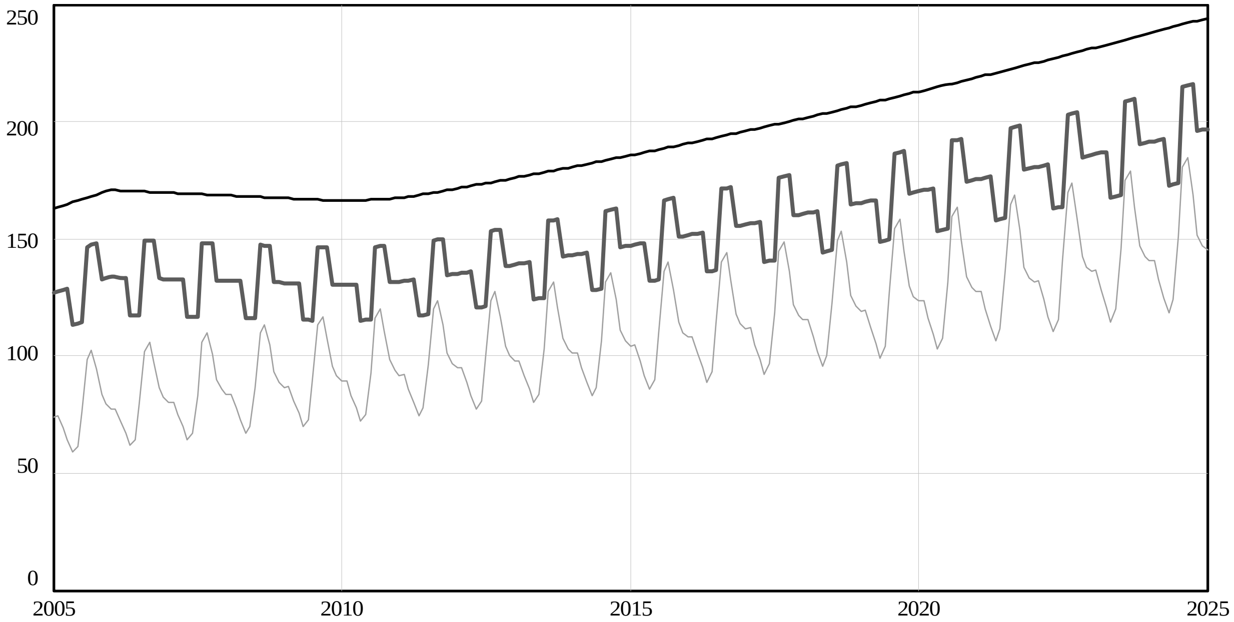


Figure 9. Peak loads (GW) to be served by the market for thermal generation in the first scenario. The total thermal capacity is the top curve. Total thermal capacity available is in dark gray. The peak load to be served by the market is the lower curve.

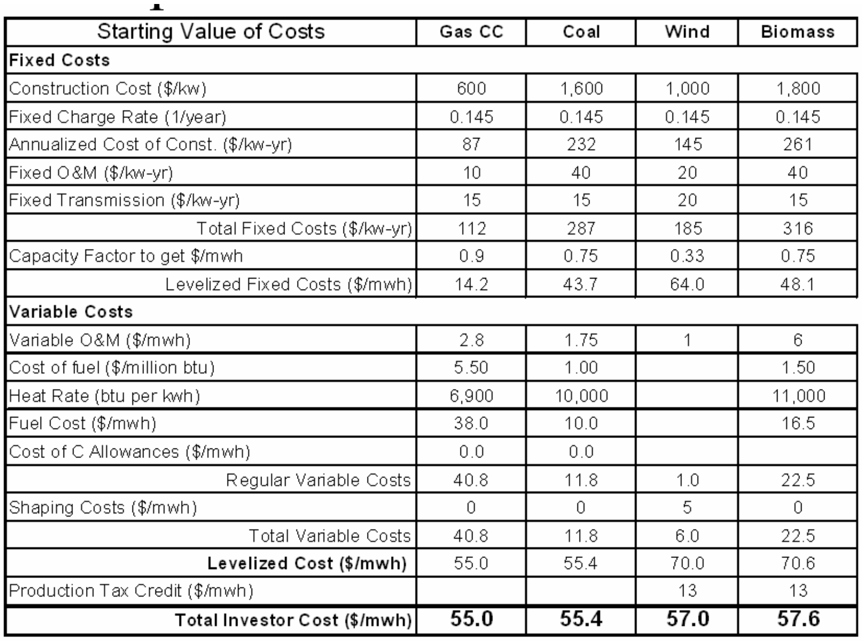
The base case simulation assumes that no new construction is initiated for several years because of the high reserves. Consequently, the thermal capacity declines somewhat due to retirements. We assume that new construction will be initiated around the year 2008, as this initiation causes planning reserve margins to fall gradually into alignment with the 15% goal often used in resource planning. Figure 9 shows thermal capacity growing again around the year 2010. The capacity grows for the remainder of the simulation based on the assumption that construction will keep pace with growth in demand and retirements. This pattern is quite different from recent boom/bust pattern in the west (Ford 2002). The steady, timely pattern of construction rests on the assumption that investors will sign long-term contracts with a premium payment to make up for the low energy prices shown in Figure 8. In other words, there is an “implicit capacity payment” associated with this simulation scenario. The model calculates the size of this payment and includes the payment in the retail rates charged by the distribution companies.

Investors can chose from a wide variety of generating technologies. We simulate the following choices in the base case simulation:

- gas-fueled combined cycle power plants
- coal-fired power plants,
- wind machines, and
- biomass-fueled power plants.

The combined cycle technology was the dominant choice of investors building during the boom of 2000-2001. Depending on the cost of natural gas, CCs could well be the most popular choice in the future. The competition between all four choices is simulated for each of the six areas of the region, which allows for consideration of differences in fuel costs across the western system. This approach also allows us to represent the restrictions on new coal-fired power plants in California.

Table I shows the total investors’ costs for each of the generating technologies These particular costs are for an area like the northwest, an area with ample coal and major wind resources (Ford 2005). The first scenario assumes that natural gas prices are constant at $5.50 per million BTUs, a value commonly forecasted when our research began. Coal prices are assumed to remain constant at $1.00 per million BTUs. The cost of biomass is initially $1.50 per million BTUs. With these assumptions, the total cost for coal plants and CCs are approximately the same, around 55 $/MWH.



Starting Value of Costs	Gas CC	Coal	Wind	Biomass
Fixed Costs				
Construction Cost ($/kw)	600	1,600	1,000	1,800
Fixed Charge Rate (1/year)	0.145	0.145	0.145	0.145
Annualized Cost of Const. ($/kw-yr)	87	232	145	261
Fixed O&M ($/kw-yr)	10	40	20	40
Fixed Transmission ($/kw-yr)	15	15	20	15
Total Fixed Costs ($/kw-yr)	112	287	185	316
Capacity Factor to get $/mwh	0.9	0.75	0.33	0.75
Levelized Fixed Costs ($/mwh)	14.2	43.7	64.0	48.1
Variable Costs				
Variable O&M ($/mwh)	2.8	1.75	1	6
Cost of fuel ($/million btu)	5.50	1.00		1.50
Heat Rate (btu per kwh)	6,900	10,000		11,000
Fuel Cost ($/mwh)	38.0	10.0		16.5
Cost of C Allowances ($/mwh)	0.0	0.0		
Regular Variable Costs	40.8	11.8	1.0	22.5
Shaping Costs ($/mwh)	0	0	5	0
Total Variable Costs	40.8	11.8	6.0	22.5
Levelized Cost ($/mwh)	55.0	55.4	70.0	70.6
Production Tax Credit ($/mwh)			13	13
Total Investor Cost ($/mwh)	**55.0**	**55.4**	**57.0**	**57.6**

Table I. Comparison of the investors' total, levelized costs in the first scenario.

