Simulating the Impact of a Carbon Market on the Electricity System in the Western U.S.A.

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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. The simulations indicate that a carbon market could lead to dramatic reductions in carbon emissions over the next two decades. 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. The paper concludes with some implications of these results to state and national policy makers.

This analysis is the first major application of a new approach to computer modeling of large-scale power systems. The approach is an interdisciplinary combination of system dynamics and engineering methods. This approach has been implemented in a model of the WECC, the Western Electricity Coordinating Council. The methods and assumptions of the WECC model are explained in the appendicies to the paper.

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

Contents

1. Purpose and Organization of the Paper

This paper describes the simulated impact of a market for carbon allowances in the power system in the western United States. The simulations are presented as the first major test of a new approach to modeling of large scale power systems. The approach is an interdisciplinary combination of system dynamics and engineering:

- system dynamics methods are used to represent the feedback relationships which govern the long-term evolution of the system, while

- engineering methods are used to calculate the short-term prices and power flows subject to the physical limits of the transmission network.

The interdisciplinary approach has been developed over the past several years in research for the National Science Foundation (NSF). The new model has been implemented with data from the western states and provinces that belong to the Western Electricity Coordination Council (WECC). A previous paper describes the methodological results of interest to the NSF (Dimitrovski 2005). This paper describes results of interest to policy makers and energy analysts engaged in the debate over carbon markets.

The paper begins with background on the problem of carbon emissions and the potential for reducing these emissions through a market for carbon allowances. A carbon market has been proposed in the USA by Senate Bill 139, The Climate Stewardship Act of 2003. The paper summarizes the key findings from a study of the S139 impact on the nation's electricity sector. The question for this paper is whether similar results could be achieved in the WECC.

The simulation analysis begins with a description of a 20-year simulation in a scenario with rapid growth in demand and with new construction dominated by gas-fueled combined cycle (CC) power plants. A second scenario is presented with slower growth in demand and with new construction dominated by coal-fired power plants. These scenarios show dramatically different views of the future generation, transmission and CO2 emissions. The impact of S139 is simulated in both of these scenarios by setting the carbon allowance price to follow the trajectory projected in a study by the Energy Information Administration (EIA).

The simulation results are extremely encouraging. They show that the WECC could achieve dramatic reductions in CO2 emissions under both scenarios. The large reductions could be achieved with only half the increase in electric rates that have been predicted for the nation as a whole. Renewable generators play a crucial role in cutting emissions and limiting the rate impacts. Generation from wind and biomass grows dramatically in the simulations with a carbon market, while coal generation would be phased out. Generation from advanced technologies for carbon sequestration are not required for the western electricity sector to achieve the dramatic reductions in CO2 emissions.

These simulation results are important to the debate over cap and trade markets for carbon emissions. The paper concludes with implications for policy makers at both the national and state level.

2. Introduction

The accumulation of greenhouse gas (GHG) emissions in the atmosphere is arguably the most serious environmental threat of our time. 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:

1. *greenhouse gases accumulating in the atmosphere are causing average temperatures to rise at a rate outside the range of natural variability and are posing a substantial risk of rising sea-levels, altered patterns of atmospheric and oceanic circulation, and increased frequency and severity of floods and droughts;*

2. *there is a growing scientific consensus that human activity is a substantial cause of greenhouse gas accumulation in the atmosphere; and*

3. *mandatory steps will be required 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). 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. In 2001, the energy related carbon emissions in the US accounted for 24% of the world’s total (EIA 2003, p. 36).

Figures 1 and 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 is depicted in the middle of the diagram. 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 is depicted at the top of the diagram. 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.

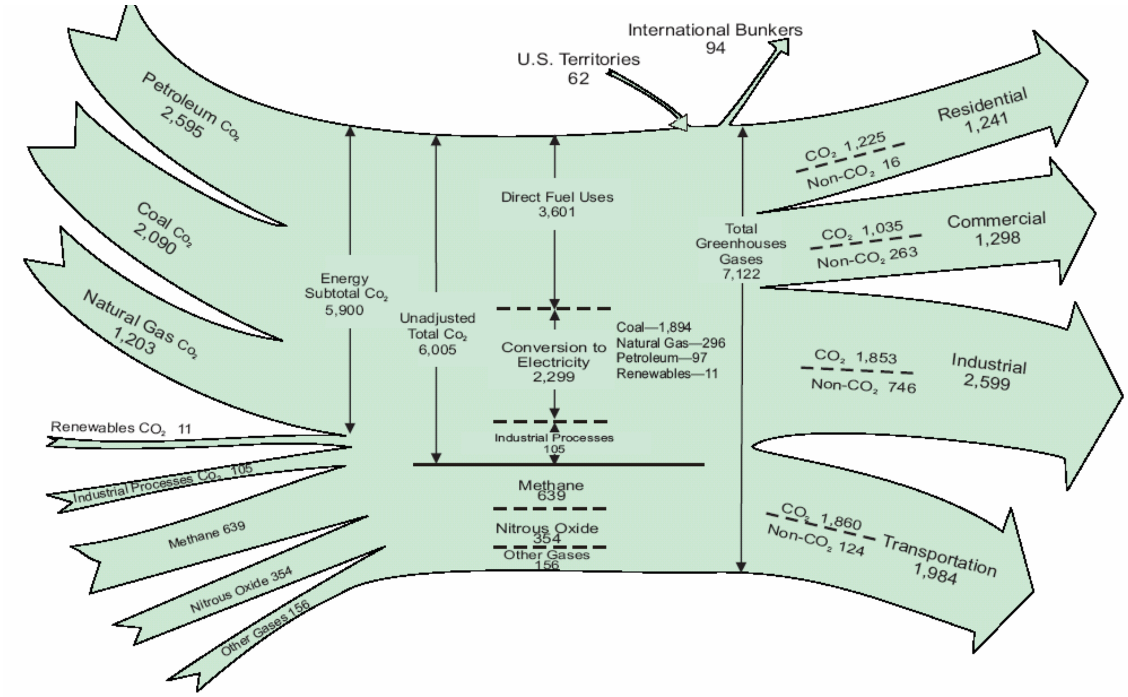

Figure 1. Greenhouse gas emissions in the USA in the year 2004, measured in million metric tons of CO2 equivalent (MMTCO2). Data and diagram from the EIA (2005).

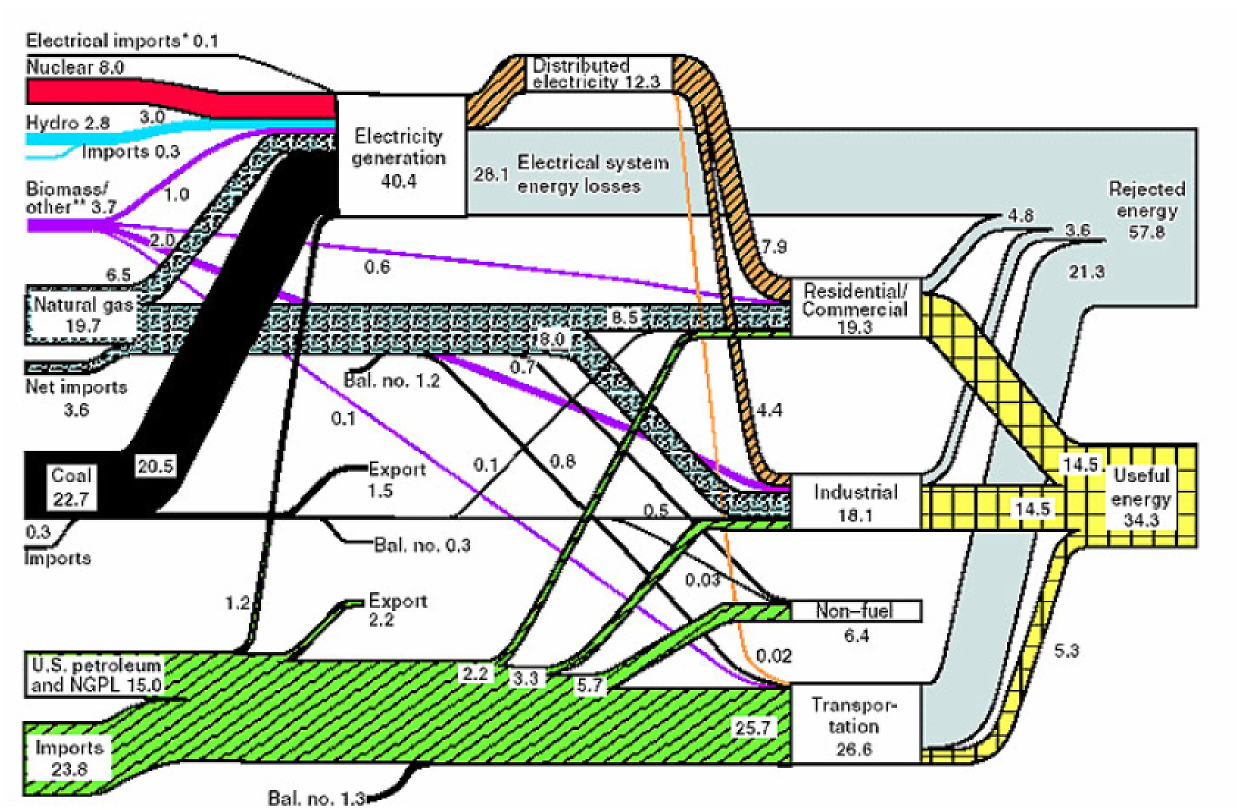

Figure 2. Annual energy flows in the USA in the year 2000, measured in Quadrillion BTUs. (Data from the EIA (2000); diagram from the Lawrence Livermore National Laboratory.)

3. The Climate Stewardship Act

In January of 2003, Senators McCain and Lieberman introduced Senate Bill 139 (S139), the Climate Stewardship Act. It 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 2010 until 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. (With 3.67 tons of CO2 for every ton of C, the starting value in Figure 3 is quite close to the electricity sector emissions shown in Figure 2). By 2025, electricity sector emissions would reach 868 MMTC, 40% higher than in the year 2000.

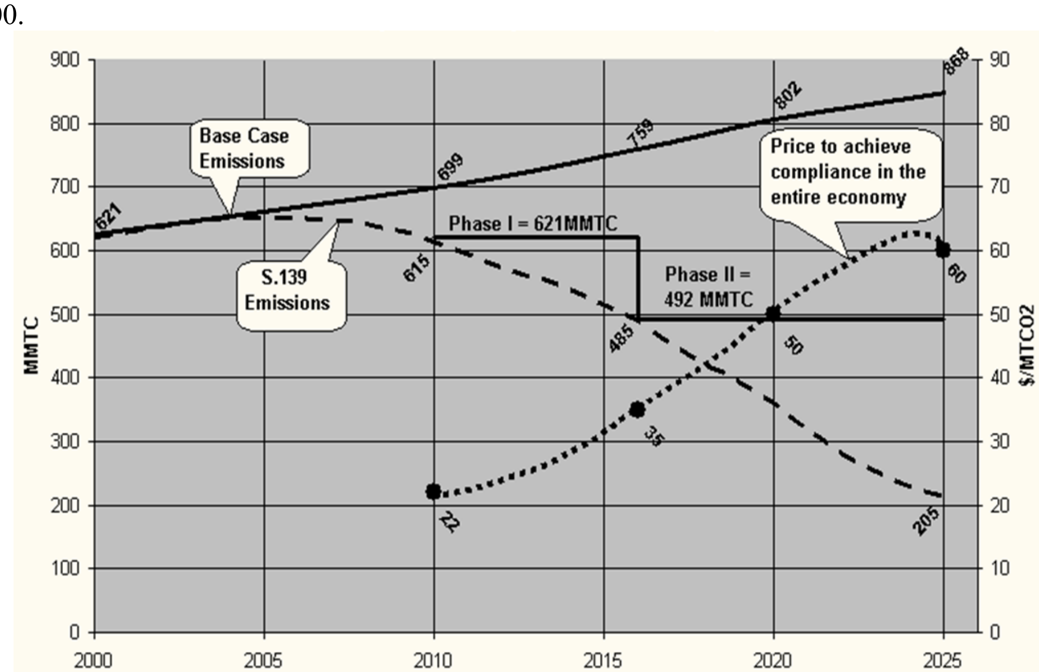

Figure 3. Summary of the EIA analysis of the nation's electricity sector response to S139.

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.

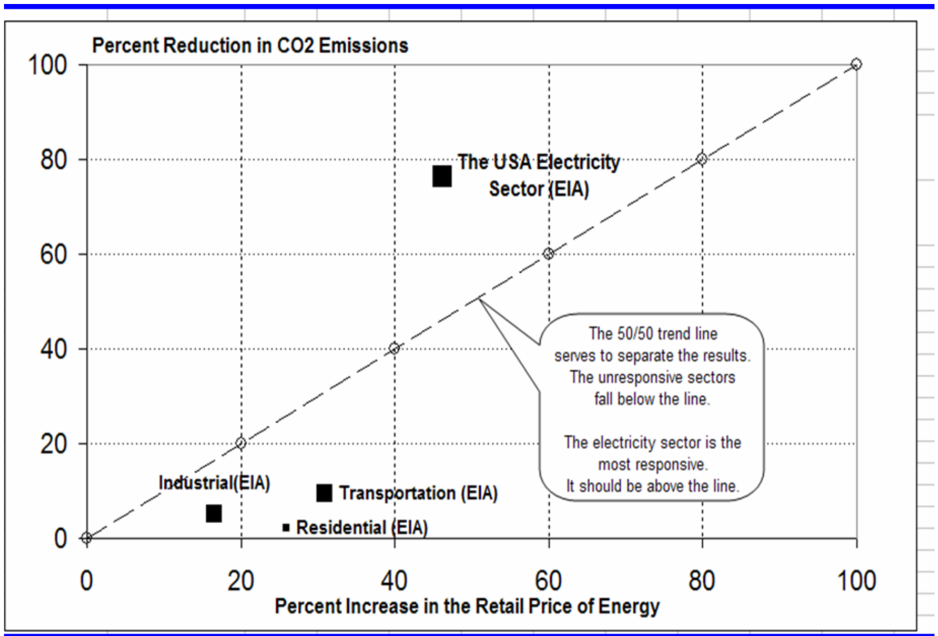

Figure 4. Summary of the EIA estimates of long-term impact of S139.

4. 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 Govennors' 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.

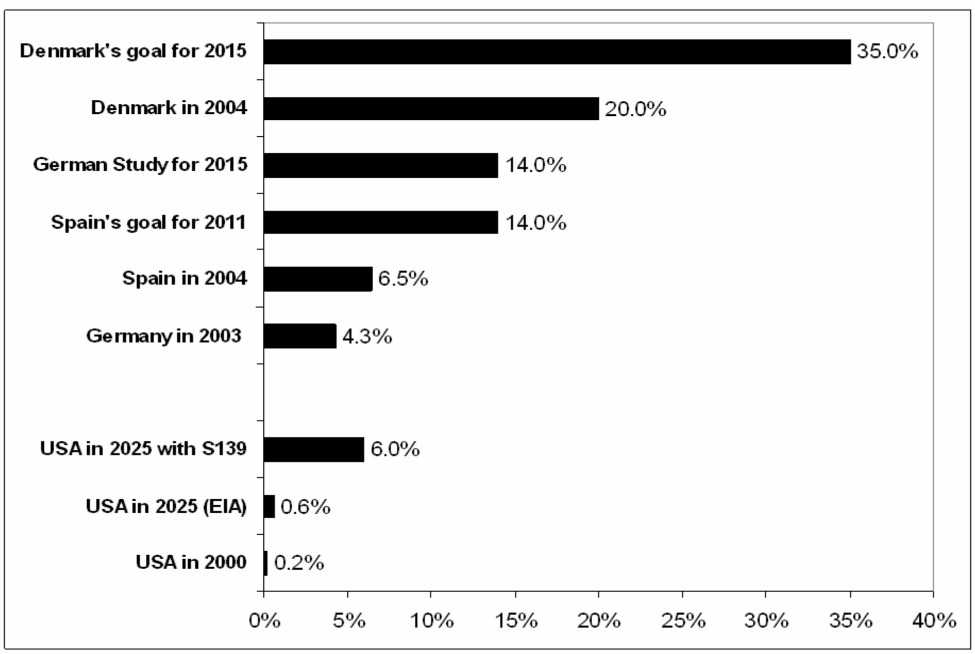

Figure 5. Fractions of electricity generation from wind.

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

5. The WSU Model of the WECC

Figure 6 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. 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 the appendicies.

