NATIONAL ENERGY TECHNOLOGY LABORATORY

An Analysis of the Effects of Drought Conditions on Electric Power Generation in the Western United States

April 2009

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DISCLAIMER

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1 BACKGROUND

This report was funded by the U.S. Department of Energy's (DOE's) National Energy Technology Laboratory (NETL) Existing Plants Research Program. The energy-water research component of this program is focused on water use at power plants. This study complements the program's overall research effort by evaluating the availability of water at power plants under drought conditions.

During the summer and fall of 2007, a serious drought affected the southeastern United States. River flows decreased, and water levels in lakes and other impoundments dropped. In a few cases, water levels were so low that power production had to be stopped or reduced. It is likely that, in coming years, competing water demands will increase. It is also possible that climatic conditions will become warmer or at least more variable, thereby exacerbating future droughts.

This report attempts to identify the system-wide impacts on the power system that could arise from various decreases in surface water levels. Our analysis is based on a separate report by Kimmell and Veil (Kimmell and Veil 2009) that (1) evaluates the sources of cooling water used by the U.S. steam-electric power plant fleet, (2) develops a database of cooling water intake locations and depths for those plants that use surface water supplies, and (3) identifies steam-electric power plants equipped with cooling water intakes that could not function if the water levels were to drop below certain thresholds. The goal of the simulations is to quantify the impacts of such water level decreases on the generation mix, future electricity prices, and carbon dioxide (CO_2) emissions that would occur if the utility and system operators were forced to take any of those steam-electric plants out of service, or reduce their outputs, for extended periods of time.

Our analysis focuses on the Western United States. We calibrate our power system dispatch model to the year 2006 and then develop projections for future years. In this document, we report results for 2010, 2015, and 2020.

2 METHODOLOGY AND ASSUMPTION

2.1 Scope and Model Resolution

We estimate future generation mix, future electricity prices, and CO_2 emissions by simulating the operations of thermal and renewable power plants in the Western Electricity Coordinating Council (WECC) system, particularly the portion of WECC that is within the United States (Figure 1). The WECC regions that we model include the Northwest Power Pool (NWPP), Rocky Mountain Power Area (RMPA), Arizona-New Mexico-Southern Nevada Power Area (AZNM), and California (CAL). We pay special attention to interdependencies among hydropower and thermal power plant operations because hydropower plants may provide up to 40% of the WECC load during years when wet hydrological conditions occur. In some water basins, such as the Colorado River System, annual hydropower generation can vary by more than a factor of five (Figure 2). Hydrology conditions affect the dispatch of the thermal system, and therefore, water use by the power sector.

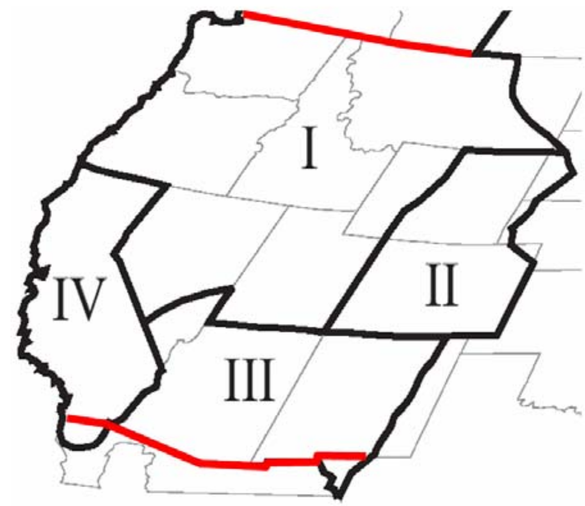

Figure 1: Map of WECC system (Only United States Considered for Modeling)

Hydropower plant generation is determined on an hourly time step. In the current model implementation, we simulate hydropower as an aggregate generation resource that serves both base load and peaking duties. We compile the information for the aggregation from individual plant-level data. The hourly dispatch of the aggregate power plant is based on (1) monthly generation control totals, (2) the amount of water used for base duties, (3) estimated monthly hydropower capability, and (4) a WECC-wide hourly load profile.