Wind costs are explained in a separate paper (Ford 2005); biomass costs are based on estimates by the CEC, EIA and NWPP. The "shaping cost" may be a new term for some readers. The 5 $/mwh is the initial cost that investors face in managing intermittency in wind generation (EPRI 2006, Ford 2005). The levelized costs in Table I indicate that both wind and biomass would be more expensive than gas or coal. However, wind and biomass investors qualify for the renewable energy production tax credit, a federal incentive which is roughly equivalent to 13 $/MWH. With this important incentive, wind and biomass are only somewhat more expensive than gas and coal fired power plants.

We allocate the market shares among these choices using the logit function. If the four choices happen to have the same costs, they would each win 25% of the market for new construction. If some power plants are somewhat more expensive, they win a smaller share of the market. The logit function uses a shaping parameter to control the extent to which a higher cost option (such as biomass) can capture a small fraction of the market. We believe that the more costly technologies will capture a small market share even though they turn out to be more expensive in a comparison of average costs. One reason for this assumption is diversity of costs within the area. For example, biomass may appear more costly when comparing average costs across a large area. But biomass investors may have lower cost opportunities in a particular portion of the area.

A second reason for this assumption is risk considerations by the distribution companies. Many distribution companies are engaged in a process of Integrated Resource Planning, where part of the challenge is to include risk considerations in finding the right portfolio of resources for the long-term plan (Griffith and Sioshansi 2006, Letzelter 2005). These companies sometimes look for a mix of investments based on an "efficient frontier" method to strike the right balance between low cost and low risk in their resource portfolio. Depending on their view of risk, the portfolio could include a wide range of technologies whose average costs are higher than the nominally best choice in the comparison.

Figure 10 shows the market shares of new construction in the first scenario. With the high reserves, there is no need to initiate construction until the year 2008. The wind market share is shown at the bottom of the stack. Wind investors capture around 25% of new construction when construction begins in the year 2008. Their share declines over time, however, as the construction of wind capacity pushes investors to more costly sites. The next segment counts the market share for biomass power plants. They capture around 10% of new construction. These plants use a variety of fuels such as forest residues, agricultural residues and dedicated energy crops such as hybrid poplars grown and harvested on short rotation (Flynn and Ford 2005).

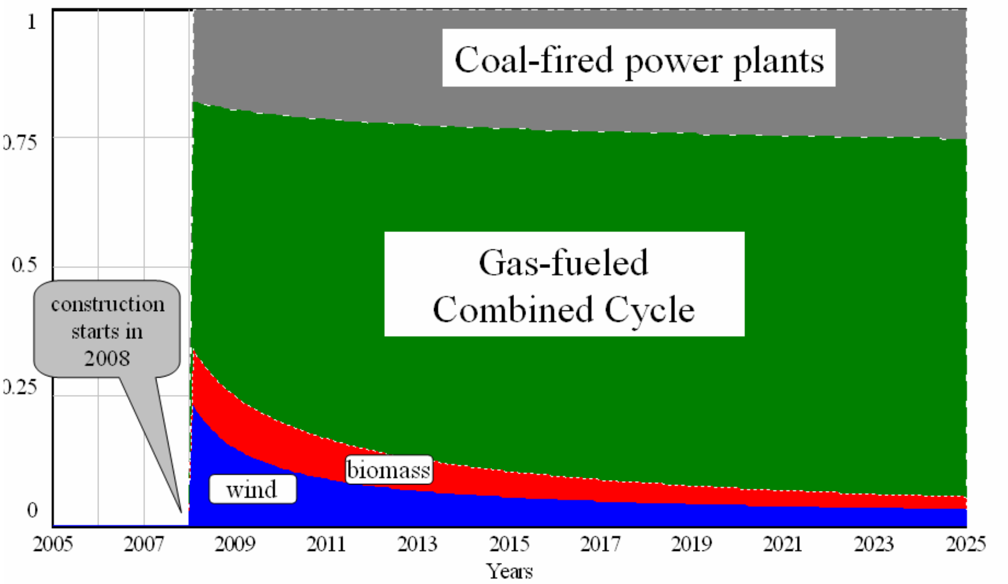


Figure 10. Regional market shares for new construction in the base case simulation.

Gas-fueled combined cycle plants capture the largest share of the market in the base case scenario. If gas prices remain at $5.50 per million BTUs, the CCs would be the lowest cost resource in the Table 1 comparison. Gas CCs also benefit from restrictions on coal construction in California. The final segment at the top of Figure 10 represent coal market share. Coal plants capture around 20% of the regional market in the early years. Their market share grows as the market share for wind and biomass decline over time.

Figure 11 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 an "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 represents the ability of operators to shape the generation toward the middle of the day. (Pumped storage generation is also shaped to contribute in 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 hours in the day.

The thermal units are "market run." Their operation is controlled by the wholesale prices in each hour compared to the units' variable costs. Figure 11 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. Although the user can specify additions to the nuclear capacity, such additions are not part of the base case simulation. (We no not include nuclear construction because we wish to see the impacts of S139 when we adopt conservative assumptions about advanced generating technologies.)