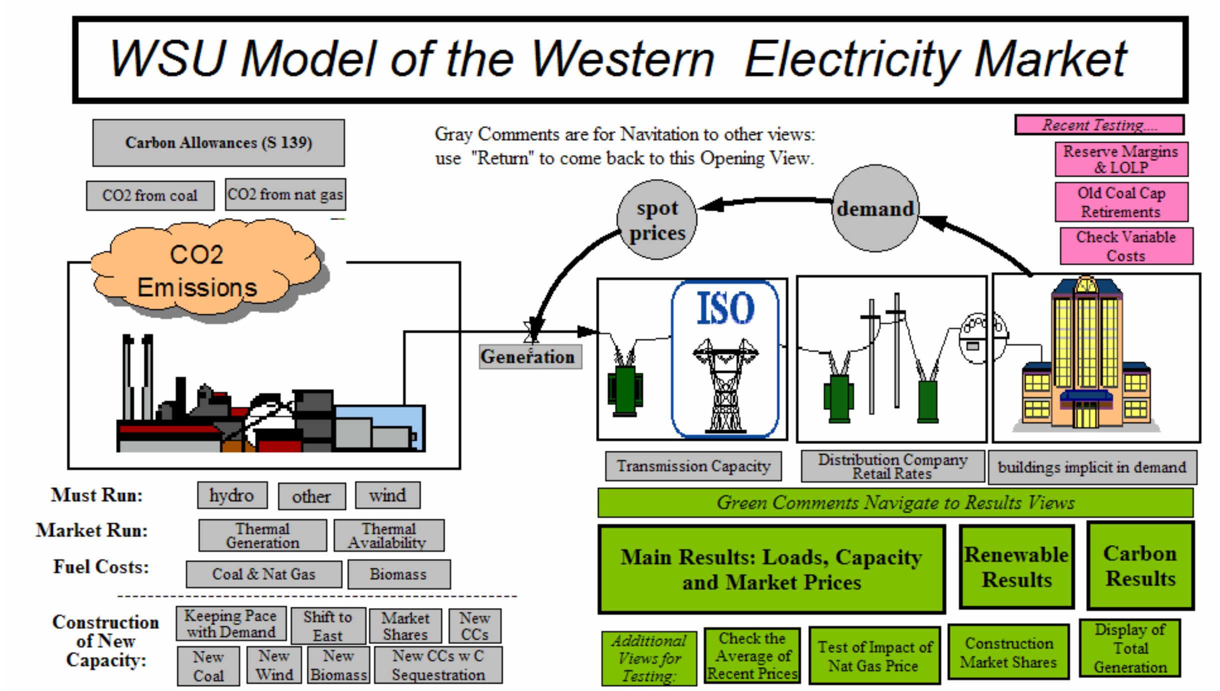

Figure 6. Opening view of the model.

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 scenarios provide an internally consistent view of how the western markets could evolve over a twenty year interval. 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. We then simulate the system to the year 2025 to match the time horizon used in the EIA study. The model operates with time in months, and we simulate conditions for 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.

6. Simulating a 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. The peak load reaches 233 GW by the final year.

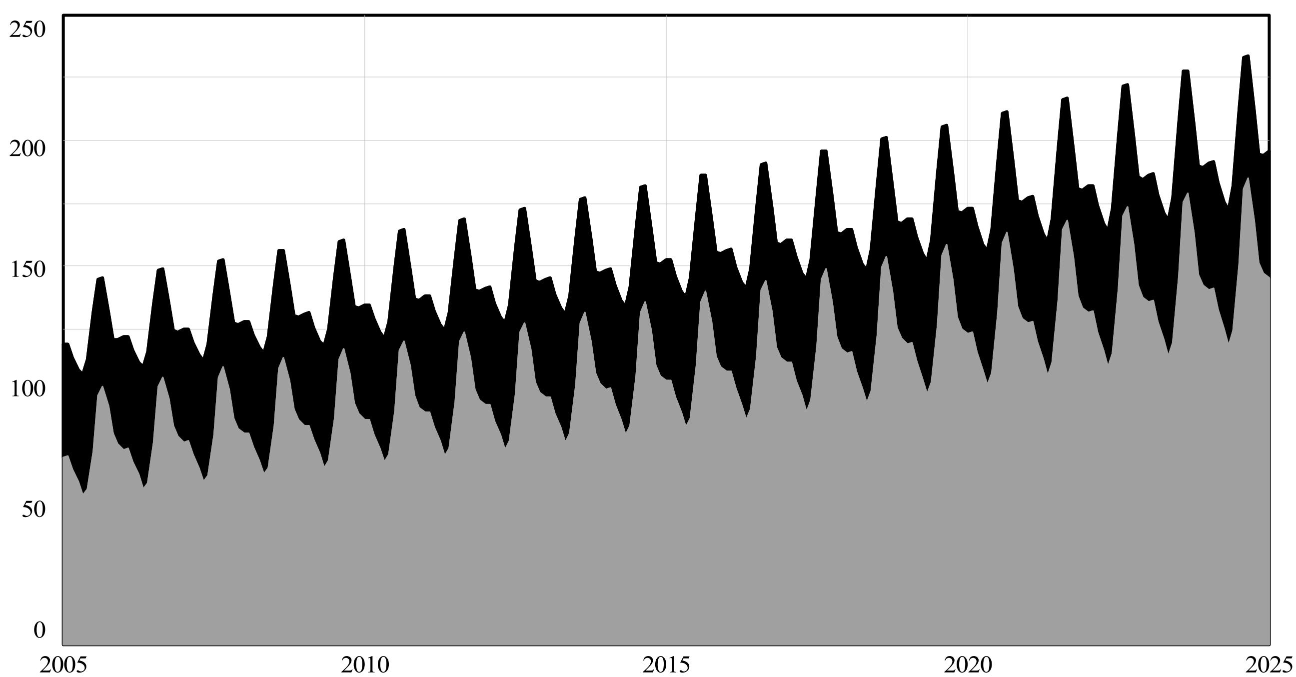

Figure 7. Peak Loads in the first scenario (in GW).
The peak load met by must-run generation is in black. The peak load met by market generation is in gray.

Figure 7 shows that the peak loads are satisfied by a combination of "must run" and "market run" generation. Must-run generation is shown in black at the top of the graph. Market-run generation is in gray at the bottom of the graph. 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. Figure 8 shows that 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. The average daily price is around 44 $/MWH by the end of the simulation._

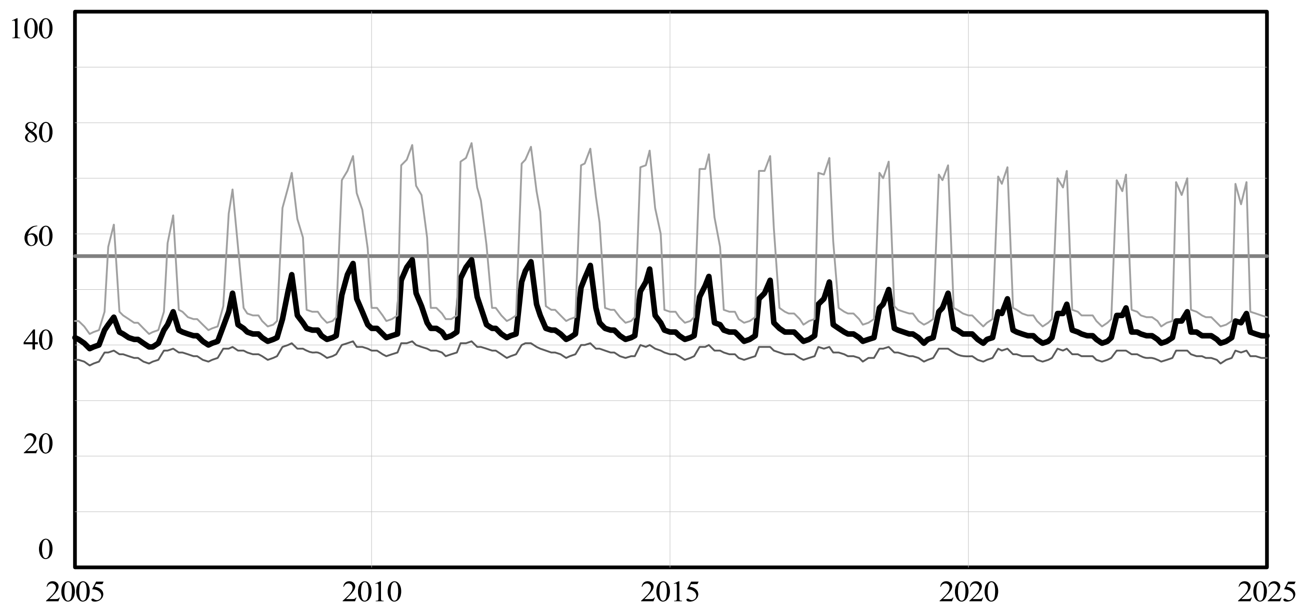

Figure 8. Wholesale prices ($/MWH) for electric energy in the first scenario.
The peak price is in light gray; off-peak price in dark gray; average daily price in black.
The investor's full cost of building new capacity in one of the areas is the flat, gray line.

Figure 8 puts the average daily prices in perspective by showing the weighted average cost of investing in new generation. Investors building would face an average cost around 56 $/MWH. With base case assumptions, this cost is essentially constant 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 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 matches current WECC loads and resources, as described by McCollough (2005).

Figure 9 shows the loads and resources in the simulated spot market for thermal generation. The top curve shows the total thermal generating capacity that bids into this market. 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.

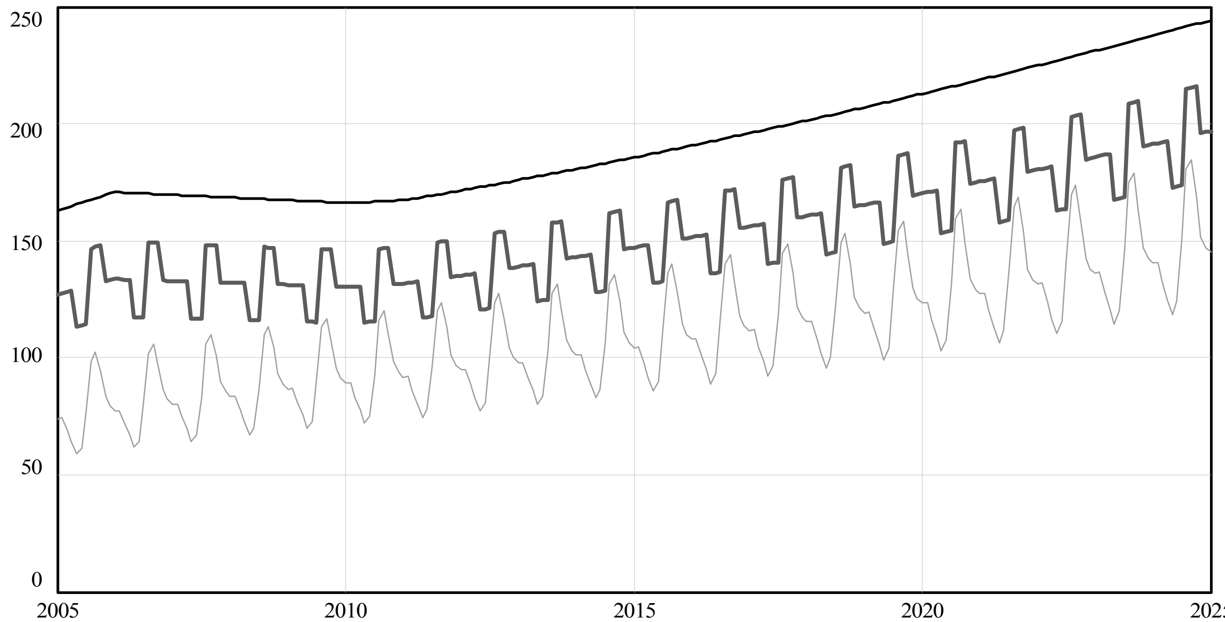

Figure 9. Peak loads (GW) to be served by the market for thermal generation in the first scenario. The total thermal capacity is the top curve. Total thermal capacity available is in dark gray. The peak load to be served by the market is the lower curve.

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. We return to this topic in the final appendix to the paper.) 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).

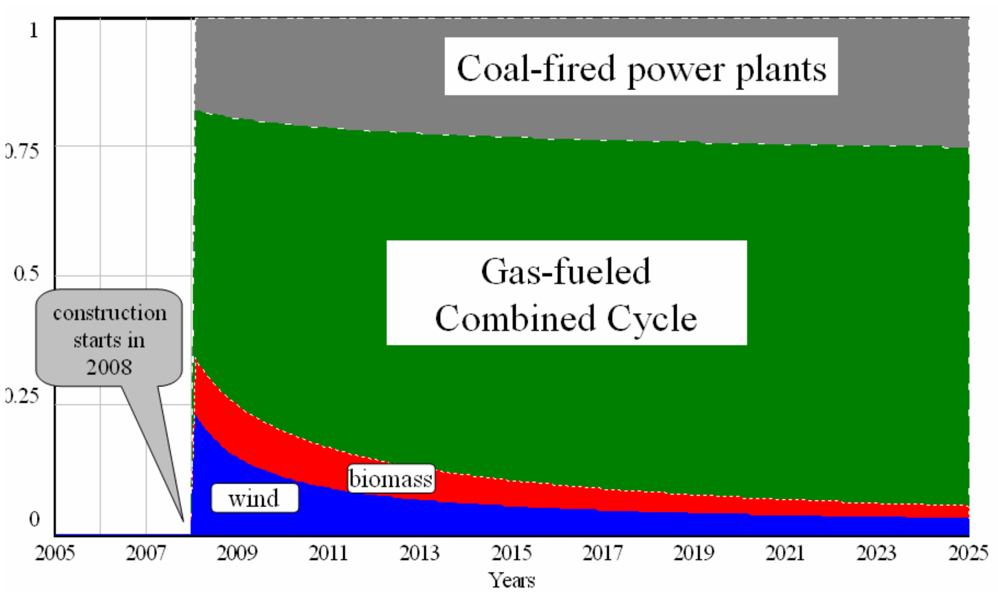

Figure 10. Regional market shares for new construction in the base case simulation.

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.)

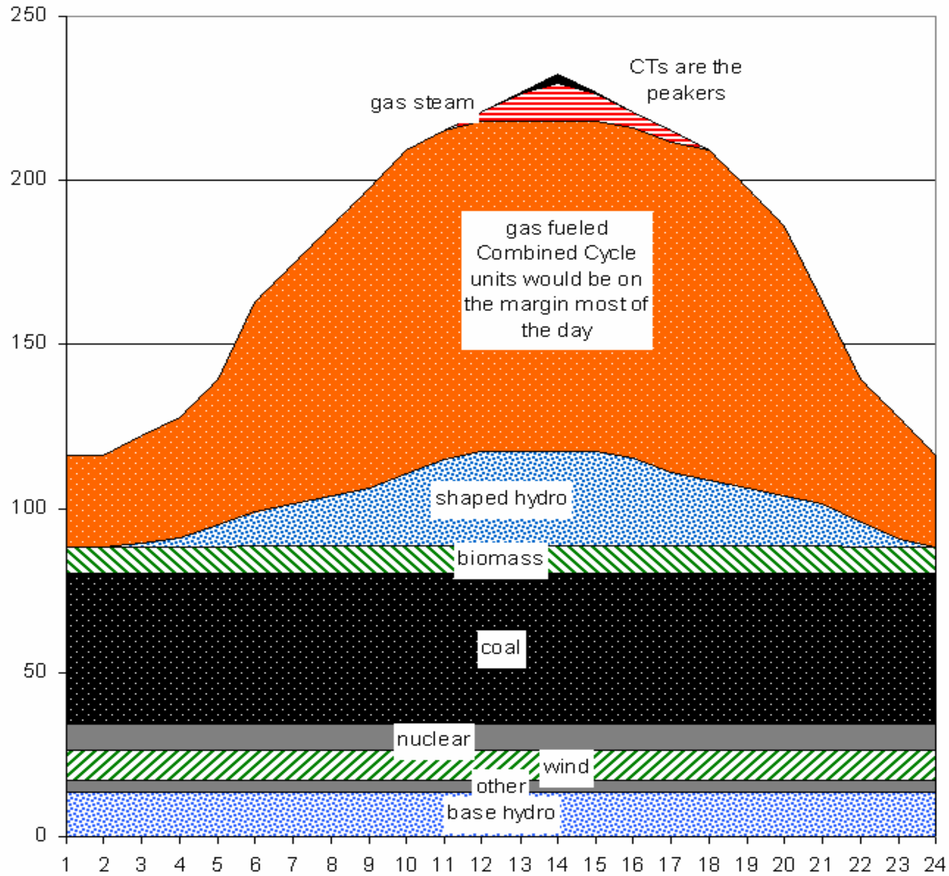

Figure 11. Generation for a typical August day in the final year of the first simulation.

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.

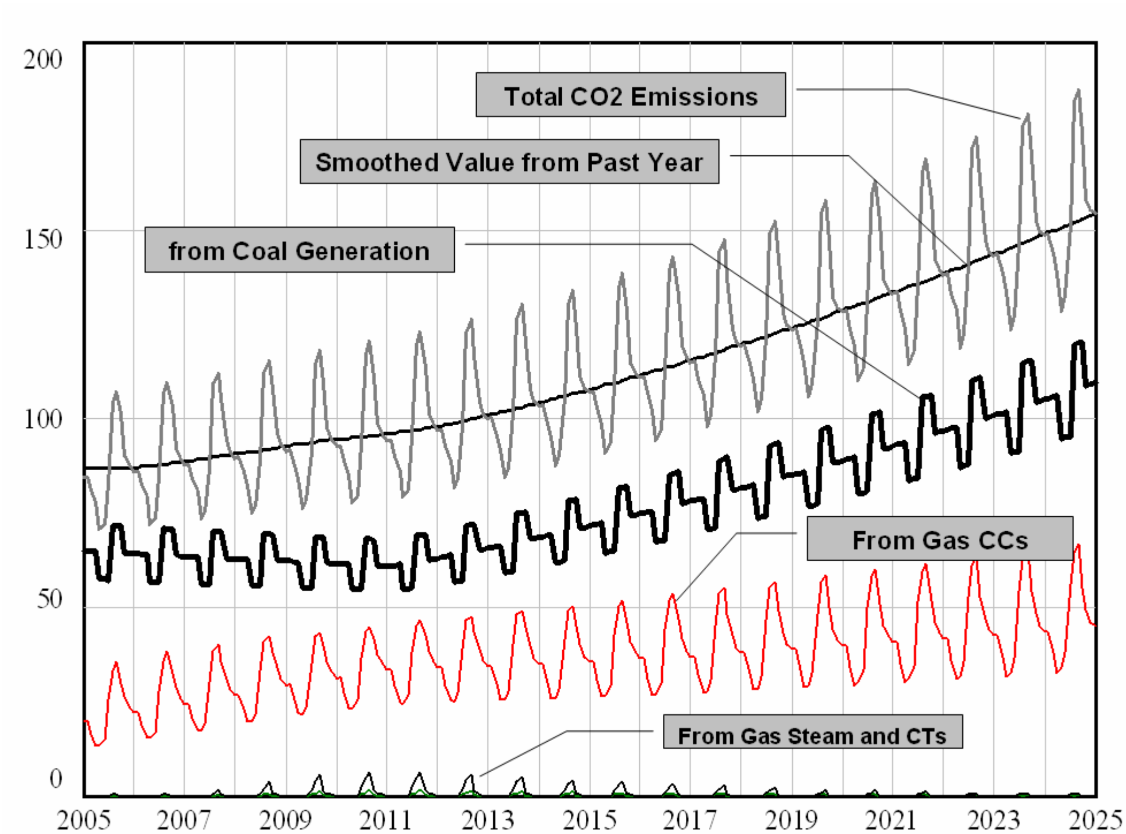

Figure 12. CO2 emissions (MMTC per year) in the first scenario.