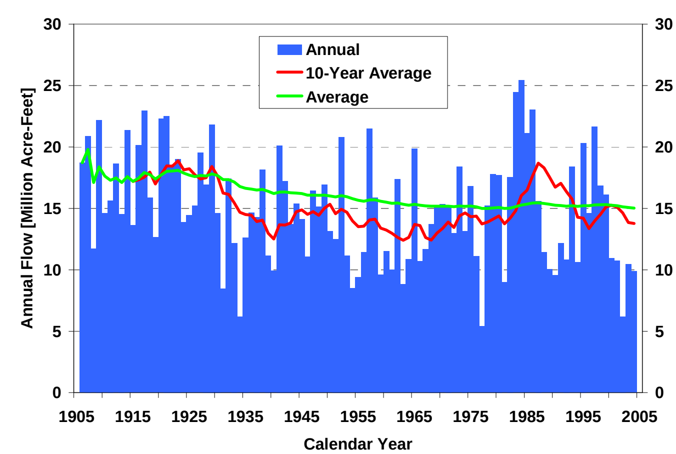

Figure 2: Example for Hydro Variability — Natural Flow for the Colorado River at Lees Ferry

For electricity demand, we construct WECC-wide hourly electricity demand profiles for 2006 to 2020 from control area load profiles in combination with forecasts from the *Annual Energy Outlook 2008* (AEO 2008) published by DOE's Energy Information Administration (EIA 2008[a]).

Thermal power plants are simulated at the unit level. We employ a probabilistic dispatch model to simulate thermal power plant production to meet load that is not served by hydropower plants and other renewable resources, such as wind power. We can run the thermal dispatch in two modes: by either using monthly load duration curves (LDCs) or using hourly chronological loads. In the first mode, we obtain monthly average capacity factors, generation levels, and monthly price distributions. In the second mode, we obtain hourly price distributions. In both modes, maintenance and random forced outages are accounted for at the unit level.

2.2 Analytical Process

We model the WECC–U.S. system dynamically for 2006–2020 using several modeling tools. The methodology employs the following sequence of operations:

- Collect and process data and information;
- Determine hourly renewable generation, including dispatchable and non-dispatchable aggregate hydropower and other non-dispatchable plants, such as wind;
- Determine current hourly electricity loads and forecast future load levels;
- Adjust loads for non-dispatchable renewable generation and hydropower plant generation;
- Develop baseline capacity expansion plan until 2020;
- Run a probabilistic thermal dispatch model to estimate electricity generation by thermal generation units from 2006 to 2020;
- Compute hourly prices chronologically and calculate monthly price distributions;
- Develop alternative drought scenarios;
- Run probabilistic dispatch model for the different scenarios to project hourly prices until 2020; and
- Compare and summarize results.

2.3 Data Collection and Preparation

The baseline analysis utilizes an extensive set of information. We compile the underlying data from various sources; considerable effort is spent on data validation to ensure data consistency. The following is a list of information sources used to compile the WECC-wide inventory of existing and proposed power plants, hourly load profiles, load projections, fuel price projections, and technology data.

2.3.1 Inventory of Existing and Proposed Power Plants

- Form EIA-860 (*Annual Electric Generator Report*) (EIA undated[a])
  - Identifies the generator location
  - Identifies the generator owner(s)
  - Provides information on summer and winter generating capability
  - Identifies the type of primary mover
  - Identifies the fuel type(s) used by the generator

- Form EIA-423 (*Monthly Cost and Quality of Fuels Report*) (EIA undated[a])
  - Provides information on the price of the fuel(s) used by generator
  - Provides information on the sources of the fuel(s) used by the generator
  - Provides information on the quality of the fuel(s) used by the generator (e.g., sulfur content, ash content, and higher heating value)

- Form EIA-906 (*Power Plant Report*) (EIA undated[a])
  - Provides information on monthly fuel consumptions by generator
  - Provides information on monthly generation levels by generator

- North American Electric Reliability Corporation (NERC) *Generator Availability Data Set (GADS)* (NERC 2008)
  - Provides scheduled maintenance outage rates by type of technology
  - Provides random outages by type of technology

2.3.2 Historical Load Data

- Federal Energy Regulatory Commission (FERC) Form 714 (*Annual Electric Balancing Authority Area and Planning Area Report*) (FERC 2009)
  - Provides information on hourly load data by control area

2.3.3 Load Projections

- WECC near-term forecast (*Summary of Estimated Loads and Resources*) (WECC 2007[b]) and FERC Form 714 (FERC 2009)
  - Provides information on monthly loads for two years into the future
  - Provides information on seasonal loads for 3- to 10-year forecast period

- AEO 2008 (EIA 2008[a])
  - Provides annual load projections until 2030

2.3.4 Fuel Price Projections

- AEO 2008 (EIA 2008[a]) projections
  - Provides annual fuel price escalations by fuel type until 2030

2.3.5 Expansion Candidate Technology Data

- AEO 2008 (EIA 2008[a])
  - Provides information on technical and economic performance parameters of representative power generation technologies