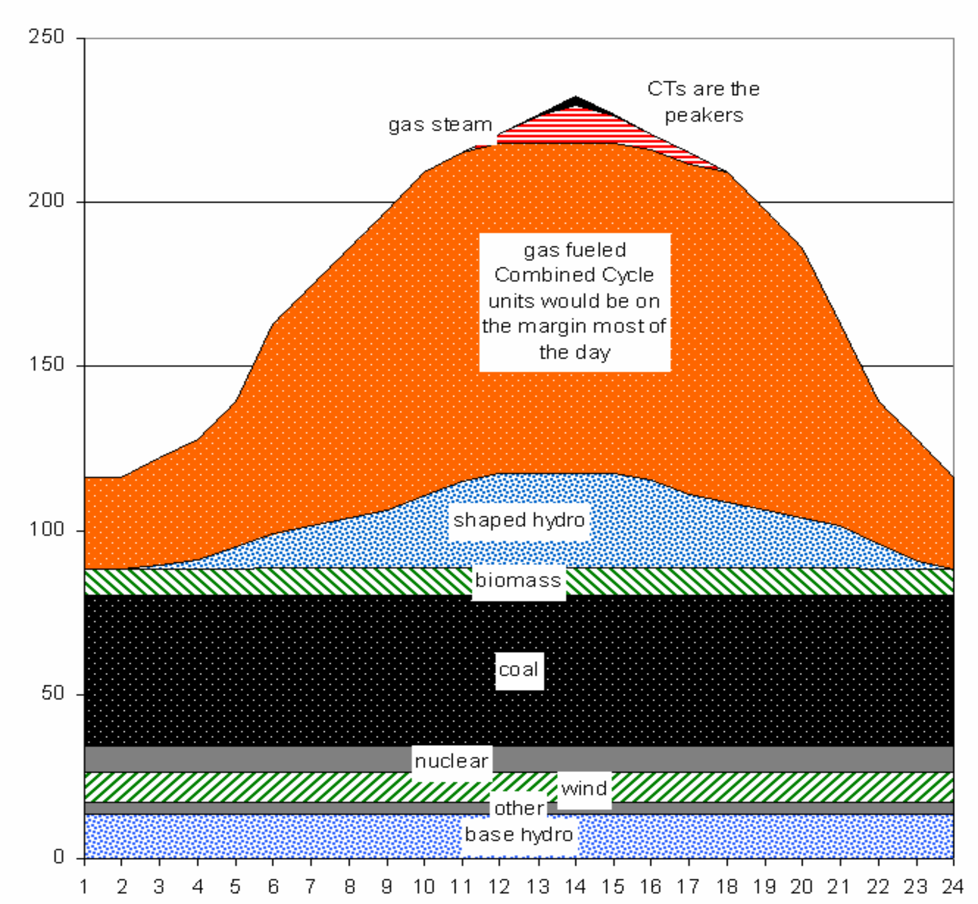


Figure 11. Generation for a typical August day in the final year of the first simulation.

Gas-fired CCs are the most popular choice for new investors in the first scenario. The CC generation is shown in orange in Figure 11. 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 hours in the day. The CCs are on the margin from 1 am to 11 am and again from 6 pm to midnight. During these hours, the wholesale market price will be set by the variable costs of operating the mix of CCs in the west. (We assume that CC owners bid their generating units to the market at their variable costs.) With natural gas priced at $5.50 per million BTU, a highly efficient CC would face a fuel cost around 38 $/MWH and a total, variable cost around 40 $/MWH. These costs explain some of the prices shown previously in Figure 8.

The more expensive gas-fueled generators are shown at the very top of the stack in Figure 11. Gas-fueled steam units operate for around four hours in the day. These units' variable costs range from around 60 to 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. (We ignore withholding in the interest of simplicity and to avoid the distracting, contentious discussion of whether generators actually engage in withholding. Also, it makes sense to ignore withholding because it would probably be counter-productive with the high reserve margins in the simulations shown in this paper.)

Gas-fueled CTs are shown to contribute a small amount of generation around 2 pm, the time of peak demand. The CTs' variable costs range from 68 to 100 $/MWH in the initial simulation. The fact that a few CTs are needed during the peak hour on a summer day explains the peak wholesale price shown near the end of the simulation.

For purposes of this paper, the most important segment in Figure 11 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. For example, a coal plant could release 2,100 lbs of CO2 for each MWH of generation. A gas-fueled plant with the same heat rate would release around 1,200 lbs per MWH. Consequently, coal's contribution to CO2 emissions is much higher than one might think from its contribution to total generation.

Figure 12 shows the CO2 emissions in the first scenario measured in millions of metric tons of Carbon (MMTC) per year. The total emissions vary during the different seasons of each year. Emissions peak in the summer when there is less hydro generation and a much greater dependence on fossil fuels. We keep track of the smoothed value of the total emissions over the year, and this summary variable is shown in black in Figure 12. It grows from 87 MMTC in 2005 to 154 MMTC in the final year of the simulation. The growing carbon emissions is caused by a combination of increased emissions from coal plants and from gas-fire CCs. Emissions from gas steam plants and from gas CTs appear in the summer months, but these are not a major contributor to total emissions.

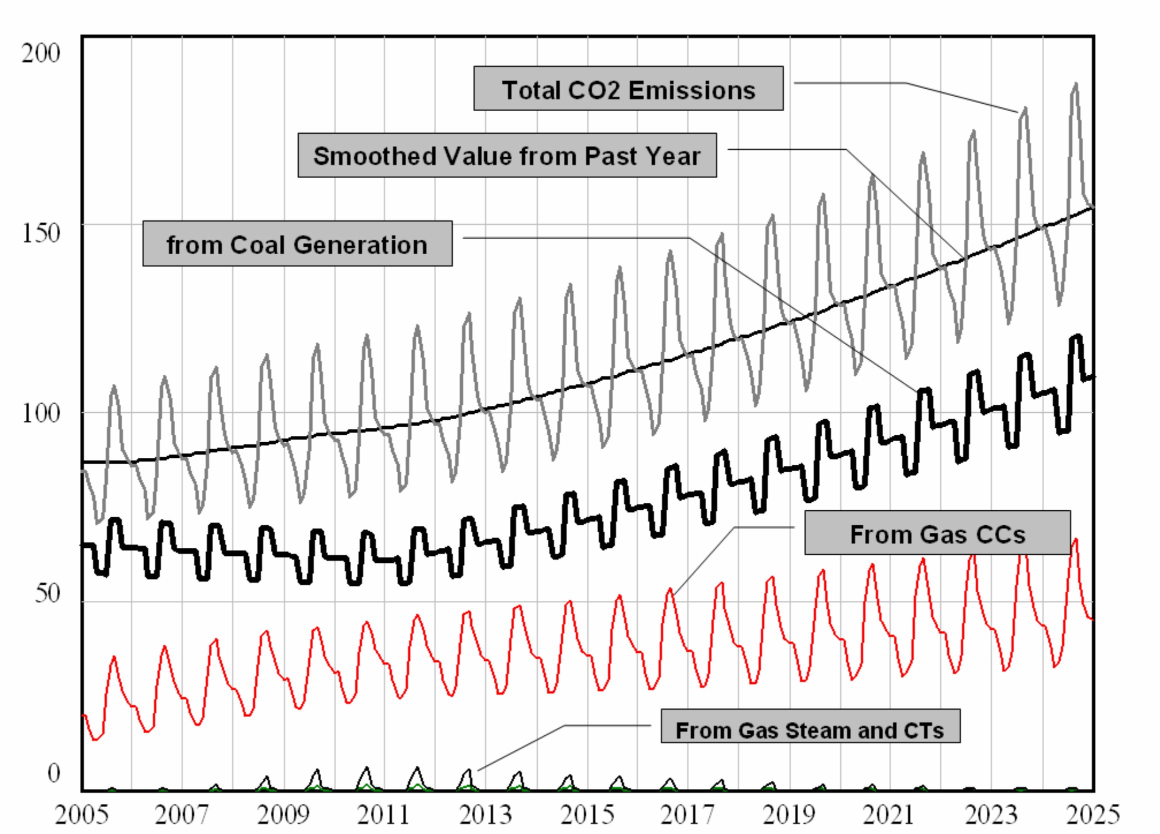


Figure 12. CO2 emissions (MMTC per year) in the first scenario.

Clearly, 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 surprizing since new coal plants capture a relatively modest share of new construction (as shown in Figure 10). The large emissions is because coal is the most carbon intensive fuel for power generation. It is clear from Figure 12 that coal generation must be reduced substantially if the WECC is to achieve dramatic reductions in CO2 emissions. This paper shows that coal generation could be eliminated entirely in a secnario with S139.