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 will show that coal generation could be eliminated entirely in a secnario with S139.

7. The Response to S139 in the First Scenario

Summary of S139's Impacts

Figure 13 summarizes the long-term impact of S139 in the base case simulation. 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. This "Base Case" result for S139 was found by exogenously setting carbon allowance prices to follow the trajectory in Figure 2. All other assumptions were the same as in the base case simulation described previously. The model responded with changes in short-term operations and long-term investments.

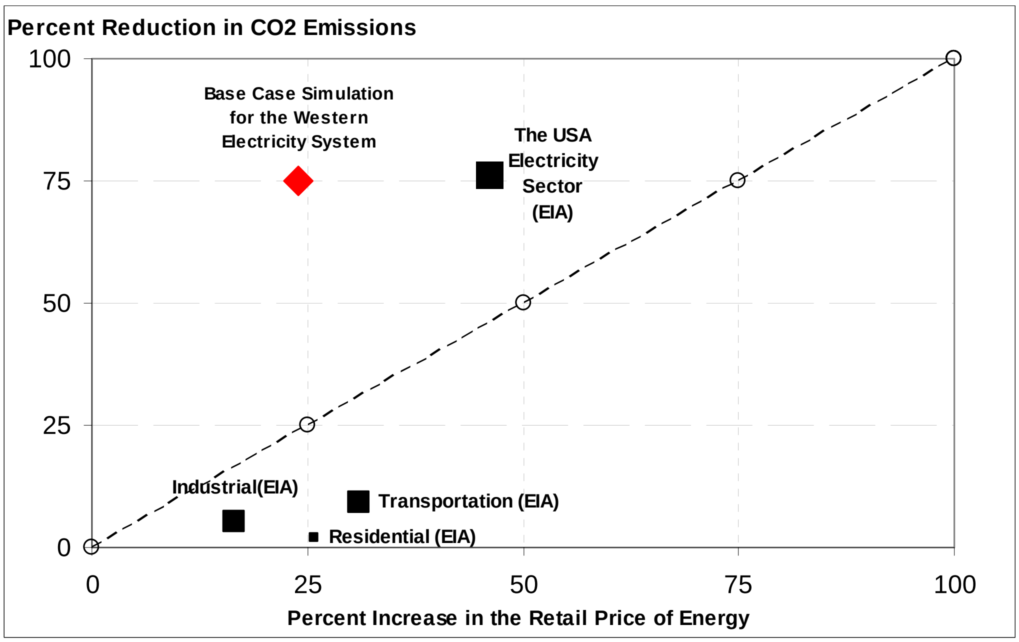

Figure 13. Comparison of the simulated WECC result with the EIA result for the nation's electricity sector.

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. These encouraging results are explained below.

Impact on Investor's Choice of Power Plant Construction

Figure 14 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 14. 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 14 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.

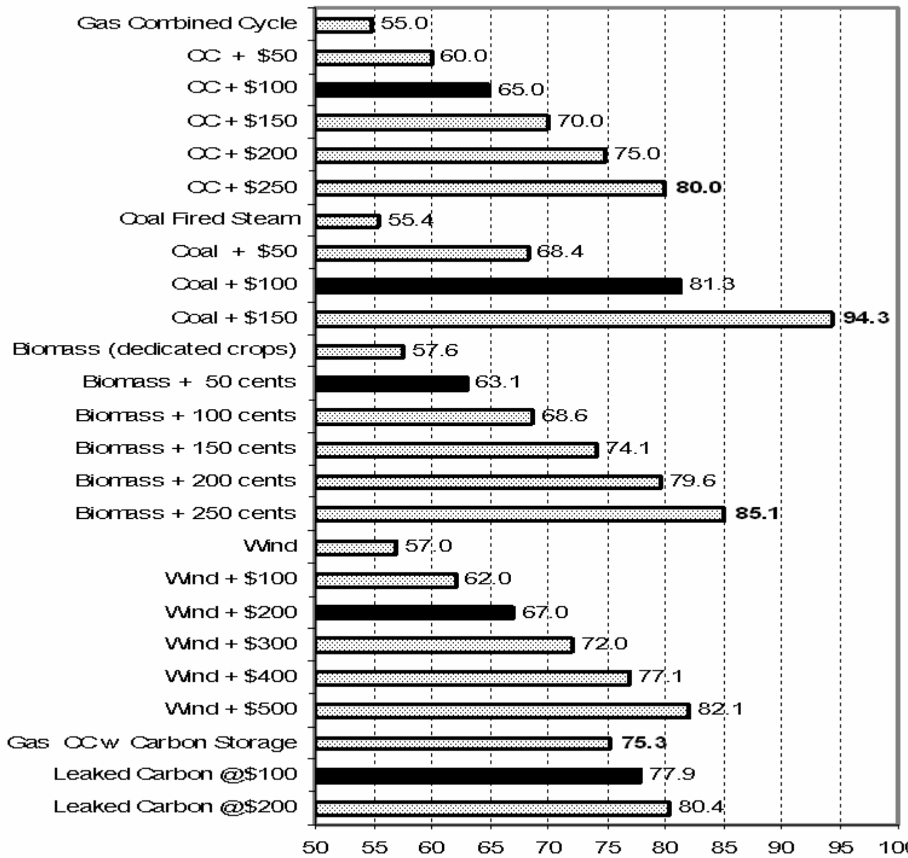

Figure 14. Investor total costs with highlighted bars for a carbon allowance price of 100 $/MTC.

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 14 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 14 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 14, 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 14 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 14 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 14 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 15 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.

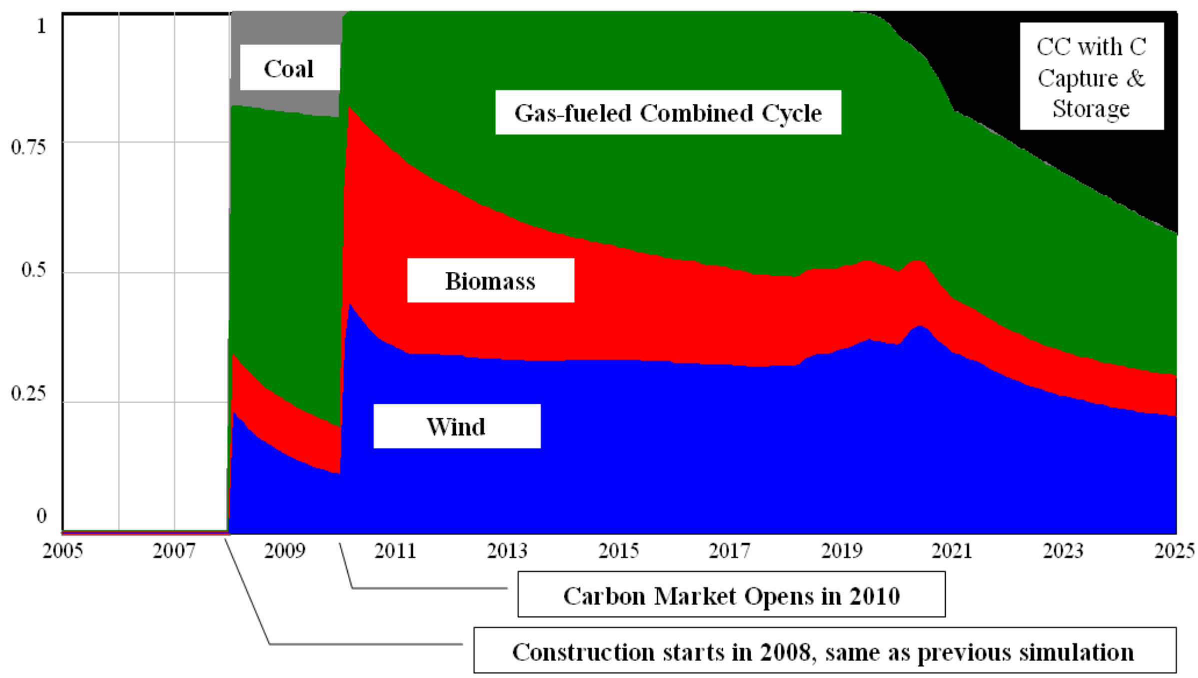

Figure 15. Construction market shares in the S139 case.

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.

Figure 16 shows the negative feedback loops that control construction market shares in the simulation with rising carbon prices. Starting at the top of the diagram, higher carbon prices drive up investors' cost of CCs. This increases the market share for wind capacity, so there is more total wind capacity, higher construction costs at the next location, an increase in investors' cost and a subsequent reduction in the wind market share in the future.

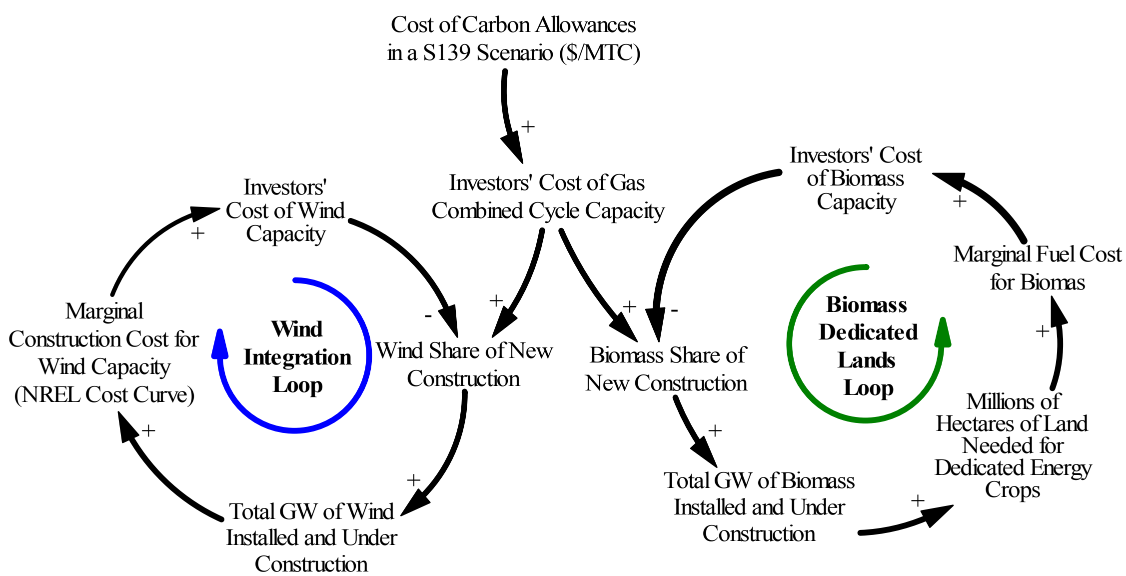

Figure 16. Feedback control of market shares as investors react to higher carbon prices under S139.

The "wind integration loop" provides negative feedback in the simulated system. Figure 16 shows a similar loop involving investment in biomass fueled power plants. As biomass captures a larger share of new construction, here is more total capacity, more land dedicated to energy crops, a higher cost of delivering the biomass to the power plants, higher investor costs, and a subsequent reduction in the biomass market share in the future. This "biomass dedicated lands loop" also provides negative feedback in the simulated system.

Impact on Generation

Figure 17 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. 17 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.

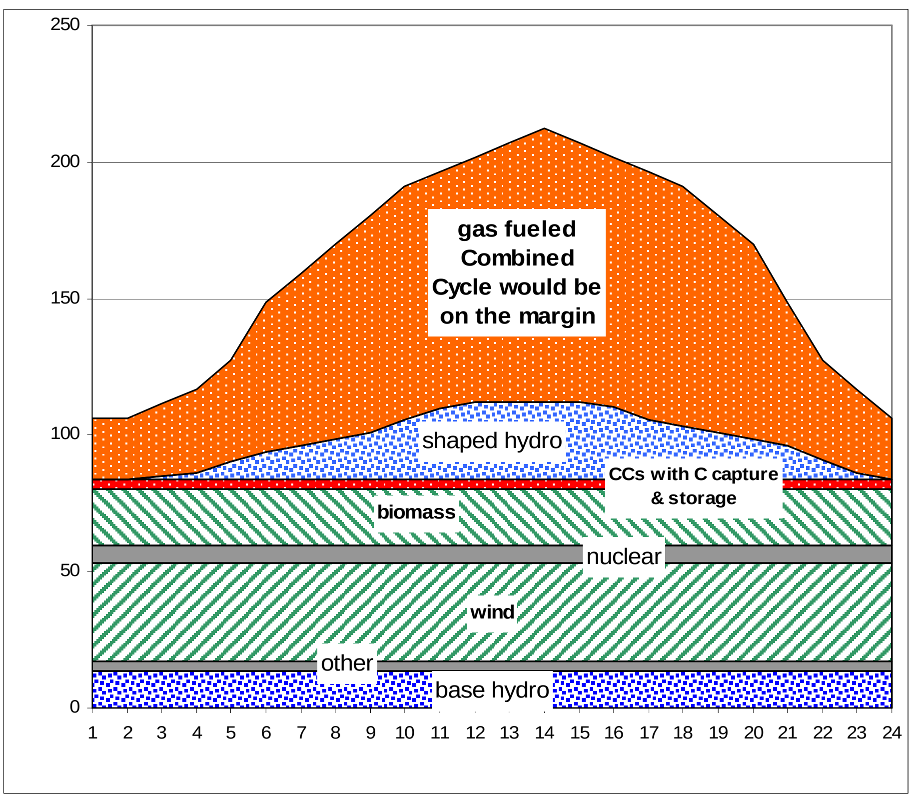

Figure 17. Generation for a typical August day in the final year of the S139 simulation.

Figure 17 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. These retirements occur mainly around 2020-2025; 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 power plant construction. (We assume that construction is timed to keep pace with the growth in demand and to replace retirements.) The model responds to the retirements by investing in new construction that will be needed to maintain adequate reserve margins. This added construction occurs around the year 2020. Based on the market shares shown previously in Figure 15, the replacement of the retired coal plants is approximately 35% wind, 15% biomass, 30% gas CCs and 20% gas CCs with carbon capture and storage.

Impact on Emissions and Retail Rates

Figure 18 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.

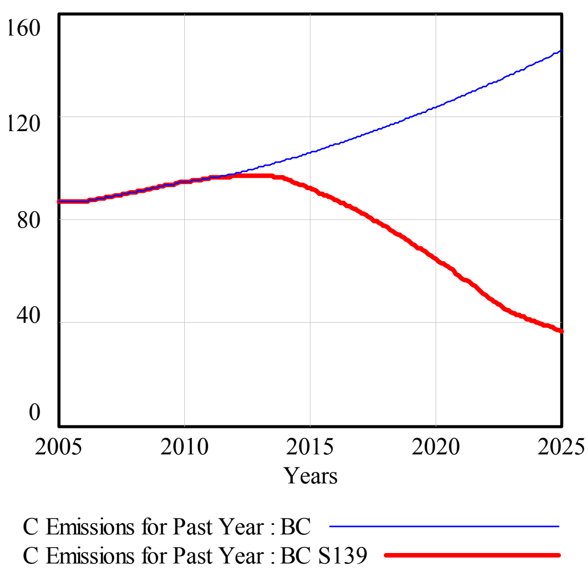

Figure 18. Simulated impact on the carbon emissions (in MMTC/yr) in the WECC

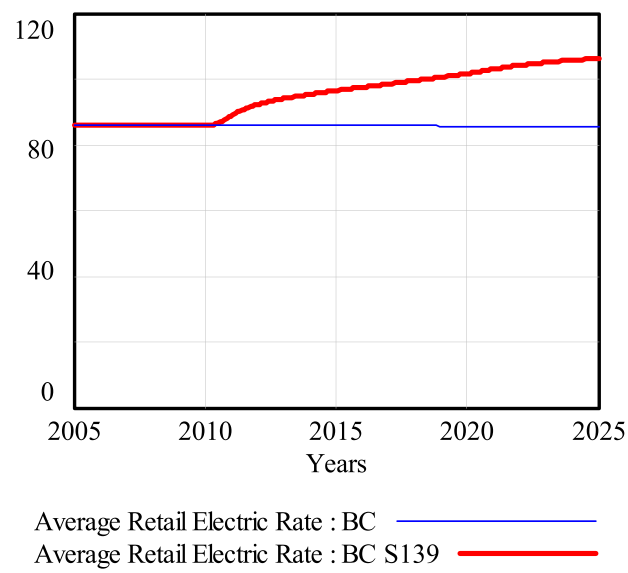

Figure 19. Simulated impact on the average retail rate (in $/MWH) in the WECC.

Fig. 19 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.