2.4 Treatment of Renewable Generation (Hydro and Wind)

We first estimate non-dispatchable renewable power generation. From the detailed output tables for the AEO 2008 reference case, we take the annual energy generation by renewable technology until 2020 for the three regions used by EIA to define WECC (Note: EIA divides the U.S. into 13 regions and three of those regions make up WECC, while WECC subdivides itself into four regions. EIA combines the WECC regions of AZNM and RMPA into one region, called RMPA-AZ. See Figure 10 in Section 2.7 for details). Geothermal, municipal solid waste, and wood and biomass combustion units are included in the dispatch model. For wind, we use a total of eight available wind generation patterns for the Western United States and assign them as representative wind patterns to each of the three EIA-defined regions that make up WECC to obtain hourly wind generation patterns for each WECC region. We use a scaling routine to match the AEO 2008 regional wind energy totals and sum across the regions to obtain a WECC-wide hourly wind generation trace until 2020 (Figure 3 shows Base Case WECC wind generation in 2006). This wind generation is then subtracted from the total WECC load. We complete a similar load subtraction for non-dispatchable hydropower (i.e., run-of-river power plants). Section 2.6 provides more details about the load subtraction process.

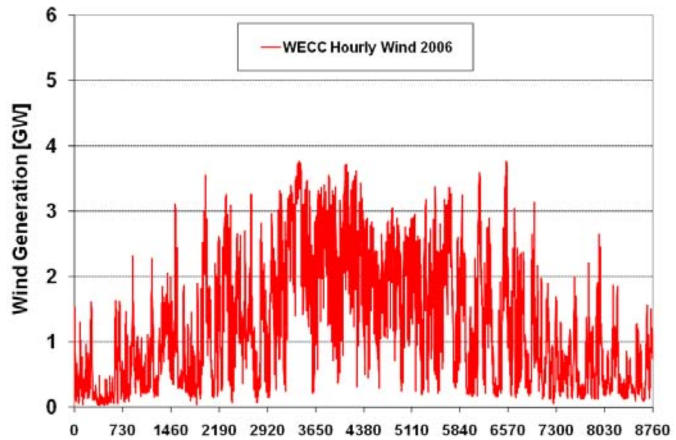

Figure 3: WECC Hourly Wind Generation 2006

To model the hourly generation pattern from dispatchable hydropower plants (plants with reservoirs or storage capabilities), we use a peak shaving approach. By using information from Form EIA-906, we estimate monthly hydropower generation patterns for individual hydropower plants. Also, data from various sources are used to separate power plant capabilities obtained from Form EIA-860 into base load and peaking duties. Total monthly hydropower generation levels and plant capabilities are then computed. Next, we simulate the hourly hydropower dispatch by using a peak shaving algorithm that minimizes the peak load that the thermal system must serve subject to monthly hydropower capacity and energy constraints, spinning reserve duties, hourly ramping constraints, and daily change limitations (Figure 4).

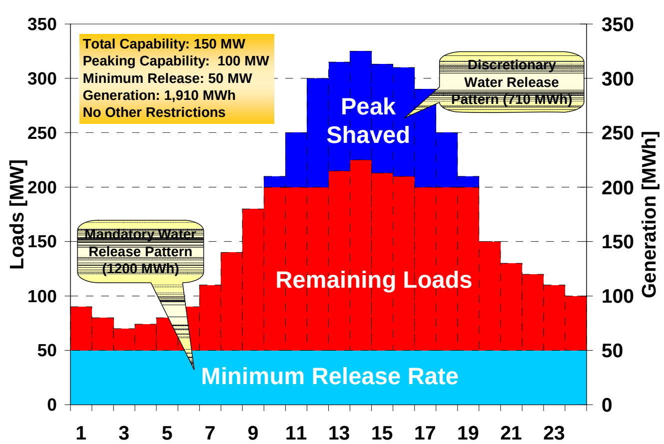

Figure 4: Hydropower Plant Operations

2.5 Current Load and Load Forecast

Figure 5 shows the process used to develop the hourly WECC load data for the analysis period (2006–2020). First, we collect hourly historical load data for all control areas in the United States