Simulated Impact of S139 in the First Scenario

Impact on Power Plant Construction

Figure 13 helps one anticipate the construction market shares that could emerge under S139. This bar graph shows the investor costs that could appear in a simulation with higher and higher prices for carbon allowances. The first bar for each technology corresponds to the costs shown previously in Table I. The remaining bars show the costs that might appear as the price for allowances rise over time. For example, the bars for a gas-fired CC show investor costs with carbon prices ranging from $50 to $250 per MTC. The $100 price is highlighted in Figure 13. With 3.67 pounds of CO2 for every pound of C, this price corresponds to a price of 27 $/MTCO2, a price that would be imposed shortly after the carbon market opens in the year 2010. Figure 13 shows that the full cost of a CC would be 65 $/MWH, but the cost of a coal plant would be over 80 $/MWH. This comparison indicates that coal plants would be far too costly for new investment immediately after the market opening.

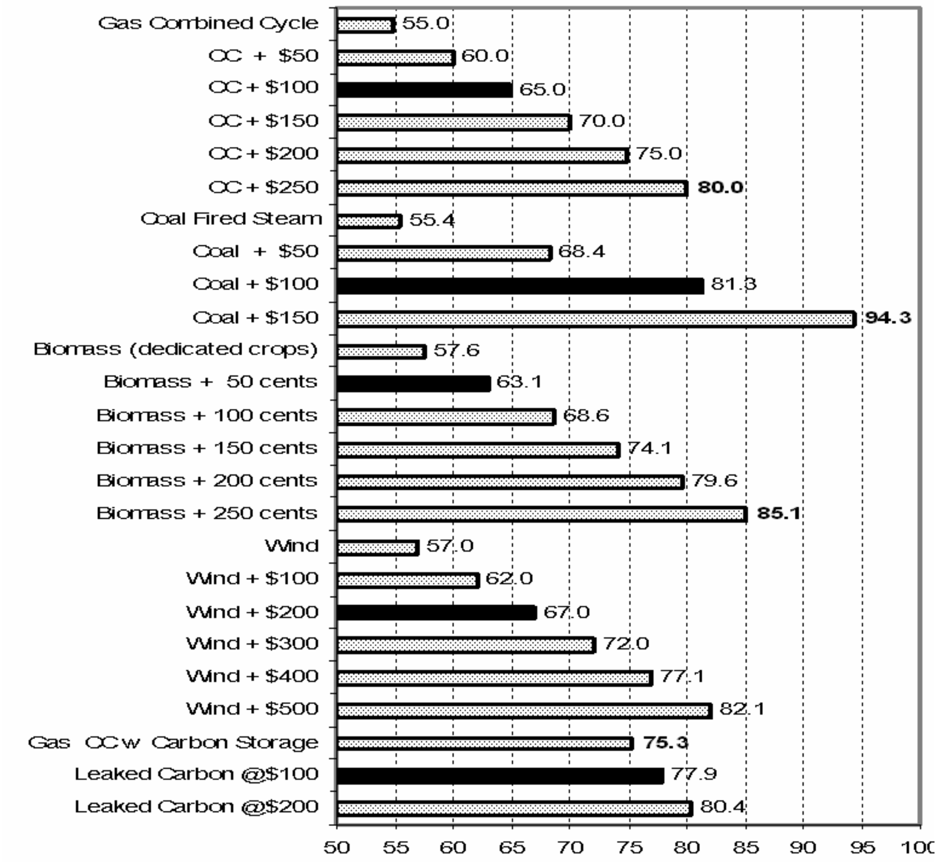


Figure 13. Investor total costs with highlighted bars for a carbon allowance price of 100 $/MTC.

The costs for biomass plants are shown next. We assume that the long-term source of fuel for biomass plants is dedicated energy crops. (An example would be hybrid poplars grown on tree frams with a short harvest rotation.) It is likely that investors will exploit the most attractive sites for tree farms early. Over time, they will be forced to turn to less attractive sites and will face higher costs to harvest and deliver the fuel. The five extra bars in Figure 13 show the investor cost for a biomass plant depending on the additional cost to deliver the biomass to the plant. The highlighted bar shows that biomass capacity would be competitive with CCs if the biomass could be delivered with a 50 cents/million BTU increase in costs.

The wind costs in Figure 13 are arranged according to an increase in construction cost. The wind attributes are explained in a separate paper (Ford 2005) and reported in Table I. The key attribute is the construction cost. The initial construction cost is 1,000 $/kw, so a 1 MW turbine would cost $1 million. To be conservative on wind, we assume that there are no learning effects over time. So the construction cost will not decline with greater investment. Indeed, our assumption points in the opposite direction – we assume that wind construction costs will increase over time as developers turn to sites with higher costs to connect to the transmission grid and to integrate the intermittent wind into the system. These costs have been the subject of several studies. We rely on studies from the National Renewable Energy Laboratory (NREL) where the cost increases are translated into an equivalent increase in the capital cost. When these cost increases are placed in the Figure 13, we see the likely impact of S139. For example, when the carbon price reaches 100 $/MTC, wind capacity would be competitive with CCs even if investors must spend an extra 200 $/kw to develop the wind farm.

The lower portion of Figure 13 is reserved for an advanced generating technology. The final three bars show the total costs for a gas-fired combined cycle unit with the capability for carbon capture and storage. We assume that this technology could become available near the end of the simulation for a total cost of around 75 $/MWH. Figure 13 shows the increase in costs from such a generator if there is some leakage from storage (and the leaked carbon is subject to the carbon allowance prices). Research is currently underway to test different sequestration methods and to verify that the stored carbon is not subject to leakage (IPPC 2005). So, for the base case test of S139, we assume that this technology becomes available around the year 2020 with zero leakage. Figure 13 shows that this technology would be competitive with a regular gas-fueled CC if the carbon allowance price were at 200 $/MTC. This prices corresponds to 54 $/MTCO2. Thus, our assumptions on this advanced generating technology are rather conservative. (For example, the IPPC (2005, p. 10) recently estimated that such systems could “begin to deploy at a significant level” when CO2 prices begin to reach approximately 25-30 $/MTCO2.)

Figure 14 shows the construction market shares in the S139 simulation. As in the base case, there is no need to initiate construction until the year 2008. When construction begins, the market shares are the same as in the base case simulation. However, the market shares change dramatically when the carbon market opens in 2010. The wind market share increases to just over 40%, and the biomass share increases to just under 40%. These renewable resources capture 80% of the market for new construction. Coal is no longer competitive, so gas-fueled CCs capture the remaining 20% of the market.