Testing the Importance of the Renewable Production Tax Credit

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 in the Fig. 13. And all 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. The new comparison showed that S139 would lead to somewhat different impacts by the end of the simulations:

- Reduction in CO2 emissions: 58% rather than the 75% shown previously
- Increase in the retail rate: 25% rather than the 23% shown previously.

These new results are located well above the 50/50 line used in this paper to interpret simulation results.

8. 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 more realistic 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. If we recalculate the levelized cost in Table I, for example, the cost of a gas-fired CC would climb by almost 14 $/MWH. So 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 20 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.

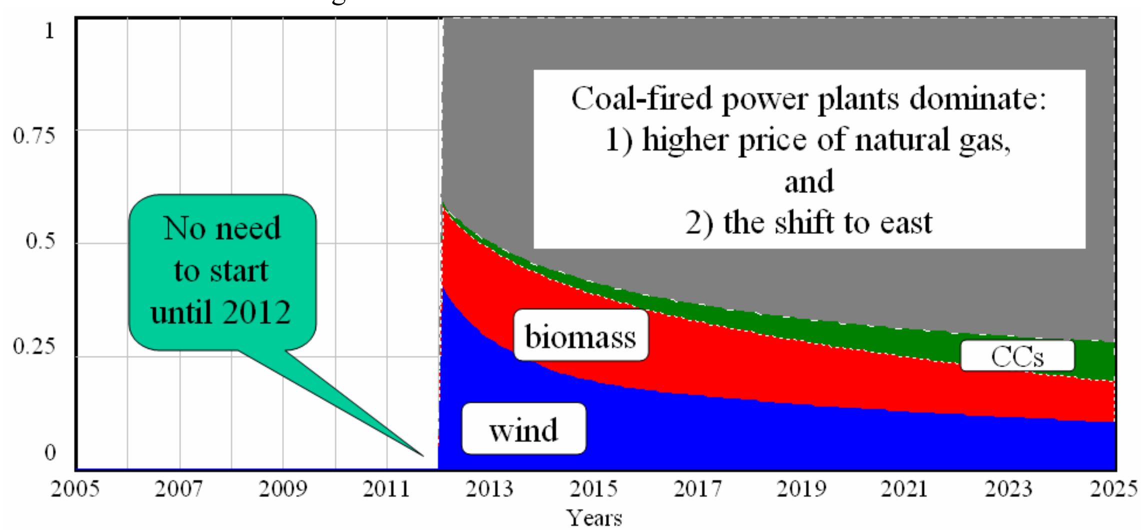

Figure 20. Construction market shares in the second scenario.

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.

Impact of S139 in the Second Scenario

Figure 21 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 21 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.

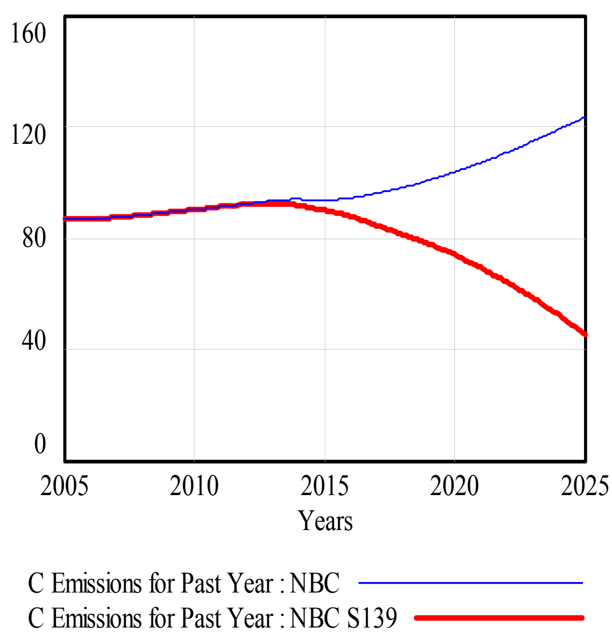

Figure 21. Simulated impact on carbon emissions (in MMTC/yr) in the second scenario.

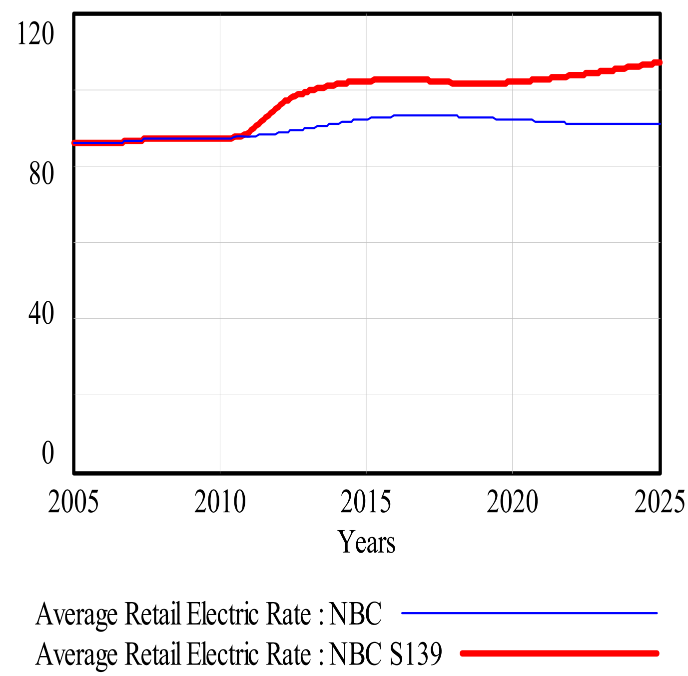

Figure 22. Simulated impact on the average retail rate (in $/MWH) in the second scenario .

Figure 22 shows the average retail electric rates in the second scenario. The thin, blue curve in Figure 22 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 22 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.

9. Summary of Results

Figure 23 summarizes the three sets of simulations reported in this paper. The base case results are located at the same position as shown previously:

- Carbon emissions would be reduced by 75%, and the
- retail price of electricity would be increased by 23%.

These results indicate that the WECC could achieve a dramatic reduction in CO_2 emissions, a reduction similar to the EIA estimate for the nation as a whole. The WECC could achieve this reduction with only half the increase in electricity prices that have been predicted for the nation as a whole.

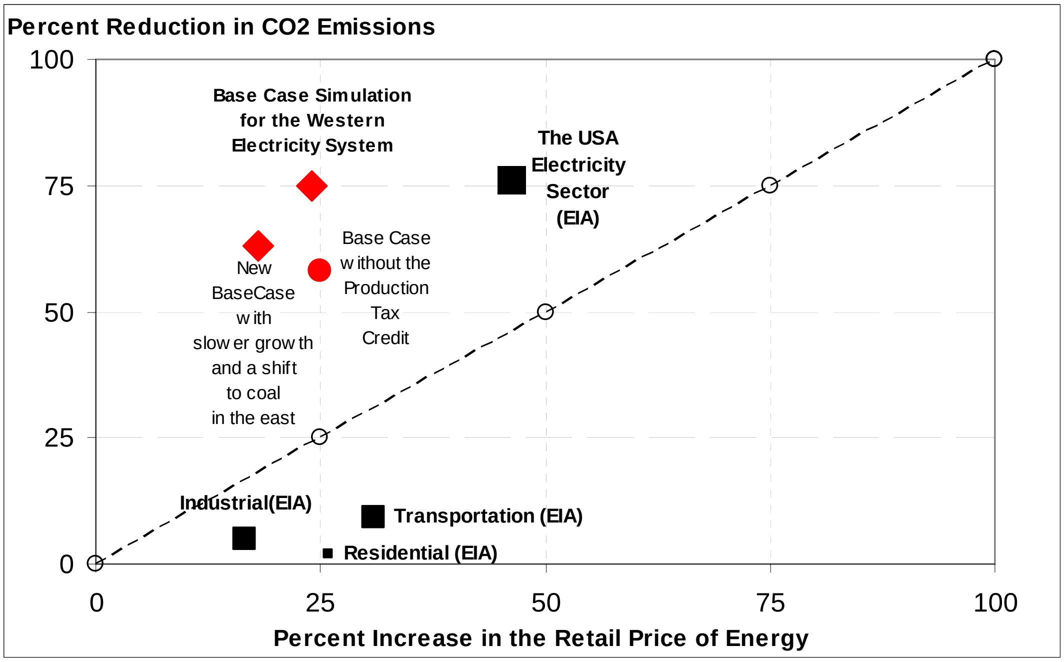

Figure 23. Summary results for the simulations reported in this paper.

The base case simulations assumed that the production tax credit for renewable generating technologies would be extended, as was done in the Energy Policy Act of 2005. However, if the tax credit were not extended, S139 is simulated to cause:

- carbon emissions to be reduced by 58%, and the
- retail price of electricity to be increased by 25%

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.

Figure 23 shows the results from the new base case with slower growth and the shift to coal plant construction in the eastern areas. The new simulations show that:

- Carbon emissions would be reduced by 63%, and the
- retail price of electricity would be increased by 18%.

Comparing the new results to the 50/50 line shows that the electricity sector still lies well above the 50/50 line, providing further confirmation that the western electricity system is similar to the nation's electricity system.

10. Policy Implications

The simulations shown here are the first major application of a new modeling approach to simulating large-scale power systems. The model provides a unique approach to simulating both the short-term and long-term response of electricity markets to policy changes. The results are a good starting point for additional analysis. Ideas for additional analysis are in the final appendix; recommendations for policy makers are discussed below.

<u>Implications for Creation of a National Carbon Market</u>

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 major initiatives are in the Northeast/Mid-Atlantic states and on the west coast. These initiatives are summarized below.

<u>The RGGI</u>

The first, major initiative is the RGGI, the Regional Greenhouse Gas Initiative of nine Northeast and Mid-Atlantic states. According to the *New York Times* (DePalma 2005),

The cooperative action, the first of its kind in the nation, came after the Bush administration decided not to regulate the greenhouse gasses that contribute to global warming. Once a final agreement is reached, the *legislatures of the nine states will have to enact it, which is considered likely… the regional initiative would set up a market-driven system to control emissions of carbon dioxide, the main greenhouse gas, from more than 600 electric generators in the nine states.*

The RGGI (2006 website) *Overview* reports that the cap and trade market would apply to fossil fuel-fired generators (25 MW and larger) starting in 2009. The initial cap would limit emissions to the value from 1990. The limit would then be reduced by 10% by the year 2018. Compared to S139, the RGGI goal appears to be 10% more ambitious (since S139 aims to control emissions to 1990 levels by 2016.) But this comparison is somewhat misleading as the RGGI market includes only the electricity sector, the most responsive sector in the economy.

The *Overview* reports that the market would be designed with a "safety valve" on the price of allowances. (If the price of allowances reaches this value, generators will be given additional time to "true-up" their emissions with the allowances.) The safety valve is set at $10 per short ton of CO2 (in 2005 dollars) and is escalated at 2%/yr. For comparison with prices in Figure 3, the safety valve is escalated to $11 per short ton of CO2 by 2010, which corresponds to around $12 per metric ton of CO2. Since the S139 market is expected to open with a price of $22 per metric ton of CO2, it is clear that RGGI working groups are expecting market clearing prices well below the EIA assessment of S139.

The working groups expect much lower price impacts as well. Their "best estimate" for the average retail price increase is around 0.5% by the year 2015. (In a scenario with higher prices for natural gas, electricity prices could increase from 2 to 3% due to the RGGI.) However, their *Overview* emphasizes that these small increases in electricity prices would not translate into higher electric bills. Because of improvements in end-use efficiency over time, the RGGI is expected to lower the participating households' annual electric bill by around $150 by the year 2021.

The West Coast Governors' Initiative

In September of 2003, the Governors of Washington, Oregon and California launched the West Coast Governors Global Warming Initiative (West Coast Governors 2004). Working groups from the three states have issued various recommendations for changes in standards (i.e., new appliance efficiency standards, upgraded building codes, light duty vehicle standards, and renewable portfolio standards). They also recommend initiatives such as "smart growth" and investment in rapid transit to reduce vehicle miles of travel. And most relevant to this paper, they have recommended that the Governors give careful consideration to the development of a regional market-based carbon allowance program.

A draft analysis of the West Coast recommendations was conducted by the Tellus Institute (2004). Under base case conditions, emissions in the three states were expected to grow to 774 MMTCO2/year by the year 2020. However, if a package of ten strategies were implemented, emissions would be 575 MMTCO2/year, a 26% reduction. To compare with S139, recall that S139 operates with emission capped at 1990 values by the 2016. So one might interpret the west coast strategies to be less ambitious than S139. But it is important to remember that, the EIA study, the S139 cap is imposed, and the analysts searched for the price of allowances that would reduce emissions sufficiently to come under the cap. Their result was the upward trajectory from $22 to $60 per MTCO2 shown in Figure 3. In the Tellus study, a collection of ten strategies were combined in an analysis of their collective impacts. The cap-and-trade market was included as one of the ten strategies, but it did not operate with a cap. Instead, it was represented with a fixed allowance price of $20 per MTCO2. With this price, one would expect the estimated reduction in emissions to be much less than those projected by EIA under S139.

The Oregon Initiative

The Oregon initiative began early in 2004 when Governor Ted Kulongoski appointed an advisory group on global warming. The *Oregon Strategy for Greenhouse Gas Reductions* estimates that Oregon GHG would climb to 60% higher than 1990 emissions by the year 2025. Their goal is to arrest the growth in GHG by 2010 and to achieve reductions toward a "benchmark for CO_2 of not exceeding 1990 levels. (OR Strategy 2004, p. ii).By 2020, they aim to achieve a 10% reduction below 1990 GHG levels. Looking much further into the future, they aim for "climate stabilization" emissions levels at least 75% below the emissions in 1990. CO_2 accounts for 84% of Oregon's GHG in the year 2020, and the CO_2 emissions come primary from electricity (42%) and transportation (38%). Electricity generation is primarily from hydro (43%) and coal (42%).

The *Oregon Strategy* (2004, p. 70) describes the RGGI proposal for allocation of carbon allowances to generating plants in the Northeast and Mid-Atlantic states, but it argues for a different approach in Oregon:

Designing allowances on GHG emissions for only those power plants located in Oregon would be inequitable for the states two largest utilities…Rather than a system based on generating plants located in Oregon, this action would develop a system to allocate emissions from utility power plants and purchases to their Oregon load and set the limits on those emissions. This system is sometimes referred to as a load-based cap-and-trade system.

Design of a load-based cap-and-trade system is under study by the Oregon Carbon Allocation Task Force (2006). The task force is considering several measures, but their priority "will be to develop a carbon allocation standard that limits and reduces over time the CO_2 emissions from the use of electricity in Oregon as it is supplied by utilities." A preliminary "straw proposal" assumes that "all free allowances are allocated based on 2004 emissions and 5% of allowances are auctioned. The Task Force estimated the increase in the utilities' retail revenue requirement from this proposal. The analysis allows for two approaches to achieve compliance. In one approach, the utility acquires conservation and renewable resources above market costs. The task force then estimates the retail revenue impact based on the \$/MWH cost above market. In the other approach, the utility purchases the allowances. The task force then estimates the retail revenue impacts based on the \$/MTCO2 for allowances. The high-end of the estimated impacts is a 6% increase in the 2004 retail revenue requirement for one utility and a 13% increase for the more coal-dependent utility. The range of estimates reveals the uncertainty in impacts, but the Task Force emphasizes that upper-end estimates are firm because the design of the straw proposal effectively limits the cost of compliance at 40 \$/MTCO2.

California Initiatives

California has announced two important initiatives this year. In February, the California Public Utilities Commission (CPUC) announced that it would develop a cap on GHG emissions for the state's Investor Owned Utilities (IOUs) and the non-utility companies that provide electric power to customers within their service territories. The CPUC (2006) explains 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 announcement acknowledges the pioneering effort of the RGGI, but the California proposal would be organized as a "load-based" cap in which the cost of allowances are born by the regulated IOUs which distribute electricity to retail customers. (In the RGGI proposal, the cost of allowances is born by the generating companies.) The February announcement is the first step to establish a load-based cap-and-trade system. According to the *San Francisco Chronicle* (Baker 2006),

Today's vote would merely begin the process of setting a specific cap, with the key details to be worked out later in discussions with environmentalists and the state's three investor-owned utilities. … Michael Peevey (President of the CPUC) said the process of nailing down the cap's details would take several years.

The other important California initiative occurred in April of this year. Fabian Nunez, the Democratic Speaker of the California State Assembly, introduced a bill to place a mandatory cap on emissions of greenhouse gases in the state. According to the *EEnergy Informer* (2006), the goal is to limit California's GHG to 1990 levels by the year 2020, which would require a 25% reduction from emissions expected without the legislation. The bill would apply to all emissions, not just the emissions from the electricity sector.

Implications for State Policy Makers

States on both the East Coast and the West Coast are engaged in discussions to develop carbon markets. The state policy makers are wise to focus their attention on the electricity sector. And as they look to the long term, they are wise to focus their attention on coal-fired generation. These are two of the more important implications from the simulation results presented in this paper.

This paper explains that the western electricity sector could contribute major reductions in CO2 emissions with carbon allowance prices following an upward trajectory from 22 to 60 \$/MTCO2. In a scenario with rapid growth in demand, CO2 emissions could be cut by 75% by the year 2025, and the increase in the average retail electric rate could be limited to 23%. These and other results are displayed in two-dimensional charts to show the % reduction in CO2 emissions versus the % increase in the average retail rate. The charts show that the electricity sector would lie well above the 50/50 line used to distinguish between major sectors of the economy based on their responsiveness to a carbon market. The EIA results for the nation show that the electricity sector would be the most responsive. Our study of the WECC shows that the western electricity sector could be just as responsive.