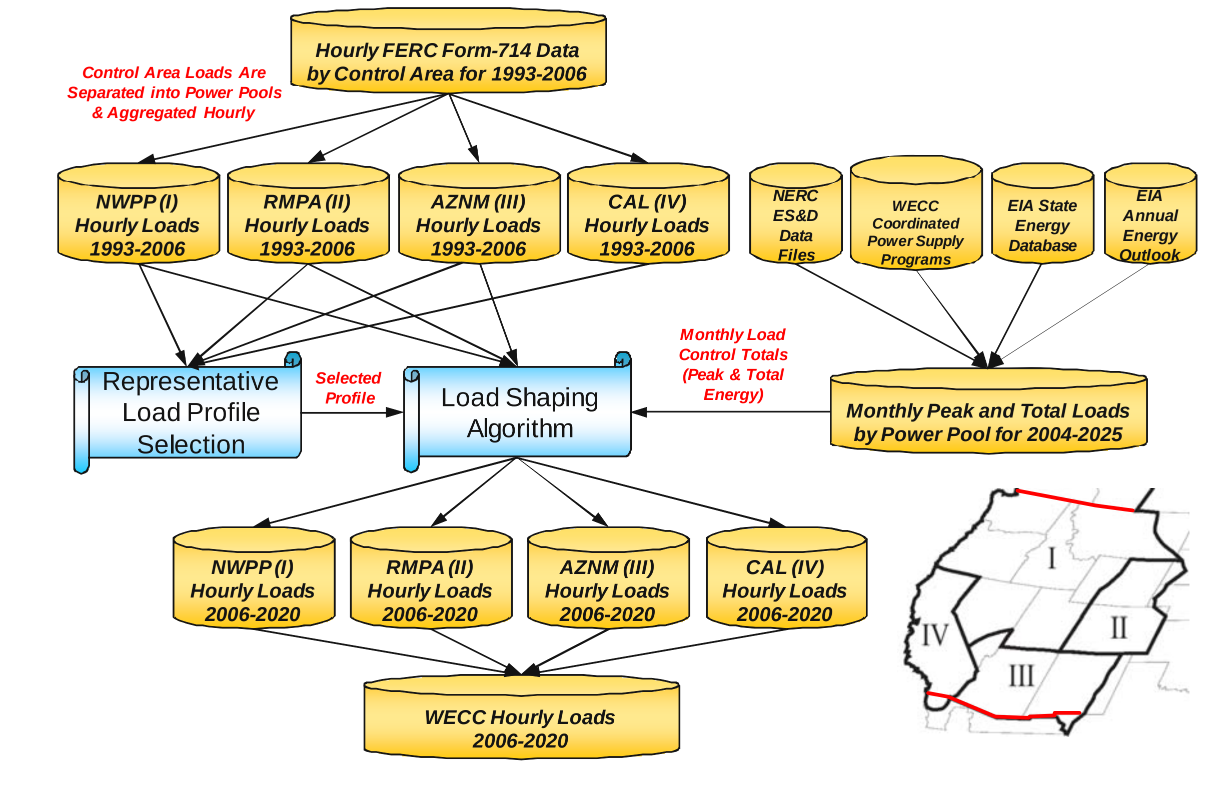

Figure 5: Processing Hourly Loads

that report to WECC. We perform consistency checks on the data, making adjustments when errors are found and data are missing. Control area loads are then grouped and aggregated into the four WECC regions: NWPP, RMPA, AZNM, and CAL. The areas only cover U.S. territory. Next, we use a load-scaling algorithm to adjust aggregated hourly load profiles to exactly match the monthly peak and total load values reported for each WECC region.

Figures 6 and 7 show relative monthly energy factors and monthly relative peak fractions based on FERC Form 714 for two of the major areas (RMPA and AZNM) for a selection of historical years. For each major area, we select from this data set, as the representative load profile, the data set that has the lowest sum of squared differences relative to the average profile. This representative profile is used as the basis for constructing hourly load projections for future years through 2020. The load-scaling algorithm is applied to adjust the representative hourly load profiles to match peak and total load targets that come from various statistics, including WECC's coordinated power supply programs, EIA state energy databases, EIA's AEO 2008, and the Electricity Supply and Demand (ES&D) data from the NERC.