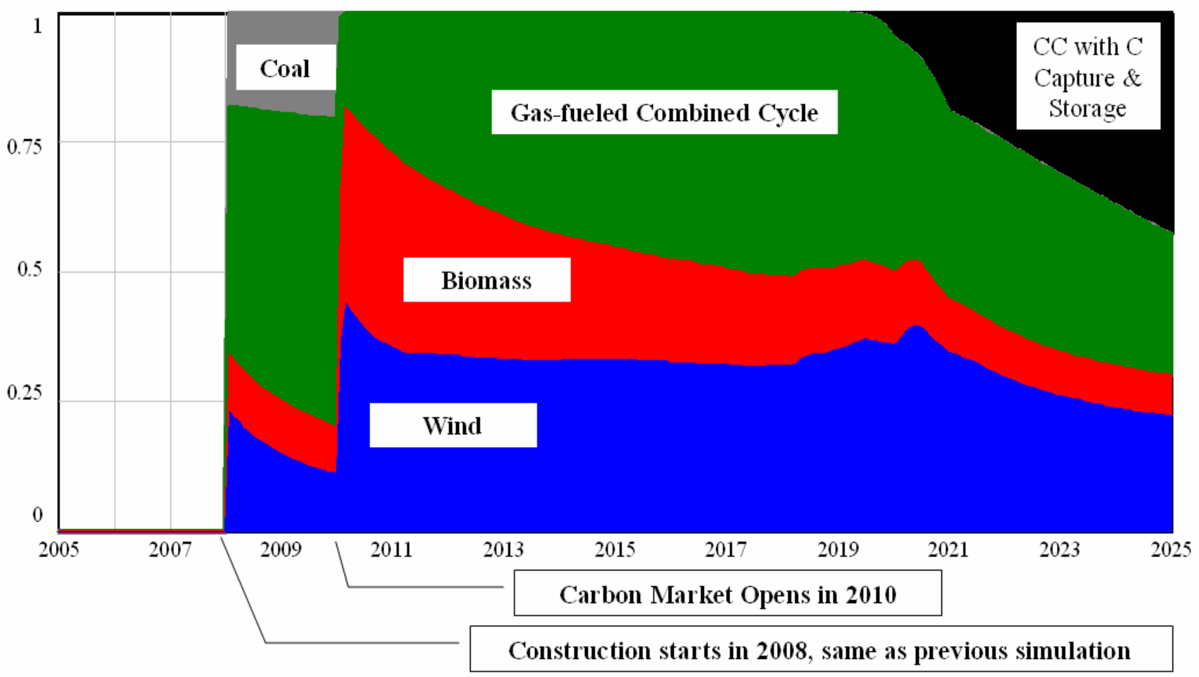


Figure 14. Construction market shares in the S139 case.

The combined market shares for wind and biomass declines from 80% to around 50% during the decade from 2010 to 2020. This decline is caused by the increased costs faced by developers as they turn to less advantageous sites for the wind farms and the tree farms. Even though their costs are increasing over time, these renewable resources are able to maintain a sizeable market share because of the increasing price of carbon allowances. By the year 2020, wind and biomass are still able to capture half of new construction. After 2020, however, their market shares decline due to the appearance of the advanced technology.

The WECC model includes one form of advanced, carbon-neutral generating technology. From the many possible technologies, we selected gas-fueled CCs with carbon capture and sequestration. This particular technology showed the greatest response to S139 in the EIA study (EIA 2003, p. 129). For the purposes of this paper, this technology should be viewed as a "back-stop" technology since there appear to be ample sites for carbon sequestration (Herzog 2005). Consequently, we impose no limits on the construction that might occur if CCs with carbon capture become the most attractive choice late in the simulation. This assumption guarantees that the attributes of this advanced technology could eventually control the post 2025 impacts of S139.

Table II shows the costs of a conventional gas-fueled CC along side of the corresponding costs (EIA 2003, p. 130) for a gas CC with carbon capture and storage. The advanced technology would cost over 80% more to construct. It would also cost more to operate because of the substantial energy requirements to run the capture and storage equipment. For example, if gas were available at $5.50 per million BTUs, the heat rate penalty would translate into an increase of 10 $/MWH in fuel cost. Table II shows a bottom-line cost of 75.3 $/MWH for the advanced technology. (We assume that this technology is able to store the carbon with zero leakage.) Since the technology is still under development, the 75.3 $/MWH cost does not apply until the year 2020. By this time, the CCs with sequestration would win a small share of construction. By 2025, they would capture a third of construction. However, with a 3-year construction time, they would contribute only 2% of generation by the end of the simulation.

Fixed Costs	**Conventional Gas CC**	**Gas CCs C Seq.**
Construction Cost ($/kw)	600	1,100
Fixed Charge Rate (1/year)	0.145	0.145
Annualized Const. Cost ($/kw-yr)	87	159.5
Fixed O&M ($/kw-yr)	10	10
Fixed Transmission ($/kw-yr)	15	15
Total Fixed Costs ($/kw-yr)	112	185
Capacity Factor to convert to $/mwh	0.9	0.9
Levelized Fixed Costs ($/mwh)	14.2	23.4
Variable Costs		
Variable O&M ($/mwh)	2.8	3.8
Cost of fuel ($/million btu)	5.50	5.50
Heat Rate (btu required per kwh)	6,900	8,750
Fuel Cost ($/mwh)	38.0	48.1
Regular Estimate of Variable Costs	**40.8**	**51.9**
Shaping Costs ($/mwh)	0	0
Total Variable Costs with Shaping	**40.8**	**51.9**
Total Levelized Cost ($/mwh)	**55.0**	**75.3**

Table II. Investors' costs for a conventional CC and a CC with carbon capture and sequestration.

Impact on Generation

Figure 15 shows how the generating technologies would be dispatched during a typical August day in the final year of the simulation in the S139 scenario. A comparison with the previous chart shows that S139 would lead to somewhat less demand. The demand is around 9% lower due to the consumers' reaction to the higher retail rates. (In a S139 scenario, most 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 conservative position on S139.)

There is no additional investment in hydro capacity in the S139 scenario. Furthermore, 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 greater investment in nuclear capacity with S139. Given the many uncertainties on nuclear plant performance and on waste disposal, we decided to simulate S139 without any additional nuclear capacity. This assumption maintains the conservative approach to estimating the impacts of S139.

Fig. 15 shows large contributions from wind and biomass generation. By the end of the simulation, wind provides around 25% of total generation; biomass provides around 12% of total generation. In contrast, the CCs with carbon capture and storage technology provide only 2% of the WECC generation in the final year of the simulation.

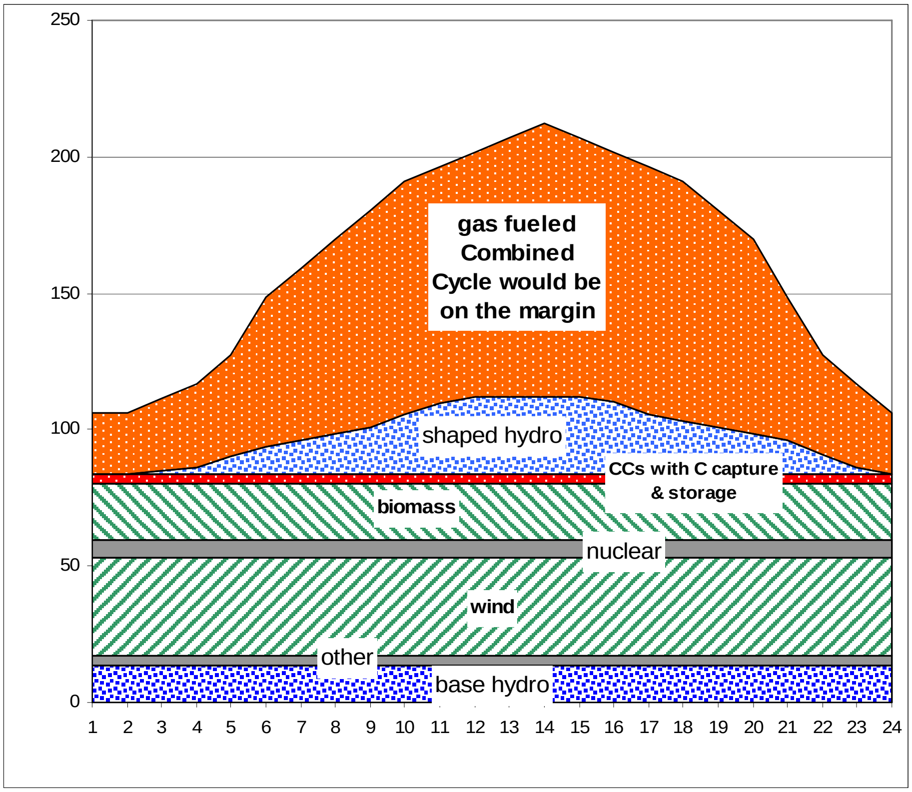


Figure 15. Generation for a typical August day in the final year of the S139 simulation.