These general findings are directly relevant to the state initiatives because each of the states has focused much of their attention on the electricity sector. This is partly due to the states' historical authority in electricity regulation. But it is also due to the recognition of the potential responsiveness of the electricity sector, especially if incentives are in place to promote investment in renewable generation. The state studies conducted to date envision modest reductions in electricity sector emissions and small increases in the average retail rates. The studies assume a wide a range of different prices for carbon allowances. For example, the RGGI analysis suggests that carbon allowance prices would be well below a safety valve of 12 \$/MTCO2, and the Tellus (2004) study of a west coast carbon allowance program assumed a fixed price of 20 \$/MTCO2.

These and other state assumptions for carbon prices lie at the low end of the price trajectory used in this paper. This makes sense in preparing estimates of the likely impacts early in a cap-and-trade program. As time goes on, however, the electricity sector is likely to achieve much larger reductions in CO2 emissions if the nation's total emissions are to be brought under control. In our simulations, the most dramatic reductions in CO2 emissions occur when the carbon allowance price reaches the point where it is no longer economic to operate older coal plants. This occurs when the variable cost of the older coal plant is driven higher than the variable cost of operating gas-fueled CCs. When this happens, the older coal plants are retired, and the region's emissions decline rapidly. State working groups will be able to estimate the allowances prices that could trigger the longer-term phase out of coal generation in their region and in their scenarios. In the examples presented here, the operation of the older coal plants became infeasible when allowance prices reached the range of \$40 to \$45 per MTCO2. In a second scenario with higher prices for natural gas, the phase-out occurred when allowance prices reached the range of \$50 to \$55 per MTCO2.

The simulations shown in this paper show that wind and biomass generation could grow dramatically in the west with carbon allowance prices following a trajectory from 22 to 60 \$/MTCO2. Wind and biomass are simulated to provide 37% of total generation in a rapid growth scenario even when we adopt the conservative assumption that there are no improvements in their costs and performance in the coming 20 years. There are major land-use and planning implications for a system with so much wind and biomass generation. These are the subject of suggestions for further research given in the final appendix to the paper.

Appendix A. Goal of the NSF Project

The goal of the NSF project is to develop a new approach to modeling of large scale power systems by combining engineering methods and system dynamics methods in a novel fashion. The strategy is to build upon the previous modeling at WSU. This appendix summarizes the previous work and explains why a novel approach would be useful.

Previous Modeling at WSU

Figure A-1 shows the spatial and temporal boundaries of previous models developed at WSU. The modeling of system security is represented by the box located at the base of the diagram. The security model represents the power flow in the steady-state and dynamics ranging from fractions of a second to several seconds. Loads are aggregated at the level of sub-stations, while the scope of the model extends to cover the entire WECC representing more than 10,000 nodes in the current model. This model can calculate power flows, real and reactive reserves and system limits for a specified scenario.

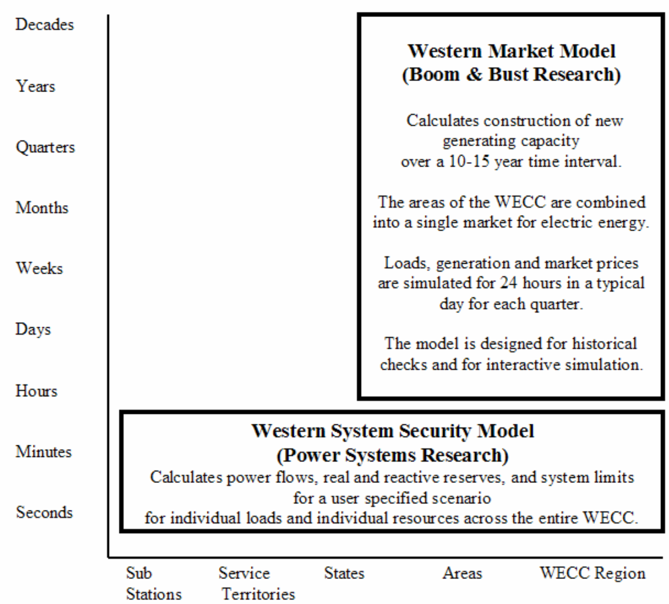

Figure A-1. Spatial and temporal boundaries of previous modeling at WSU.

The upper box depicts the previous system dynamics modeling of the western electricity market. The model operated with load and resource data from the four regions of the WECC. The model simulated hourly operations for a typical 24-hour day in each quarter of a year. The model assumed adequate interconnections between loads and resources in the west, so the wholesale market was represented as a single market. The simulations began in 1998 and ran for a decade or more to allow sufficient time to see the boom and bust in power plant construction. The model was applied and verified by comparison with WECC conditions during 1998-2001. The wholesale market model was constructed to help one understand if power plant construction would appear in waves of boom and bust. The boom/bust pattern is common in industries like commercial real-estate which face long lead times to bring new capacity to market (Ford 2002). Construction of new power plants can also appear in waves of boom and bust. The resulting cycles in wholesale prices and reserves can be devastating for an industry in which production and consumption must occur simultaneously across a complex grid.

Investment in new generating capacity was based on an endogenous theory of investor behavior, which included the long delays for permitting and construction. Investors were represented as “merchant investors” weighing the risks and rewards of investing in CC capacity based on estimates of future market prices. The theory was tested in the WECC system and found to be successful in explaining the under-building that occurred in 1998-1999 and the over-building that appeared in 2000-2001. The simulated pattern of boom and bust was attributed to a combination of the delays in power plant construction and the real limitations on investor's ability to anticipate the future trends in the wholesale market.

Market prices were based on the simulated actions of a system operator which finds the wholesale price for each hour to bring forth the generation to meet the demands for electric energy and ancillary services. Some generation (such as hydro and nuclear) was bid as "must-run" capacity. Most generators were assumed to submit bids at their variable costs. However, some generators were assumed to submit bids well above variable costs, a form of strategic behavior known as economic withholding. Without strategic behavior, the simulated prices reflected competitive conditions, so the results were checked against the "counter-factual" benchmarks published by the California ISO. With strategic behavior, the simulated prices were shown to rise far above the published benchmarks during intervals with low reserves. These prices were checked against actual prices reported by the California ISO.

The previous model was implemented with Stella®, one of several software programs that facilitate the development and use of system dynamics models. Figure A-2 shows a view of the Stella model part way through a simulation.

This graph shows the historical prices as they appear on the main screen of the previous model. Stella information buttons are used to highlight the variable names. The graph shows the hourly prices rising and falling through a regular, daily pattern during 1998-1999. But the pattern changes dramatically in the year 2000. The peak hour price climbed to 200 \$/MWH in the spring of 2000 and then went "off the chart" for the next four quarters. Quarterly average prices climbed to well above 200 \$/MWH, and the annual price climbed to well above 100 \$/MWH.

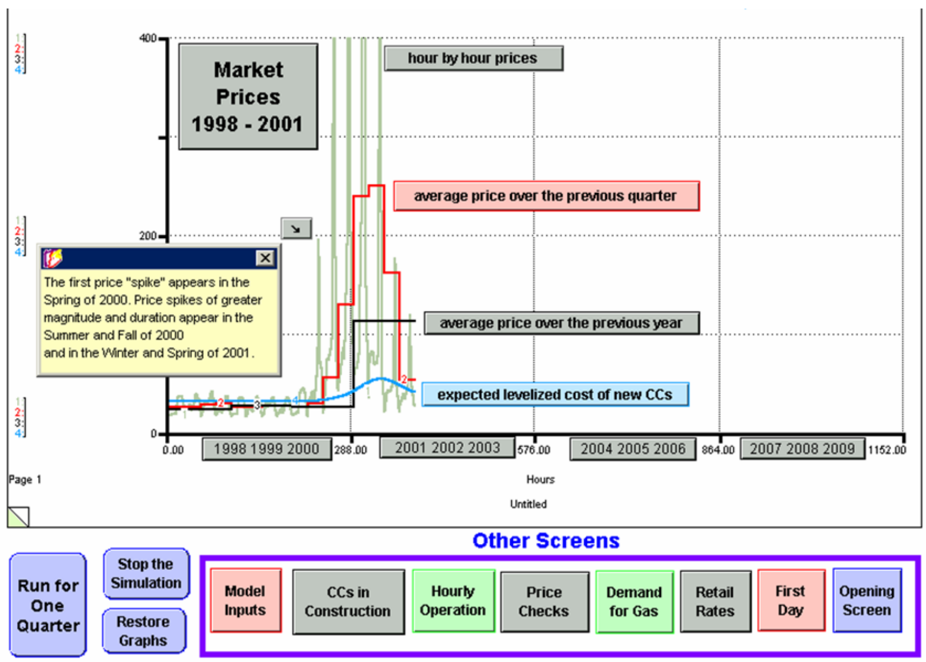

Figure A-2. Simulated market prices on the main screen of the previous model of the WECC wholesale market.

The previous model was used to demonstrate that these price spikes could reappear without major changes in the design of wholesale markets (Ford 2001).

System Dynamics for Rapid, Interactive Simulation

The wholesale market model was constructed using system dynamics, a simulation method pioneered by Forrester (1961) and explained in texts by Ford (1999) and Sterman (2000). System dynamics has its origins in control theory and has been defined by Coyle (1977) as that "branch of control theory which deals with socio-economic systems and that branch of management science which deals with problems of controllability." The method has been put to good use in the electric power industry (Bunn and Larsen 1992, Ford 1997, Ford 2002, Kadoya 2005, Olsina 2006, Vogstad 2005) where it is valued in a rapidly changing industry with high uncertainty and high risk (Dyner and Larsen 2001).

The previous model was designed for highly interactive simulation to promote learning in a group. This approach is in stark contrast to the way most models are used in the electric industry. From our experiences, most models are maintained by a small team of analysts who are proficient in the model, the supporting data and the software. The analysts use the models to prepare reports, and the rest of the organization benefits from the reading the reports. This mode of analysis and communication has evolved over time because of the complexity of models and their supporting software.

But models do not have to be used in this manner. An alternative mode of communication is provided by highly interactive models, sometimes called management flight simulators because they provide managers an opportunity to "experience" and discuss the simulated dynamics. Management flight simulators are highly valued for engaging student involvement in the classroom (Ford 1999, Sterman 1992) and for improving the learning of a diverse mix of professionals in large organizations (Morecroft and Sterman 1994). Models of electric systems may also be designed to promote highly interactive simulations and group learning, as has been demonstrated in recent research for the Electric Power Research Institute (EPRI 2000) and the CEC (Ford 2001).

Goal of the New Model: Greater Speed and Realism

The rapid simulation response of the previous models made interactive experimentation possible. But simulation speed began to be a problem as the previous system dynamics model was expanded over time. The decline in speed is a problem because of the unusual measure of time. Looking closely at Figure A-2, the reader will see that time is measured in hours. The model simulates a typical day for each quarter. With this approach, the model was able to reproduce the unusual prices that occurred during 1998-2001, but each year of the simulation required 96 hours of simulated time. Simulating 96 hours would normally be quite fast, but the previous approach required an extremely small step size (called DT in system dynamics modeling.) A small DT was required for the model to accurately simulate the ISO price setting operations and to capture the "price spikes" that could appear during the peak hours of a day. For example, if the DT were set at 1/16th of an hour, the model would require 1,536 steps to complete a simulated year. Running the model for the 11 years in Fig. A-2 would require over 18,000 steps. Consequently, the model's speed began to be a problem for rapid, interactive simulation.

The problem of slower simulations acted to curb our enthusiasm for further expansion of the previous model. We were particularly interested in two lines of work to improve the realism of the model:

1. First, we wanted to move from simulating a typical day/quarter to a typical day/month, a change that would increase the simulation times by three-fold.

2. Second, we wanted to move from a single area model to a multi-area model with transmission interconnections. The expanded model would then be used to show the power flows subject to engineering constraints on the transmission network. Expanding the model in this direction would lead to still further deterioration in simulation speed.

At some point, the previous approach would become too slow to serve as an interactive simulator suitable for group learning. A new approach was needed, and we looked for a way to combine the engineering approach with the system dynamics approach. Our goal was to improve both the speed and the realism of the previous model of the western electric system.

Appendix B. Electricity Demand

The demand for electricity is specified separately for each area in the west. The model user specifies an upward trend in demand that is expected to occur if retail prices were to remain constant. When prices do change, the model keeps track of the feedback effects on demand. The model then uses shaping factors to separate the annual peak demand into peak demands in each month of the year. A second set of shaping factors separates the demands into demands for each hour of a typical day in the month.

User Controls on the Growth in Demand

Figure B-1 shows a view used to experiment with different assumptions on the growth in demand. The left-side shows sliders to control the demand growth rates that would appear in different parts of the WECC if there were no changes in the retail price of electricity. (These growth rates were used in the second scenario described in the body of the paper.) Retail rates do change in the second scenario, as shown in Figure 22. We assume that consumers will react to the price changes based on user-specified lag time and price elasticity. For this simulation, we set the price elasticity at a negative 0.5, and we assumed a 60 month first-order lag to represent how the response is spread out over time. (This means that roughly two-thirds of the consumers' response to price changes will appear within five years.)

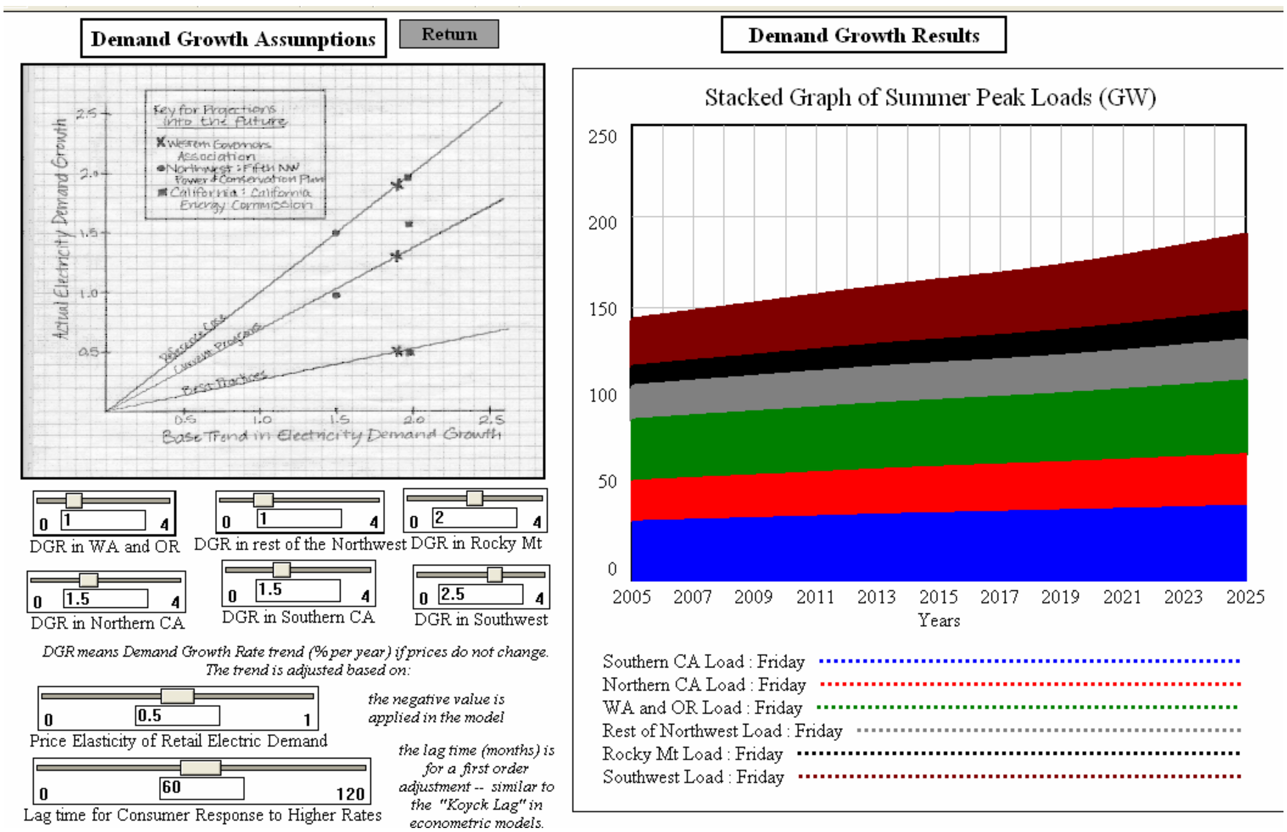

Figure B-1. View of main demand growth assumptions and the summer peak loads in the second scenario.

The right side of Figure B-1 shows the growth in summer peak loads in separate areas. Notice that the summer peak is just less than 150 GW in the first year. This value corresponds to the peak shown in August of the first year in Figure 7. Figure 7 represents the first scenario, a case with 2.5%/year growth in all areas, and the summer peak reaches 233 GW by the end of the simulation. Figure B-1 is a scenario with slower growth; it shows around 190 GW for the summer peak in the final year of the simulation.

The left side of Figure B-1 is a scanned pencil sketch to summarize various studies of utility and state conservation programs that can slow the growth in demand. The chart is organized with a "base trend" for the growth rate on the horizontal axis. The vertical axis shows the growth rate that the user might insert with the sliders. The "reference case" line is drawn at a 45 degree angle to show demand growth rates that match the "base trend." This reference line makes sense if there were no conservation and efficiency programs by the states and the utilities.

But many of the western states have successful programs to encourage consumers to use electricity more efficiently. We have reviewed recent studies by the Western Governors' Association (WGA), the Northwest Power Planning Council (NPPC) and the California Energy Commission (CEC). The studies describe the savings from conservation programs and from solar programs. The solar programs promote customer use of solar energy (i.e., installation of photovoltaic panels on the roofs of homes and businesses), but they contribute a very small reduction in electricty demand. Consequently, our review focuses on the reduction in demand growth rates to be achieved from conservation programs. The sketch helps one anticipate the extent of the reduction. For example, the position of the symbols show the estimates of the demand growth rate with and without the "current programs" to promote efficient use of electricity. Additional symbols show the demand growth rates if efficiency programs were accelerated to achieve "best practices." The sketch helps the model user make reasonable choices for the trends in demand growth rates. For example, the slider for the growth rate in the Northwest is set at 1 %/year which is consistent with the view that the upward trend would be 1.5%/year in the absence of efficiency programs and that 'current' programs reduce the upward trend to 1 %/year.

Several of the state studies of strategies to reduce GHG include an emphasis on more aggressive conservation programs. Such programs would be represented in the model by changing the demand growth rates to go beyond the "current program" estimates shown in Figure B-1. For the simulations of S139 shown in this paper, however, we adopted the conservative assumption that utility conservation programs would be the same in scenarios with and without S139.

<u>User Control of the Shape of Demand</u>

Monthly shaping factors are used to convert the peak demand in each year to peak demands for each of the 12 months in that year. These factors differ from area to area. The Northwest peak demands appear in the winter, so the monthly shaping factor assigns the Northwest peak load in December and January. In contrast, the Southern California peak load is assumed to appear in July and August of each year.

The model operates with time in months. The load in each month is represented by a collection of 24 loads, one for each hour of a typical day. The daily load factors differ from area to area. They may also differ from month to month. In the Northwest, for example, the daily shape may be quite different in the winter and summer. In June –September, for example, the daily load shape may be relatively flat in the middle of the day with the peak occurring around the same time as the peak in the areas to the south. In the rest of the year, however, the Northwest may show a morning peak around 8am and an evening peak around 8pm. These shapes may be entered in the model with a separate set of daily shape factors.

To keep the simulations simple, we operate the model with monthly shape factors fixed throughout the simulation. The fixed factors allow the seasonal patterns to appear each year in a predictable manner. This simplifying assumption which makes it easier to simulate the scheduled maintenance of thermal power plants We also keep the daily shape factors constant during the simulation. Some utilities may run "load management" programs to flatten their daily load shape to allow more efficient operation of generating capacity. Such programs are not the focus of our work, so we ignore them. This simplifying assumption makes it easier to simulate the daily operation of hydro generation (i.e., pumped hydro) which would be timed to generate during the peak hours.

Appendix C. Electricity Generation

The model's representation of electricity generation is evident from some of the results in the body of the paper. In Figure 7, for example, we see that the must-run generation makes the largest contributions in the spring of each year. In Figure 9, we see the effect of outages in the thermal units. The forced outages are apparent by comparing the total thermal capacity with the thermal capacity available in the summer of each year. The scheduled outages are apparent by the declines in the available capacity in the spring of each year.

The results in the body of the paper show total generation for the entire WECC. But the actual generation is calculated separately for each area of the west. We start with the "must-run units." These are simulated by user specified shaping factors to place the generation into the months and the hours in a realistic manner. The model subtracts the must-run generation from the demand to get the demand to be served by the wholesale market. The thermal units participate in the simulated wholesale market. We assume they submit bids based on their variable cost of operation. If the price of electricity exceeds their bid, the thermal capacity will be used to help supply the demand imposed on the spot market.

Figure 11 shows the operation of both the must-run units and the thermal units for a typical day in August at the end of the base case simulation. This diagram adds the generation from all areas of the west to show how the generation would meet the regional demand during each hour in the day. This appendix explains the details for each category of generation, starting from the bottom of the stack in Figure 11.

Hydro Generation

The hydro-electric generation is treated as must-run generation. ("Must-run" means that the timing of the generation is controlled by user-specified parameters and not by the wholesale price of electricity.) Hydro generation is provided by dams with large storage and by "run-of-the-river" dams with minimal storage. The dams with large storage that can shape their generation. The "run-of-the river" dams that must pass the water through as it arrives. The vast majority of the hydro generation comes from the Northwest dams, and their operation is constrained by the amount of water flowing down the rivers. In other words, hydro-generation is an energy-constrained system, not a capacity-constrained system. Consequently, user specifies the aGW of electric energy from hydro in each area of the west. With average year runoff in the Northwest, for example, the hydro-electric generation would be 21.5 aGW. (We allow for variations to deal with "adverse hydro conditions" or to simulate a breach in the dams on the Lower Snake River. But such variations are not shown in this paper.)

The energy from the hydro facilities is shaped to different months of the year based on user-specified factors. In the Northwest, for example, the shape factors ensure that the largest contributions come in April, May and June because these are the months of highest runoff. To keep the model simple, the monthly shaping factors are fixed over the 20-year simulation. (This assumption makes it much easier to schedule the planned maintenance of the thermal units.)

The monthly hydro generation is then shaped to the 24 hours of a typical day. The most important daily shape factors apply in the Northwest. We base these factors on daily patterns of river flow on the key dams on the Columbia. For the simulations shown in this report, the hydro generation is shaped within each day to provide around 33% above average generation during the peak hours in the middle of the day. The hydro generation is reduced by around 33% during the off peak hours at night. The end result is that on-peak generation is around twice as high as off-peak generation for a typical day.

The final category of hydro generation is pumped storage. This capacity is simulated entirely differently. These units provide generation during the middle of the day when the water is allowed to fall from the upper reservoir. We assume 40% pumping losses, so it takes 1.4 MWH to pump the water back to the upper reservoir for each MWH of generation from the falling water. There is around 3.5 GW of pumped storage capacity in California, but very little in the rest of the west. This capacity is operated as must-run generation with plausible assumptions about how the operator would schedule generation to take advantage of the higher prices in the middle of each day. We assume this capacity generates during a five hour interval surrounding the peak load each day. The water is then pumped up to the upper storage facility during a five hour interval in the off-peak hours each night. The negative and the positive generation from the pumped storage units are combined with the rest of the hydro generation in the display shown in Figure 11.

The Remainder of the Must-Run Generation

There is a small amount of "other capacity" in the WECC. Details on this capacity can be confusing in the WECC reports. Some of this is geothermal, and some is simply "other" with part of the other due to wind capacity. Since wind plays a major role in S139 simulations, we estimate the initial wind capacity separately and subtract it from the WECC reports on "other" capacity. Our definition of "other capacity" is around 3.7 GW. To operate this small resource, we ignore outage rates and assume that this capacity will provide 3.7 aGW of energy. For simplicity, we assign the same generation to each month of the year and to each hour of the day.

The wind capacity is simulated quite differently in the model. The investment in new wind capacity can be substantial, as shown by the construction market shares in Figure 15. We assume that wind developers will face difficulties as they move to more difficult locations (as explained in Figure 16). The difficulties translate into higher costs of wind construction, but the capacity factor is maintained constant at 33%. In other words, wind generation operates at 33% of the rated capacity in each area during each month of the year. (Of course wind is intermittent, and the cost of dealing with the intermittency is simulated in the model.)

Wind speeds can change dramatically during the course of a day, so wind generation can change from hour to hour. In some sites, the wind is strongest during on-peak hours. At other sites, the wind may be stronger during off-peak hours. The user may select from three daily-profiles to characterize the average profile for each of the areas in the west. One scenario calls for more of the wind generation to occur off-peak. The second profile calls for more wind generation during the on-peak hours in the middle of the day. The third profile calls for flat generation during the day. The flat profile was used in the simulations in this report, as is evident from the wind generation in Figures 11 and 16.

Thermal Units Operate in a Wholesale Market

The remaining generators are the thermal units. They operate in a wholesale market for electric energy. The available capacity is bid into the market at their variable cost, a combination of the variable O&M costs and the cost of fuel. Fossil fuel costs are expressed in $/million BTUs and are exogenous to the model. The variable O&M costs are also exogenous inputs to the model. Table I shows some examples: a new gas CC would experience variable costs around 42 $/MWH; a new coal plant around 12 $/MWH. These costs may vary from area to area based on differences in the delivered price of fuel. These costs also vary within each area based on a range of heat rates assigned to each type of generating capacity.

The model assumes that the owners of the thermal generating capacity bid their units into the wholesale market at their variable costs. A possible exception to this rule is a user-specified fraction of the gas-steam capacity which is subject to "economic withholding," which means that the capacity is bid into the market at well above the variable costs. We set the "strategic capacity" to zero in the simulations shown in this paper. We ignore withholding in the interest of simplicity. Also, it makes sense to ignore withholding because power plant owners would probably find withholding to be counter-productive with the high reserve margins in the simulations shown in this paper.

Forced and Scheduled Thermal Outages

Figure 9 shows that the available thermal capacity in the base case simulation. Figure C-1 provides a closer look by concentrating on the first five years of the simulation. This graph shows the total capacity across the entire WECC. The generation is calculated separately for each area, so the prices may vary between areas if there is congestion on the transmission lines. However, we set the available transmission capabilities quite high in the simulations in this paper. This allows the model to simulate the uncongested flow of power, and the electricity prices will be the same in all areas of the system.

Figure C-1 shows total thermal capacity in red. It grows during the first year due to some construction underway at the start of the simulation. Total thermal capacity then declines during the next four years due to retirements. The available thermal capacity is shown in green. Available capacity is lower than the total capacity due to forced and planned outages. The user specifies a forced outage rate and a scheduled outage rate for each type of thermal capacity. The forced outage rate is applied uniformly over the 12 months of a year. The scheduled outages are controlled by user-specified value for the "spring maintenance concentration factor." Much of the planned maintenance is scheduled the spring, a season with lower loads and higher hydro generation. This means that the "peak load to market" will be much lower in the spring, as shown by the blue curve in Figure C-1. The simulations shown in this paper assume that 50% of the planned maintenance is scheduled in the spring. The other half is split evenly between the fall and winter.

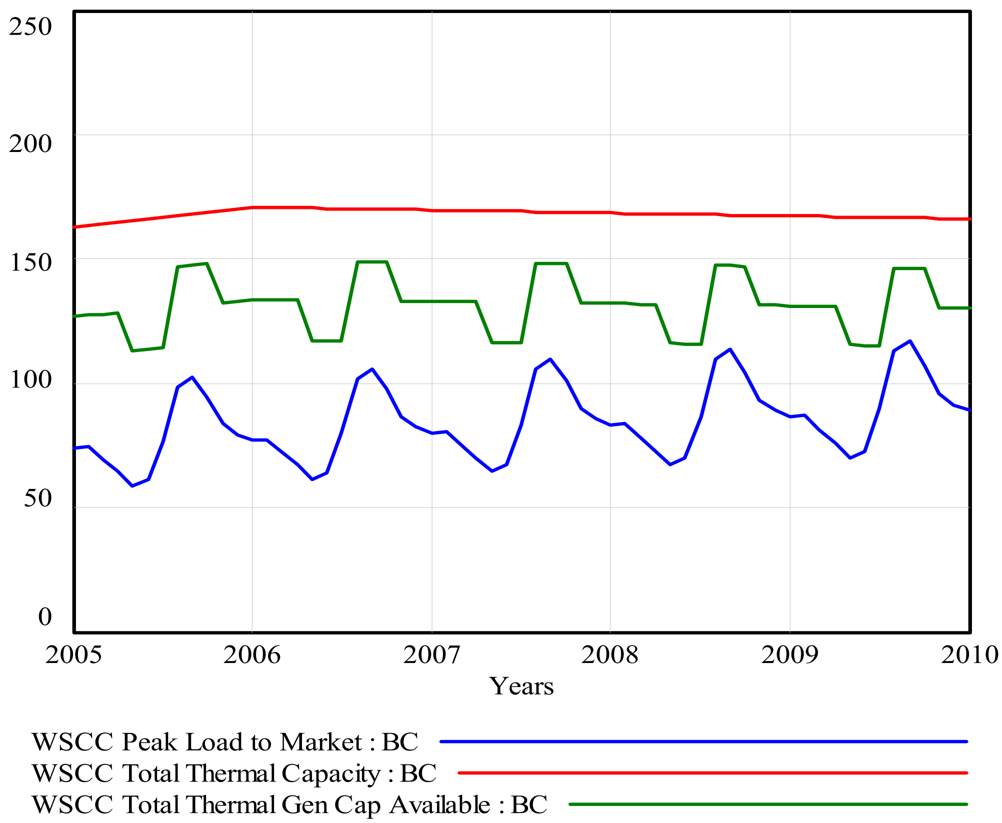

Figure C-1. Closer look at the thermal generating capacity in the first five years of the base case simulation.

The plausibility of the maintenance schedule may be checked visually by comparing the peak load to market with the available thermal capacity. The difference between these curves is the thermal reserves. If we see that the thermal reserves are much lower in one season, we may experiment with different values for the "spring maintenance concentration factor." When the thermal reserves are approximately the same across the seasons, we can proceed. Since monthly shaping factors for loads and hydro generation are constant during the 20-year simulation, we can be relatively confident that a good maintenance strategy at the start of the simulation will be good at the end of the simulation.

Appendix D. Wholesale and Retail Prices

Wholesale prices are calculated for a competitive spot market, as explained in Appendix F. Retail prices are calculated for an average rate charged by distribution companies subject to regulatory review.

Wholesale Prices

The simulations shown in this paper assume uncongested power flows throughout the region. This means that the wholesale market prices will be the same in each area (as explained in Appendix F). Wholesale prices in the base case simulation are shown in Figure 8. Figure D-1 provides a closer look by concentrating on the first five years of the simulation. The peak price is from 2 pm, the off-peak price from 2 am. Peak prices in the first year rise to just over 60 $/MWH in the summer months. These prices are sufficiently high to obtain needed generation from the region's gas-fired steam capacity. Figure D-1 shows that off-peak prices are relatively constant at just under 40 $/MWH. This price is sufficiently low for some of the region's unneeded gas-fueled CC to be shut down.

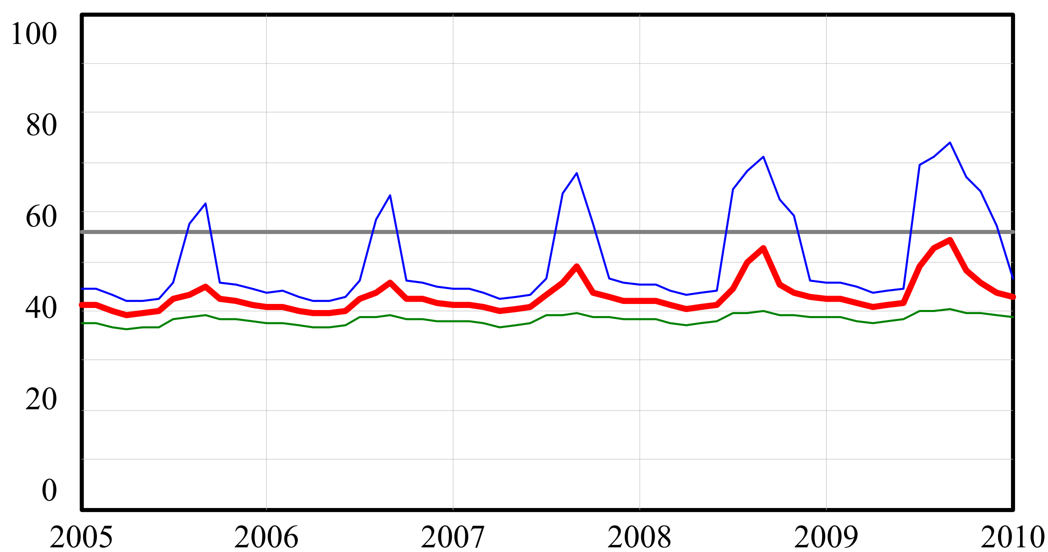

Figure D-1. Wholesale prices ($/MWH) in the first five years of the base case simulation.
The peak price is in blue; off peak price in green; average daily price highlighted by the thicker line in red.
The investor's full cost of building new capacity in area 1 the constant line in gray.

The average daily price is emphasized in red in Figure D-1. This is the best indicator of the revenues to be earned in the wholesale market. The base case shows average daily prices around 42 $/MWH during the early years. This is far below the value that investors are looking for to support the full cost of new power plants.

The gray line puts the investors' position in perspective. It shows the weighted average costs faced by investors building a mix of the generating plants shown in Table I. The weighted average cost is around 56 $/MWH. With the wholesale market clearing at 42 $/MWH, the market is 14 $/MWH short of the signal required to trigger new investment. However, investors could begin construction under such conditions if the Distribution Companies would sign contracts to cover the additional 14 $/MWH. We call this extra amount an "implicit capacity payment."

Wholesale prices in the S139 simulation are shown in Figure D-2. This time graph shows the many changes introduced by the carbon allowance market. The market opens in 2010 with carbon allowances selling for 22 $/MTCO2. This increases the variable costs of the gas-fueled CCs which tend to set the price during off peak hours. It also increases the price of the gas-steam units which often set the price during the peak hours. The cost of allowances also increases the cost of new power plants, as explained in Figure 14. Figure D-2 shows the simulation beginning with the average cost of new power plants around 14 $/MWH higher than the average wholesale price. This “implicit capacity payment” declines somewhat during the period from 2006 to 2012. By the end of the simulation, however, the implicit capacity payment has returned to around 14 $/MWH.