Figure 15 shows that coal generation would be completely eliminated by the end of the simulation. Coal generation was highlighted in black in the previous chart of a 24-hour 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 under S139. 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 complete 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 envisious 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.

Impact on Emissions and Retail Rates

Figure 16 shows the simulated impact of S139 on carbon emissions (measured in MMT/year). We show the smoothed value of the annual emissions from each year. The base case simulation shows CO2 emissions growing to 154 MMT/year. The growth in CO2 emissions is halted a few years after the market opens in 2010. By 2014, CO2 emissions are on a downward trajectory. S139 is projected to cut emissions by over 75% by the end of the simulation.

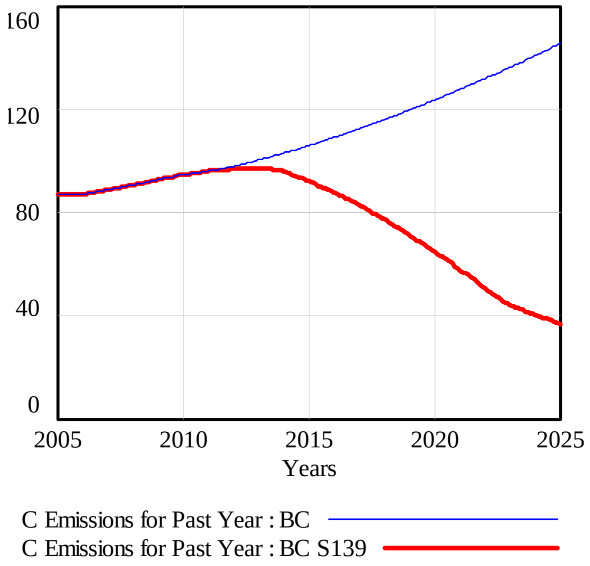


Figure 16. Simulated impact on the carbon emissions (in MMTC/yr) in the WECC

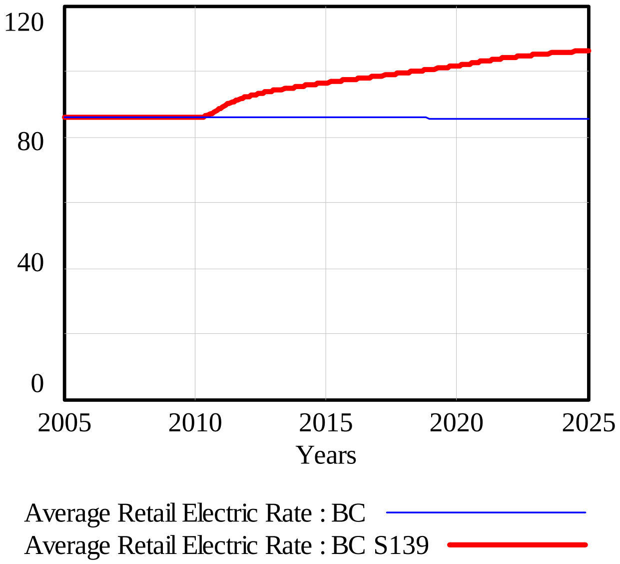


Figure 17. Simulated impact on the average retail rate (in $/MWH) in the WECC.

Figure 17 shows the simulated impact on the average retail electric rate. The base case electric rate is constant at 86 $/MWH. The generation portion of the retail rate is 56 $/MWH; transmission and distribution and other expenses amount to 30 $/MWH. The generation component is based on the wholesale price of electric energy plus a premium payment to induce construction of new power plants to keep pace with demand growth. The retail rate is driven up in the S139 scenario by a combination of higher wholesale prices and the higher costs faced by new investors. The average retail rate in the year 2025 is 106 $/MWH, roughly 23% higher than in the base case simulation. The overall impact on the electricity consumer in the west is a 23% increase in retail electric rates, half the impact estimated by EIA for the nation as a whole. One reason for the reduced impact to the retail customer in the west is that the west does not rely as extensively on coal. Coal is the most carbon-intensive fuel, and a carbon allowance price has the greatest impact on the variable cost of coal-fired power plants which operate on the margin in some regions. In the west, however, gas-fired generators are usually on the margin, so western wholesale prices experience a smaller impact from the carbon allowance prices expected under S139.

Wind and biomass construction also contribute to the relatively small impact on retail consumers in the west. Wind construction is especially important in the simulations shown here. With a combination of a carbon allowance market and a production tax credit, the western system could see wind providing 25% of total generation. This would match the contributions envisioned by the European countries that have made national commitments to wind.

It is important to note that the costs of expanding wind generation and biomass generation in the west will be substantial. It is equally important to note that these costs are included in the simulations shown here. The papers take 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 in biomass capacity. The simulations teach us that carbon market will allow wind and biomass investors to pay these extra costs. The extra costs appear in the long-term contracts signed with the distribution companies, and the distribution companies pass the higher costs to the retail consumer. When the combination of factors is simulated, the long-term impact is a 23% increase in the average retail electricity rate in the west.

Simulating a Scenario with Slower Growth and a Shift to Coal Plants in the East

The previous tests 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 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 in the EIA study of S139 (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.

Investor’s Choice of Power Plant Construction

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 California, Oregon and Washington (Frontier Line 2005, Radford 2006, 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. Figure 18 shows the construction market shares in the new scenario. 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.

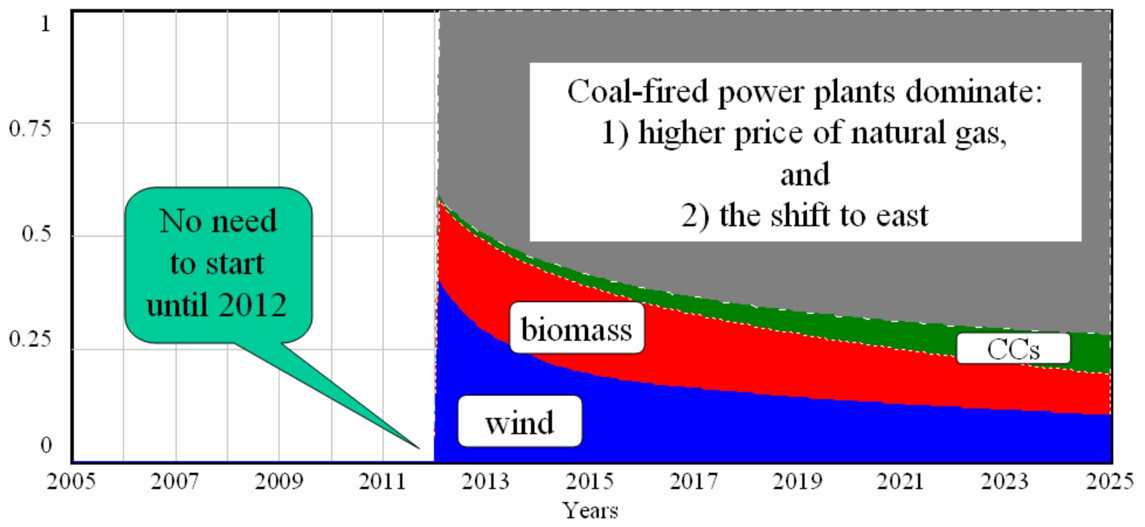


Figure 18. Construction market shares in the second scenario.

Impact of S139 in the Second Scenario

Figure 19 shows the simulated impact of S139 on CO2 emissions in the new scenario. The new base case (NBC) shows somewhat slower growth in emissions. This may surprise some readers since the new case includes a major increase in the coal-plants' market share of new construction. But the new case requires less total construction because of the slower growth in demand. By the year 2025, the total emissions are somewhat less than in the first scenario. Figure 19 shows the S139 emissions by the thicker curve (in red). 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 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.

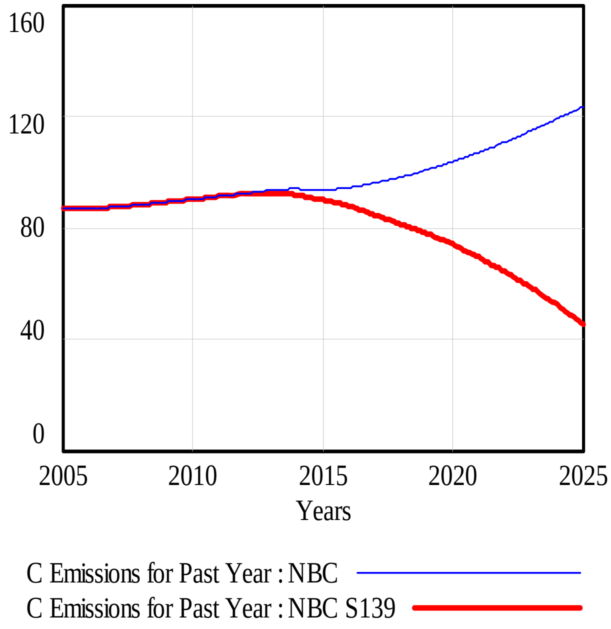


Figure 19. Simulated impact on carbon emissions (in MMTC/yr) in the second scenario.

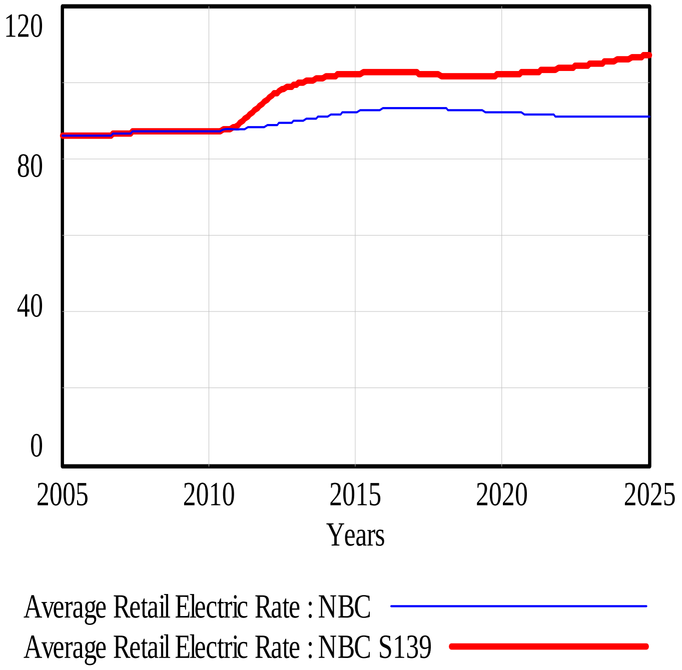


Figure 20. Simulated impact on the average retail rate (in $/MWH) in the second scenario .

Figure 20 shows the average retail electric rates in the second scenario. The thin, blue curve in Figure 20 shows that the average electric rate would be higher under the new assumptions. The primary reason for the higher rate is the higher cost of natural gas. The thick, red curve in Figure 20 shows the average retail rate due to S139. The comparison shows that rates increase within five years after the carbon allowance market opens in 2010. The higher rates are needed to cover both the higher costs of wholesale electricity and the higher costs of the mix of power plants under construction. By the year 2025, the average retail electric rate climbs to 107 $/MWH under S139. The simulation indicates that S139 would lead to an average of 18% higher retail rates to electricity consumers in the western USA and Canada.

Summary of Results

Figure 21 summarizes the long-term impacts of S139. 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 505/50 line. The base case results have been described in the most 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 base case 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 even more encouraging – the base case simulation shows that the rate increase would be only half as large as the EIA projected for the entire nation.

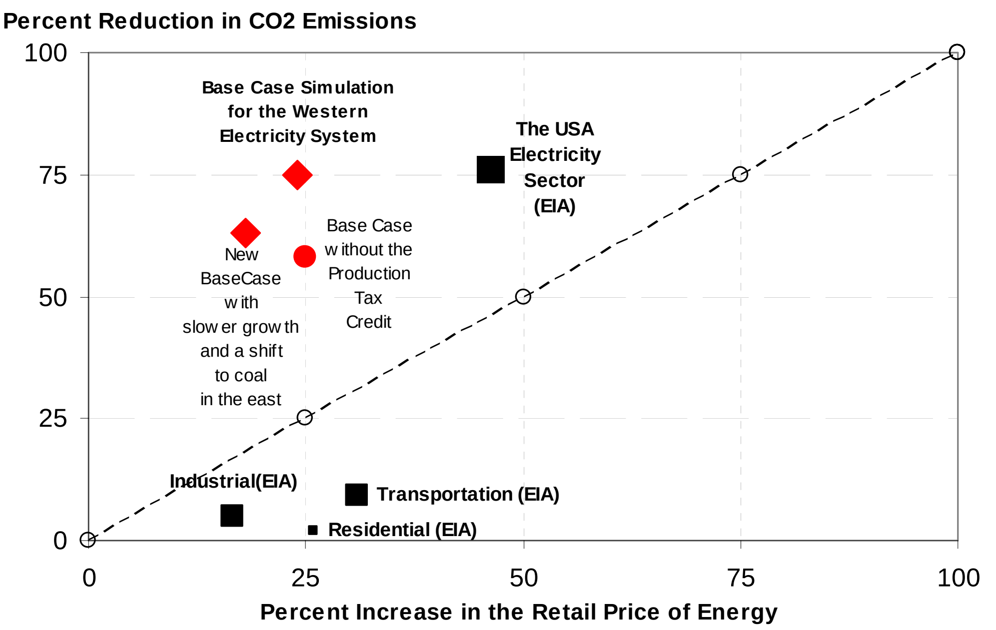


Figure 21. Summary results for the simulations reported in this paper.