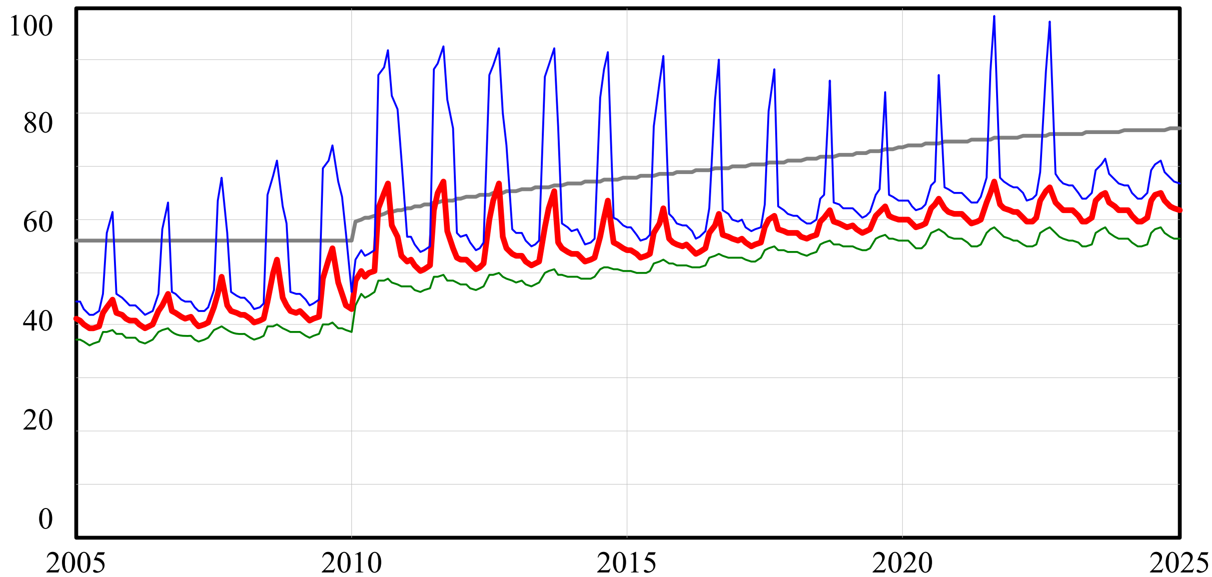

Figure D-2. Wholesale prices ($/MWH) in the first scenario with S139.
The peak price is in blue; off peak price in green; average daily price highlighted in red.
The investor’s full cost of building new capacity in area 1 is in dark gray.

Retail Prices

Retail rates vary widely across the west. They may change from one customer class to another (i.e., residential or commercial customers) even though they are served by the same utility. Retail rates may change dramatically from one utility to another (i.e., IOU or public utility) even though the utilities are in the same area. And finally, retail rates may differ dramatically from one area to another.

We do not represent the tremendous variation in retail rates across the region. Instead, we assign a standard retail rate at the beginning of the simulation. This rate applies to all retail loads in all areas. We then use the model to learn the percentage changes in the retail rate due to changes in simulated conditions.

The standard retail rate for the first scenario is shown in Figure 19. The rate is constant at 86 $/MWH. A constant 30 $/MWH is charged for transmission and distribution expenses. The rest is for generation.

The generation rate assumes that the average wholesale spot prices are passed through to retail after a 12-month regulatory lag. For example, this part of the generation rate amounts to around 42 $/MWH in the the early years of the first scenario. We then assume that the state regulators allow the Distribution Companies to pass along the implicit capacity payment that would appear in long-term contracts for new supply. This amounts to an additional charge of 14 $/MWH in the base case simulation. This would lead to a total generation charge of 56 $/MWH and a total rate of 86 $/MWH.

Appendix E. Investment in New Generating Capacity

Steady Construction or Boom and Bust?

Recent experience in the west indicates that construction of new generating capacity can appear in waves of boom and bust. We have simulated this pattern in previous modeling, as explained in Appendix A. But we do not choose to simulate a boom/bust pattern in this paper. Our purpose here is to look at the implications of a carbon market in the western system. For this purpose, we believe 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.

We operate the model with the general goal of 15% reserve margins under "critical hydro" conditions and we experiment with the starting date for construction that will meet this goal. The simulations begin with reserves at twice the goal, so construction does not have to begin immediately. Our experiments show that 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. Furthermore, we assume that state regulators pass the "implicit capacity payment" associated with such contracts into retail rates.

Construction Within Areas or Shifted to the East?

The base case scenario assumes that construction will occur in the same areas as the need. If there is rapid growth in demand in Area 1 (Washington and Oregon), for example, the new generating capacity needed to keep pace with that growth will take place in Area 1. In the second scenario, we assume a major shift in construction to the eastern areas. The major growth in demand may occur in the coastal load centers, but there could be major construction of new coal and wind capacity in the eastern areas. This scenario would require major transmission projects, such as the Frontier Line (2005). The model simulates such scenarios with user-specified factors to shift the construction to the eastern areas. The model may then be used to study the prices, emissions and power flows associated with the new pattern of construction.

Examples of Model Diagrams

The opening view of the model is shown in Figure 6. The gray comments in this view are navigation icons to allow the user to jump to different views of the model. This paper presents the model largely by the simulation results needed to show the impact of S139. In this appendix, we move to three of the views to provide a look at the model diagrams. To illustrate the explanatory nature of the model diagrams, we show portions of diagrams for the construction of gas-fueled CCs, coal-fired power plants and wind capacity.

The gas-fueled CCs would capture a major share of the new construction in the base case simulation. Their high market share arises from their competitive cost (see Table I) and the restrictions on construction of new coal plants in California. Figure E-1 shows how CC construction appears inside the model. This view shows some construction underway at the beginning of the simulation. This is entered as an exogenous input. The new construction is an endogenous variable. We simulate a 24 month lag before the initiations of construction translate into completed construction. This approach is implemented for each of the areas in the west.

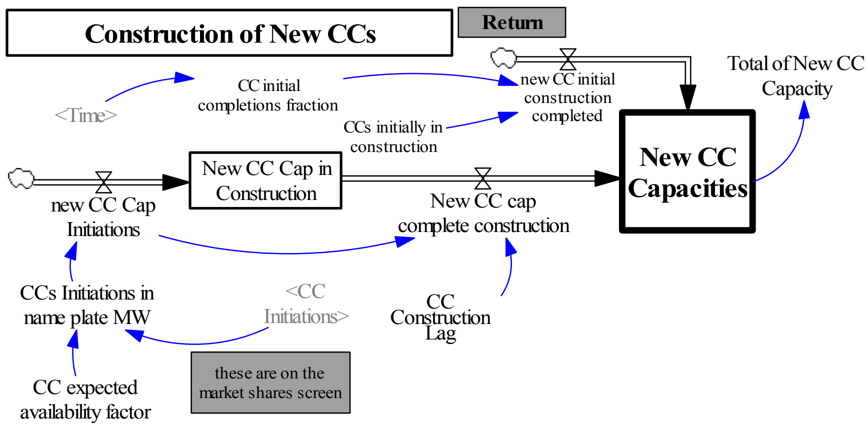

Figure E-1. Portion of a model diagram for construction of new CC capacity.

The body of the paper explains that coal-fired power plants would capture the major share of new construction in a second scenario with higher prices for natural gas and with a shift in construction to the eastern areas. Figure E-2 shows how the new coal construction is represented in the model. This view shows some similarities with the previous diagram. An important difference for coal, however, is the possibility for major retirements in a scenario with S139. The retirements are calculated endogenously, and they contribute to the need for new construction in order to "keep pace."

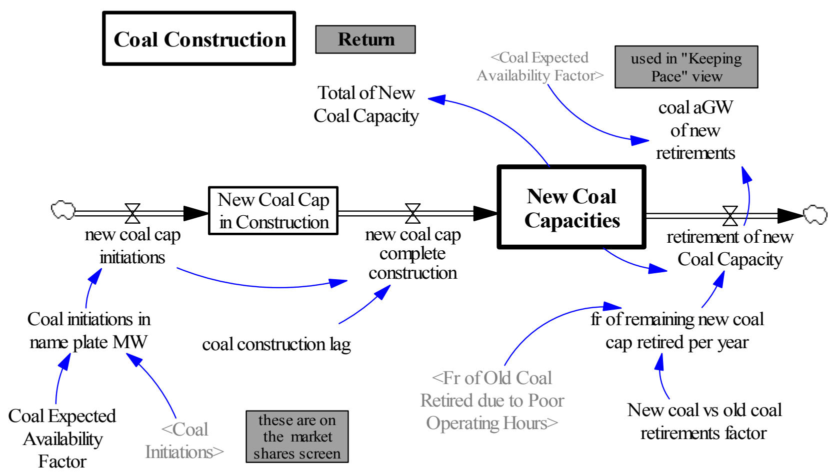

Figure E-2. Portion of a model diagram for construction of new Coal Capacity.

Wind is simulated to capture a large share of new construction in the scenarios with S139, as shown in Figure 15 and in Figure 20. Table I shows that wind is nearly competitive at the start of the simulation when we count the benefit of the PTC, the production tax credit. The simulation begins with a construction cost of $1,000 per kw. But this cost may increase over the years as investors deal with higher cost of transmission and the intermittency of wind generation.

These problems have been addressed by analysts at the National Renewable Energy Laboratory (NREL) using WinDS, the Wind Deployment Systems Model. The output of WinDS may be used to estimate construction costs in more highly aggregated models (like our model of the WECC). Figure E-3 shows several additional variables that are needed to keep track of the higher cost of constructing new wind capacity when the investors turn to more difficult locations.

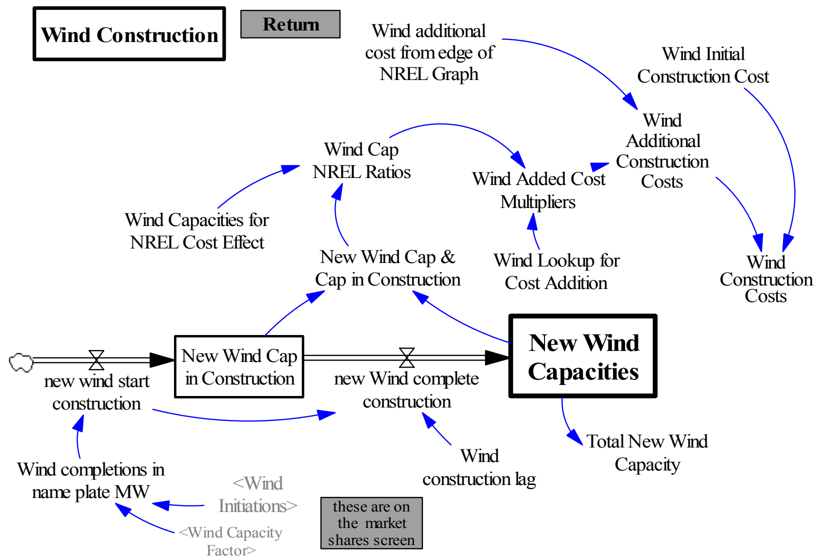

Figure E-3. Portion of a model diagram for construction of new Wind Capacity.

Figure E-4 shows how the additional costs appear in the base case simulation, a scenario with 2.5% annual growth and construction of new capacity within the same area as the need. This scenario would call for a large amount of construction in Area 1 (Washington and Oregon), and a significant portion would be wind. So we would expect to see large increases in the wind construction cost. Figure E-4 confirms the large increase in construction costs by showing total wind capacity on the horizontal axis and the marginal construction cost on the vertical axis. Results from two simulation are represented by dots, with the initial dots starting at a construction cost of 1,000 $/kw. By the end of the base case, there is 1.38 GW of wind capacity in the Area 1.

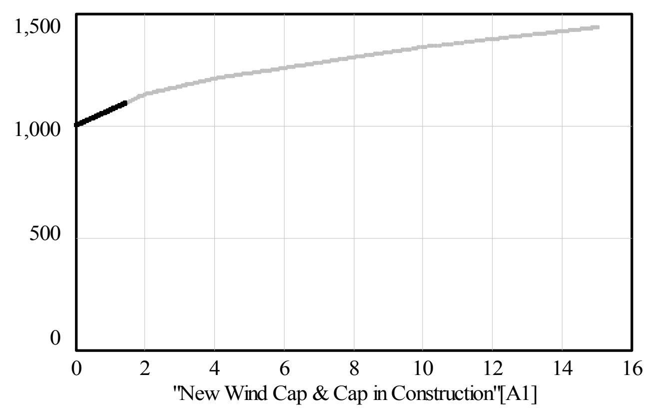

Figure E-4. Wind construction costs versus the total wind capacity in Area 1. The base case is represented by black dots; the S139 case by gray dots.

The gray dots show results from the S139 simulation. In this display, the S139 results overlap the base case results for low values of capacity. But there is a much greater investment in wind in the S139 simulation (as explained in Figures 14, 15 and 16). At the end of the S139 case, there would be over 14 GW of new wind on line and more under construction. The total is around 15 GW. With so much additional wind, the marginal construction cost has increased substantially. By the end of the S139 simulation, the cost to build additional wind is over 1,400 $/kw. In other words, investors are facing an extra 400 $/kw to deal with problems of transmission connections and intermittency by the end of the simulation. Figure 14 shows that this additional cost would push the levelized cost of wind to just over 77 $/MWH, far higher than the 57 $/MWH at the start of the simulation. The reason some investors are willing to still invest in wind at this point is that alternative technologies are nearly as expensive.

The model keeps track of the higher cost of building wind at more difficult locations. The higher costs influence the construction market shares, and they also show up as part of the retail price of electricity. However, we do not simulate the actual spending. For example, we do not simulate what is done with the extra 400 $/kw that is associated with wind construction at the end of the S139 simulation. This is a topic for further research, as mentioned in the final appendix of the paper.

Appendix F. Engineering Calculation of Power Flows

This appendix describes the incorporation of engineering calculations to deal with the physical constraints of the transmission system. These constraints can be more easily incorporated using an engineering approach because of its explicit mathematical nature. This appendix begins with the selection of software to best implement Optimal Power Flow (OPF) calculations within the system dynamics model. We then explain a compact version of a DC OPF which can be easily modified to allow for an approximate representation of the transmission system.

Software Issues

The Vensim simulation environment is used for our model because it allows for calling of external functions during the simulation. The gateway for these external functions in Vensim is provided via a dynamic link library (DLL). The library is usually created in a C/C++ developing environment, but other languages may also be used. This DLL can contain any number of functions and it can also call other DLLs. Calling other DLLs is used when it is not possible to directly compile required functions within the environment used to create the gateway DLL.

A variety of tools can be used to implement the engineering calculations. In recent times, Matlab/Simulink has become the de facto standard in academic circles because of its ease of use, versatility, and large library of functions.

Matlab code can also be compiled into a stand alone DLL, which can then be linked to Vensim's DLL. For computational efficiency, the code can be first translated into C and then compiled, as depicted in Figure F-1.

The combined approach enables us to enforce algebraic constraints and perform more complex mathematical calculations using the most appropriate engineering techniques. This approach is particularly useful for the transmission system.

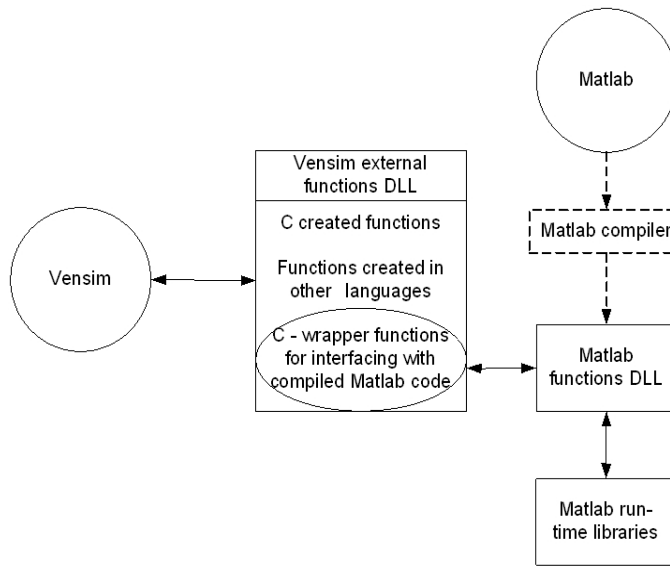

Figure F-1. Linking Matlab code in Vensim simulations.

Optimal Power Flow Calculations

Solving a problem with algebraic constraints, such as an Optimal Power Flow (OPF), in a dynamic simulation environment is inherently difficult. In a more complex case, it may be impractical. Managing algebraic constraints using a math oriented modeling approach and programming language is generally more tractable. As said earlier, we use Matlab and some of its functions from the accompanying libraries to apply more powerful methods within the Vensim environment. Still, there remain important modeling decisions. In the following, the determination of price in the different areas considering operational constraints is detailed in order to highlight the modeling choices.

Neglecting for the moment the details of the bidding and market clearing processes, assume the prices are determined by the marginal costs of the generator units. Further, assume that the generator costs are quadratic

$$C_i(P_i) = \frac{a_i}{2}P_i^2 + b_iP_i + c_i \qquad (1)$$

with P_i the generator output of unit i. Now, if no units are operating at their limits and there are no network constraints, all generators should operate at the same marginal cost, which can be found analytically as

$$\lambda = \frac{P_{Load} + \sum_i b_i / a_i}{\sum_i 1/a_i} \tag{2}$$

Optimization approaches, such as OPF, are applied by the ISO to satisfy system constraints and incorporate the market rules into operations. There are of course movements of prices at different time-scales, but these movements do not follow directly from the market rules or underlying forces. Some researchers have attempted to model the price dynamics as simple linear systems (e.g. Alvarado 1999). Unfortunately, such a modeling approach is completely unrelated to the forces that actually move prices. As such, it is difficult to set parameters appropriately. Moreover, it is not clear if such an artificial construct can provide insight. Others have shown that price movements tend to occur more as a complex switching between static models (Vucetic 2001). Such a model is more suitable for analysis of past movements rather than for causal analysis and the prediction of long-term patterns. Here, we enforce the operational constraints but do not attempt to model the daily or weekly price dynamics.