We have conducted numerous tests to learn if the simulated impacts of S139 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, andall tests conducted to date show results that lie well above the 50/50 line in Fig. 13.

One of the more important inputs to the model is the renewable generators production tax credit (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, and the Western Governors' Association has made extension of the PTC a top priority. At the time of the EIA analysis of S139, 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 we decided to leave it in effect in both the base case and the S139 simulations. (Sterzinger (2006) explains the rational for making the PTC permanent.) To learn the importance of the PTC, we repeated the simulation without the PTC. This new result is depicted by the red circle in the summary diagram. The position of the red circle reveals that the removal of the production tax credit 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 lay well above the 50/50 line indicating the electricity sector could still lead the way in reducing carbon emissions.

The third result in Figure 21 summarized 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 electricty 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 lie well above the 50/50 line, providing further confirmation that the western electricity system would lead the way in reducing carbon emissions.

Implications for the Creation of a National Carbon Market

The national impacts of S139 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 envisioned in S139 would elicit major reduction 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 USA 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%. The retail impact on western consumers could be limited to around 23%, half the impact expected for the nation as a whole. 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 in the S139 simulation. Investors turn to CCs with carbon capture around the year 2020. With a three-year lag for construction, the new technology contributes only 2% to total generation by the year 2025. 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. Indeed, those interested in promoting the development of such technologies might argue for prompt implementation of a carbon market. Carbon allowance prices climbing from \$22 to \$60 per MTCO2 (Fig. 3) could generate substantial interest in the development of these technologies.

Despite the seriousness of the greenhouse gas problem, federal initiatives to develop a mandatory market for carbon allowances have stalled. In the absence of federal action, various states are taking the initiative to curb GHG. The state and regional initiatives are summarized in a separate conference paper (Ford 2006).

Ideas for Further Research

Several ideas for further research are described in the separate conference paper (ford 2006). One important area is relevant to both the USA and to Brazil. It involves the massive land needs to support biomass production. The simulations shown here indicate a huge investment in biomass-fueled power plants if a carbon market is adopted in the USA. In the first scenario, for example, there is over 24 GW of biomass capacity by the year 2025, and the power plants would provide 12% of total generation.

The land requirement to fuel these plants depends on the type of crops, the harvesting rotation period and the heat rate of the power plant. These factors have been examined through system dynamics simulation by Flynn and Ford (2005). A portion of their model shown in Figure 22. The model allows for exerimentation with the rotation period of fast-growing crops (ie, hybrid poplars) so that carbon benefits are maximized. The model also shows the land requirements to provide dedicated fules for power generation. Using round numbers, it is useful to assume that a million hectares of land would be needed to fuel a GW of biomass capacity. The land requirement in the S139 scenario could be around 24 million hectares in the western USA and Canada devoted to dedicated crops such as hybrid poplars.

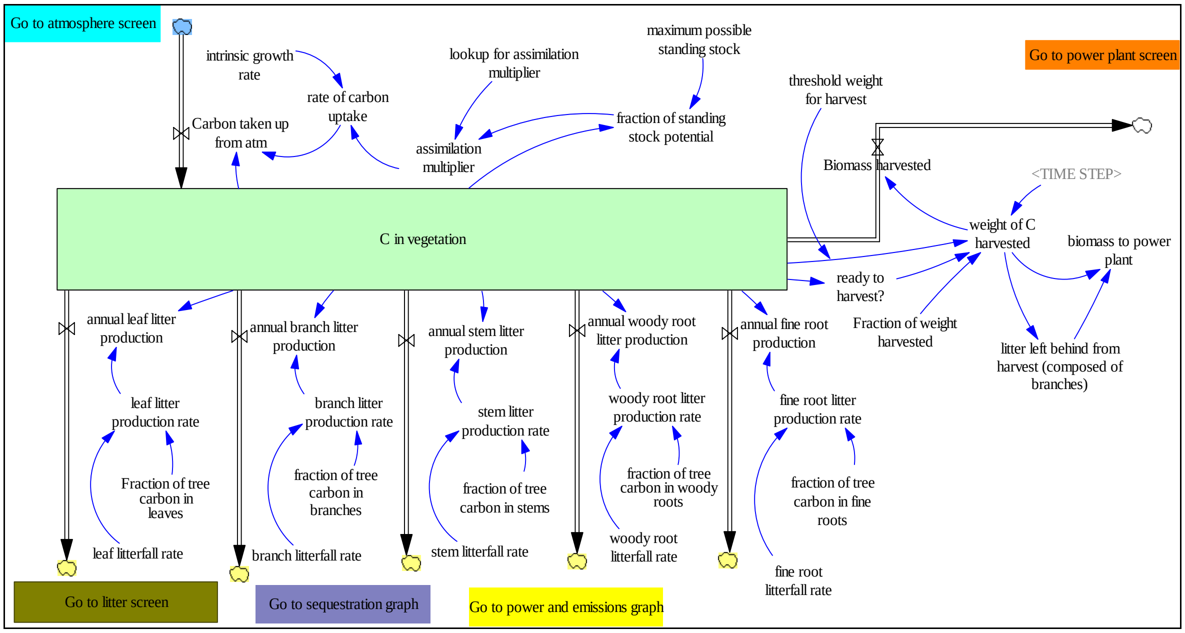


Figure 22. The “vegetation view” of a model to simulate carbon cycling in crops dedicated to power production.

It would useful to expand the model of the western electricity system to study these land use implications in more detail. It would also be useful to expand the scope of the model to simulate the land needs associated with the growing production of biofuels. The amount of biomass production could be staggering; one study envisions a “billion-ton” annual supply (ORNL 2005), enough to replace 30% of petroleum use by 2020 and to fuel 5% of the nation’s generating capacity by 2020. The combined land needs to produce fuels for both vehicles and power plants would be even larger.

These land use implications are well suited to examination by system dynamics simulation. This topic is important to the USA and especially important to Brazil, the world’s leader in biofuels production (Herrera 2006).

Acronyms Used in the Paper

ATC	Available Transmission Capability
CAISO	California Independent System Operator
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
DC	Direct Current
DC OPF	Direct Current Optimal Power Flow
DEWI	Deutsches Windenergie Institut (German wind energy institute)
DLL	Dynamic Link Library
EIA	Energy Information Administration
GDP	Gross Domestic Product
GHG	Greenhouse Gas
LMP	Locational Marginal Price
IOU	Investor Owned Utility
IPP	Intermountain Power Project
NREL	National Renewable Energy Laboratory
NWPP	Northwest Power Pool
OPF	Optimal Power Flow
RGGI	Regional Greenhouse Gas Initiative
RMPA	Rocky Mountain Power Area
S139	Senate Bill 139, the Climate Stewardship Act of 2003
WECC	Western Electricity Coordinating Council
WSU	Washington State University

Units Used in the Paper

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 1,000 MW
kw	kilowatt, a measure of capacity; a kw is 1,000 watts
kwh	kilowatt-hour, a measure of electric energy
mill	there are 1,000 mills in a $
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 1,000 kw
MT	metric ton, which is 1,000 kilograms or 2,205 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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