Continuing our illustration of modeling choices, the objective is to minimize the overall system cost:

$$\min_{\mathbf{P}_g} C_{\Sigma} = \sum_{i=1}^{N} C_i(P_{gi}) = \min_{\mathbf{P}_g} \left(\frac{1}{2} \mathbf{P}_g^{\mathrm{T}} \mathbf{H} \mathbf{P}_g + \mathbf{P}_g^{\mathrm{T}} \mathbf{f} \right) \tag{3}$$

subject to power balance and generators' operating limits

$$\sum_{i=1}^{N} P_{gi} = \sum_{i=1}^{n} P_{li} \,,\ \underline{P}_{gi} \le P_{gi} \le \overline{P}_{gi} \,. \tag{4}$$

The above can be solved without difficulties using, for example, quadratic programming. But it can be costly to implement in a dynamic simulation environment, especially with the additional constraints introduced by the network. These include the power flow balance for each node and the loading limits for each of the network elements. One must solve the static algebraic problem that is introduced within the main simulation loop performing the numerical integration. This slows down simulation and further, these constraints are not actually hard limits given but only an approximate operations model.

In order to address these issues, a proper choice of time is needed. We choose to represent each month by a typical daily model. Thus, the prices vary hour to hour, but they are found as a snapshot solution with no dynamics. Specifically, we solve an optimization problem over a single day horizon that respects the limits but allows for month to month dynamics as determined by external influences of supply and demand growth, hydrology, and so on.

Reduced Version of DC OPF

Addressing these issues also requires a compact representation of the transmission network. Here, we present a compact, reduced version of the DC OPF, the direct current optimum power flow calculation. (The term "direct current" can be misleading since we are dealing with an AC system. When used here, the term DC simply means that the calculation ignores the reactive power.) The standard form of the calculation can be found elsewhere (Wood 1996). Its salient feature is that it eliminates nodal voltage phase angles from consideration and explicit network equality constraints.

We start from the standard DC power flow equations that relate nodal injections, $\mathbf{P}_{inj}$, to line flows, $\mathbf{P}_{flow}$:

$$\mathbf{P}_{flow} = [P_{i-j}] = \mathbf{X}^{-1}\mathbf{A}^{\mathrm{T}}(\mathbf{B}')^{-1}\mathbf{P}_{inj} = \mathbf{D}\mathbf{P}_{inj} \tag{5}$$

where $\mathbf{X}$ is a diagonal matrix with line reactances, $\mathbf{B}'$ is the imaginary part of the bus-admittance matrix, $\mathbf{A}$ is the node-branch incidence matrix, and $\mathbf{D} = \mathbf{X}^{-1}\mathbf{A}^{\mathrm{T}}(\mathbf{B}')^{-1}$. Nodal injections are the difference between generation and load power in each node. The loads are lumped in an equivalent load, but we keep generators separate, because their outputs are the decision variables in the optimization. Standard DC formulations assume that there is only one, possibly equivalent generator per node. However, in the WECC model, a node is actually a whole area with many different generators. For this purpose, we introduce the "node-generator" incidence matrix, $\mathbf{A}_g$, with binary elements a_{gij} that specify whether generator j is connected to node i.

By breaking down nodal injections to their components, the inequality constraints imposed by the network elements' capacities, $\mathbf{P}_{cap}$, can be written as:

$$-\mathbf{P}_{cap} \leq \mathbf{P}_{flow} = \mathbf{D}(\mathbf{A}_g \mathbf{P}_g - \mathbf{P}_l) \leq \mathbf{P}_{cap} \tag{6}$$

Written in a compact form, the inequality constraints are:

$$\begin{bmatrix} \mathbf{D} \cdot \mathbf{A}_g \\ -\mathbf{D} \cdot \mathbf{A}_g \end{bmatrix} \cdot \mathbf{P}_g \leq \begin{bmatrix} \mathbf{P}_{cap} + \mathbf{D} \cdot \mathbf{P}_l \\ \mathbf{P}_{cap} - \mathbf{D} \cdot \mathbf{P}_l \end{bmatrix} \tag{7}$$

or

$$\mathbf{A}_{in} \cdot \mathbf{P}_g \leq \mathbf{b}_{in} \,. \tag{8}$$

Standard DC OPF formulations use network equations to specify power balance in each node, including the reference. Thus, a total of n equality constraints are usually specified. The corresponding Lagrange coefficients for each of these constraints then give the locational marginal prices (LMPs) for all nodes. In our formulation, we could specify the power balance in each node as:

$$\mathbf{A}\mathbf{P}_{flow} = \mathbf{P}_{inj} = \mathbf{A}_g \mathbf{P}_g - \mathbf{P}_l \tag{9}$$

but, since we have already expressed power flows in terms of injected powers in the independent nodes, the result will be a trivial set of equality constraints of the form: $0\mathbf{P}_g = 0$. The only equality constraint that we can use is the one considering the reference node and the power balance in the whole network, given by (4). For simplicity, we will not explicitly specify generators' operating limits, but it's assumed that they will be enforced. So, the Lagrangian function for our DC OPF formulation is the following:

$$L = \sum_{i=1}^{N} C_i(P_{gi}) + \lambda\left(\sum_{i=1}^{n} P_{li} - \sum_{i=1}^{N} P_{gi}\right) + \boldsymbol{\mu}^{\mathrm{T}}(\mathbf{b}_{in} - \mathbf{A}_{in} \cdot \mathbf{P}_g) \tag{10}$$

The formulation (10) can be solved with a standard routine. For the WECC model, we use Matlab's "quadprog" function. The solution is obtained relatively fast, although there is overhead in the calling procedure between Vensim's and Matlab's DLLs. Nevertheless, even this approach can be prohibitively slow if the time resolution is very high. Our current model uses a typical day to represent prices and costs for each month of the year. The model is normally used to simulate the WECC from 2005 to 2025. The entire simulation requires 240 steps, one for each month of the study interval. With this time resolution, the model can be simulated with the quick response needed for rapid experimentation that is useful for group learning.

From (10), after solving for Karush-Kuhn-Tucker optimality conditions, we find the following for the LMPs:

$$\begin{aligned} LMP_1 &= \lambda \\ [LMP]_{[2\ldots n]} &= \lambda + \left[\mathbf{D}^{\mathrm{T}} \;\middle|\; -\mathbf{D}^{\mathrm{T}}\right]\boldsymbol{\mu} \end{aligned} \tag{11}$$

This analysis leaves us with four important conclusions on the locational marginal prices:

- The LMP at the reference node is given by λ, as the power flows don't depend on the injection in this node.
- For all the other nodes, the corresponding *LMP*s have to be adjusted for all congestion that appears in the network. These adjustments are done by multiplying the Lagrange coefficients for the congested lines with the sensitivities of the flows in those lines from the injection at the given node.
- In the special case when there are no congested lines, all LMPs are equal to λ.
- If there are congested lines, even a single one, all nodes in the system in general will have different prices due to different sensitivities (Christie 2000).

Approximate Representation of The Transmission System

We explain in the next appendix that the WECC model is simplified as 7 areas interconnected by 10 transmission lines. The large areas and the small number of lines means that errors will be introduced in implementing the DC OPF calculation. The errors are the inevitable result of approximating the power network in a highly aggregated manner. Power systems are nonlinear and reduction process very often involves multiple linearizations. Thus, the obtained equivalent system is valid within a region whose boundaries may be difficult to determine.

Since the accuracy of the equivalent calculations is hard to verify, we elect to pursue a different approach. We begin with a detailed representation of the entire WECC network comprised of 13,090 busses (nodes), 11,884 lines, and 5,159 transformers. This representation is used to estimate power flows on all lines in a collection of test conditions. We then add the flows to get the aggregate flows along the ten lines shown in the next appendix. We add the generations in each area, and we substract the loads in each area. This provides aggregate injections in each of the seven areas. We then use a least squares routine to estimate the slopes of a hyperplane that will explain the ten power flows as a function of the seven injections. The hyperplane is comprised of 70 slopes, and these slopes correspond to the elements in the sensitivity matrix **D** shown previously in (6).

We believe this statistical approach is more suitable for the WECC model because it is based on the DC OPF formulation explained above, and it avoids the need to estimate reactances for the aggregate lines. We do need to specify $\mathbf{P}_{cap}$, the capacity of the equivalent transmission lines. These are based on the available transmission capabilities (ATCs) for the transmission paths that correspond to these lines, as explained in the next appendix.

Appendix G. Transmission Capacity

The best source of information on the loads and resources in the western system is provided by the WECC. Readers familiar with their information summaries will be accustomed to seeing the four areas in Figure G-1. Area 1 is the NWPP, the Northwest Power Pool. It has the largest geographical area, the largest energy loads and most of the region's hydro generation. Area II is the Rocky Mountain Power area, the smallest of the four areas. Area III is the southwest area, which includes Arizona, New Mexico and southern Nevada. The final area in the summary reports is California and the northern tip of Mexico. The WECC summaries provide good starting point for the data needed in a simulation model, and the previous model (Appendix A) was organized around these four areas. However, for the analysis to be conducted with the new model, it makes sense to create smaller areas This is especially

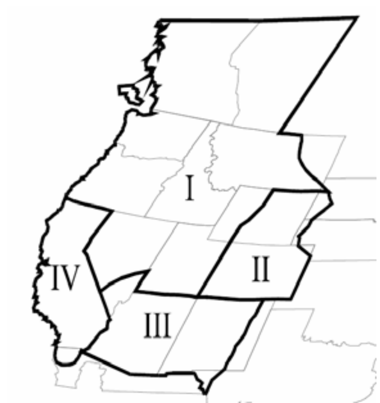

Fig. G-1.WECC Areas.

important for the Northwest Power Pool which spans 7 states and 2 provinces. By simulating more areas, we provide a more informative analysis of policies which often differ between states and between the USA and Canada. However, as more areas are added, data support and model checking becomes much more burdensome. For our purposes, a useful approach is to break the WECC down into seven areas depicted in Figure G-2. This breakdown allows for separate treatment of the loads and resources in the Canadian provinces. The diagram highlights WA/OR/CA in green since these are the states in the West Coast Governors' Initiative on curbing carbon emissions.

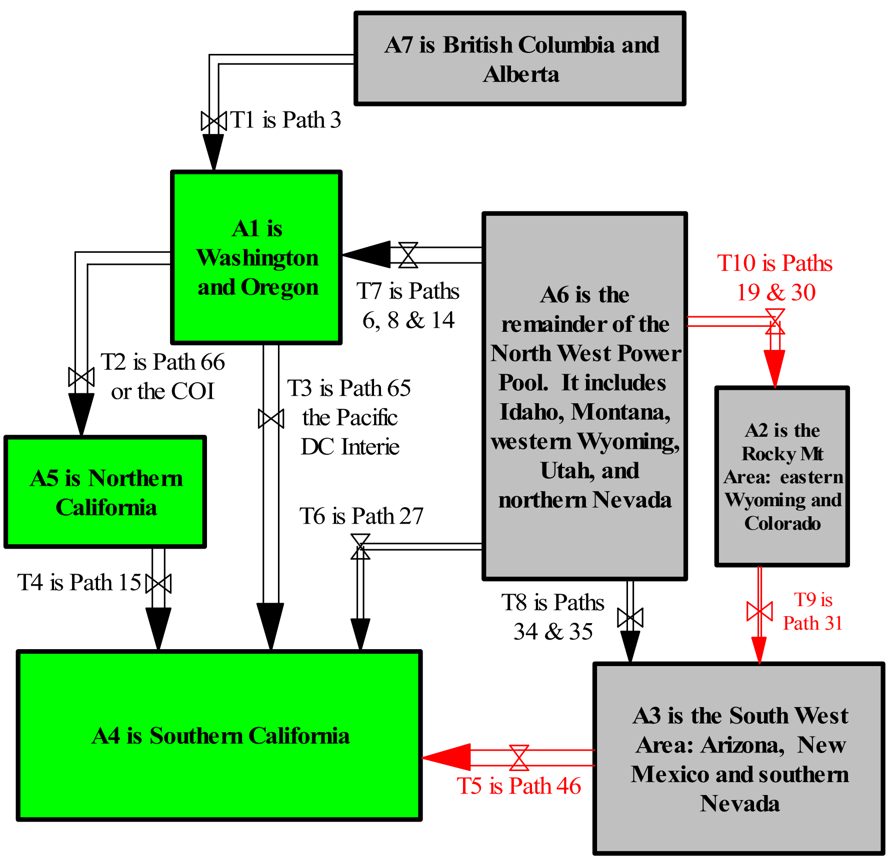

Figure G-2. Areas and transmission connections in the model.

Figure G-2 shows the ten transmission lines to be simulated in the model. We expect the power to flow primarily from north to south and from east to west in the WECC. The arrows in Figure G-2 denote the primary directions. The transmission lines are numbered T1 to T10 for ease of simulation. Readers familiar with the WECC system will be accustomed to "path" designations of the primary transmission lines. Path 15 is well known in California, for example, because the CAISO (2002A, p. 31; 2002B, p. 50) has determined that there is an "economic" need to expand the capacity between northern and southern California. The model breaks California down into two areas in case the model would be used in the future to study congestion on Path 15. This breakdown is also useful if the model is to be used to study the impact of nitrogen oxide policies in the south coast air shed.

Tie Line	WECC Paths	Primary Direction	ATC in the Primary Direction	ATC in the Opposite Direction	Comments
1	3	N to S	3.150 GW	2.000 GW	
2	66	N to S	4.800 GW	3.675 GW	COI: the CA/OR Intertie
3	65	N to S	3.100 GW	2.200 GW	Pacific DC Intertie
4	15	N to S	3.900 GW	5.400 GW	subject of several studies
5	46	E to W	10.118 GW	10.118 GW	thermal limited
6	27	N to S	1.920 GW	1.400 GW	IPP intertie
7	6, 8, 14	E to W	8.636 GW	6.400 GW	
8	34, 35	N to S	1.080 GW	1.150 GW	
9	31	N to S	0.690 GW	0.690 GW	thermal limited
10	19, 30	N to S	2.850 GW	2.850 GW	thermal limited

Table G-1. Available Transmission Capacity (ATC) for the ten tie lines simulated in the model.

Table G-I lists the ten tie lines along with their path designation in WECC reports. The Available Transmission Capability (ATC) for all lines in the system are estimated by the Independent System Operator and are commonly available on the web. We add the ATCs for the many lines to give the ATC for each of the ten lines in Table G-1.

Most of the tie lines in the west extend over long distances, and their ATC is typically limited by concerns over stability. For these lines, the ATC can differ depending on whether the power is flowing in the primary direction or the opposite direction. Two of the large lines connect the hydro-rich area of WA/OR with California. Line T2 is path 66, the California/Oregon Intertie with 4.8 GW of capacity in the southern direction. Line T3 is path 65, the Pacific DC Intertie with 3.1 GW of capacity in the southern direction.

Three of the lines in Fig. G-2 are shaded in red to remind us that they operate differently. Their ATC is more likely to be limited by thermal constraints, so the capacity will be the same in both directions. The largest of these lines is T5 which corresponds to path 46. It connects the southwest to southern California with over 10 GW of ATC.

Appendix H. Suggestions for Additional Research

This is a draft paper which will be circulated for comments from readers interested in (1) the methods for long-term simulation of large scale power systems and (2) the implementation of markets for carbon allowances. We hope readers will provide suggestions for productive lines of further research. At this stage, we are particularly interested in further research in four areas:

Higher Costs of Wind and Biomass

The S139 simulations show substantial investment in wind and biomass generation. These investments appear even though we adopt the conservative assumption that investors will face substantially higher costs as they turn to less attractive sites for wind farms and tree farms. Further work would be useful to refine the estimates of these costs and to simulate the actual spending. If, as an example, the extra cost associated with wind capacity goes for construction and operation of CTs, these extra CTs could be added to the model.

Additional Measures of Adequacy of Capacity

The current model operates with a general target of 15% reserve margin, measured with the hydro system subject to “critical” conditions. With the large generation from a stochastic resource like wind, it will be useful to add additional measures of adequacy. This is especially true in S139 simulations where wind provides a substantial share of total generation. A probabilistic approach is required to find the new target for reserve margin that will maintain the required level of adequacy. For this purpose, we could enhance the model by calculating the Loss of Load Expectation (LOLE) and Energy not Served (ENS).

Land Needs for Biomass

The S139 scenarios show a major investment in biomass-fueled power plants. In the first scenario, there is over 24 GW of biomass capacity by the year 2025. These 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 (Flynn and Ford 2005). Using round numbers, one might 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 devoted to dedicated crops such as hybrid poplars. It is useful to expand the model 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. Development of biofuels is a high priority in the State of Washington, and Senator Cantwell (2005) has introduced the *20/20 Biofuels Challenge Act*.

Steady Construction or Boom and Bust?

Our final suggestion returns to the boom and bust pattern, the focus of previous modeling at WSU (Ford 2002). For the purpose of this paper, we adopted the optimistic assumption that power plant construction would occur in a steady, timely manner as needed to allow growth in electricity supply to keep pace with demand. This “keeping pace” assumption makes sense if distribution companies are encouraged to engage in integrated resource planning and to sign the long-term contracts even though the cost of new power plants may exceed the average prices in the wholesale market. However, it is possible that the western system could see a rerun of the boom/bust pattern from 1998 – 2005. This pattern has the unfortunate impact of leaving the system vulnerable to price spikes and blackouts during some years. It then leaves merchant investors vulnerable to bankruptcy in the following years.

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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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(http://www.mathworks.com/products/simulink/)

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The *STELLA* software is provided by isee systems, formerly known as High Performance Systems.
The software and users guides are available at
http://www.iseesystems.com/

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The *Vensim* software is provided by Ventana Systems, Inc.
The software and users guides are available at
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