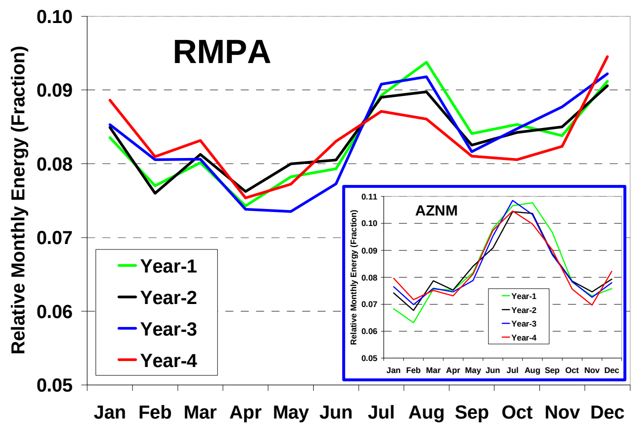

Figure 6: RMPA and AZNM Monthly Energy Factors

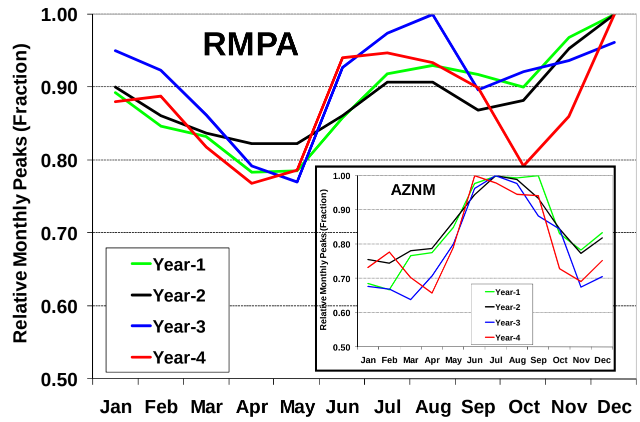

Figure 7: RMPA and AZNM Monthly Peak Factors

2.6 Load Adjustments

As discussed in Section 2.4, the original hourly total-WECC load data series are adjusted in two ways:

1. For non-dispatchable resources (e.g., wind, run-of-river hydro) by using load subtraction.
2. For dispatchable hydropower using the peak shaving algorithm.

The remaining adjusted hourly loads are used to construct monthly LDCs that are served by the thermal system and are input into the probabilistic thermal dispatch model for the simulations. Figure 8 shows a 1-week example of how the load adjustments affect the total load served by the thermal system. Figure 9 shows the monthly load duration curves.

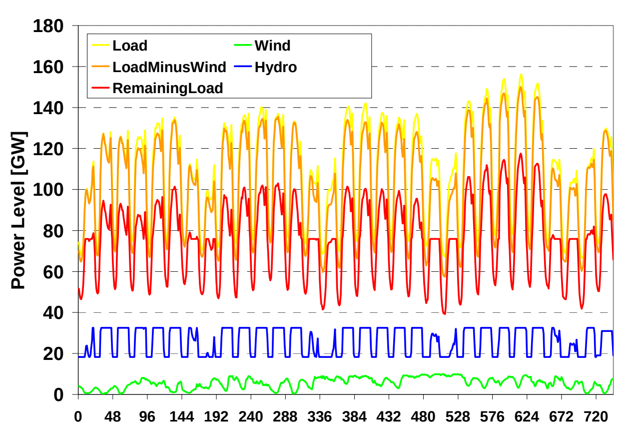

Figure 8: Example for Load Adjustment (WECC May 2020)

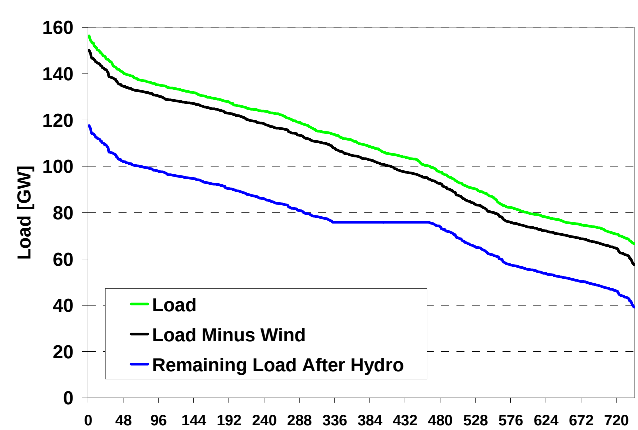

Figure 9: Example for Load Duration Curves (WECC May 2020)

2.7 Capacity Expansion Modeling

We develop the baseline capacity expansion scenario for the WECC system until 2020 by using the EIA's AEO 2008 as a starting point. EIA derives these projections by using the National Energy Modeling System (NEMS) Electricity Market Module (EMM). On the basis of the fuel prices and electricity demands provided by other modules of the NEMS, the EMM determines the most economical way to supply electricity, subject to environmental and operational constraints. A detailed description of the EMM is available in *Electricity Market Module of the National Energy Modeling System 2006* (EIA 2006).

The AEO 2008 contains projections of new capacity additions by technology for a total of 13 regions, shown in Figure 10.

Three of these regions represent a geographic area in the United States that is served by WECC:

- Region 11: Northwest Power Pool
- Region 12: Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada
- Region 13: California

It should be noted that WECC defines four general load areas or regions within its service territory:

1. Northwest Power Pool Area
2. Rocky Mountain Power Area
3. Arizona – New Mexico – Southern Nevada Power Area
4. California – Mexico Power Area

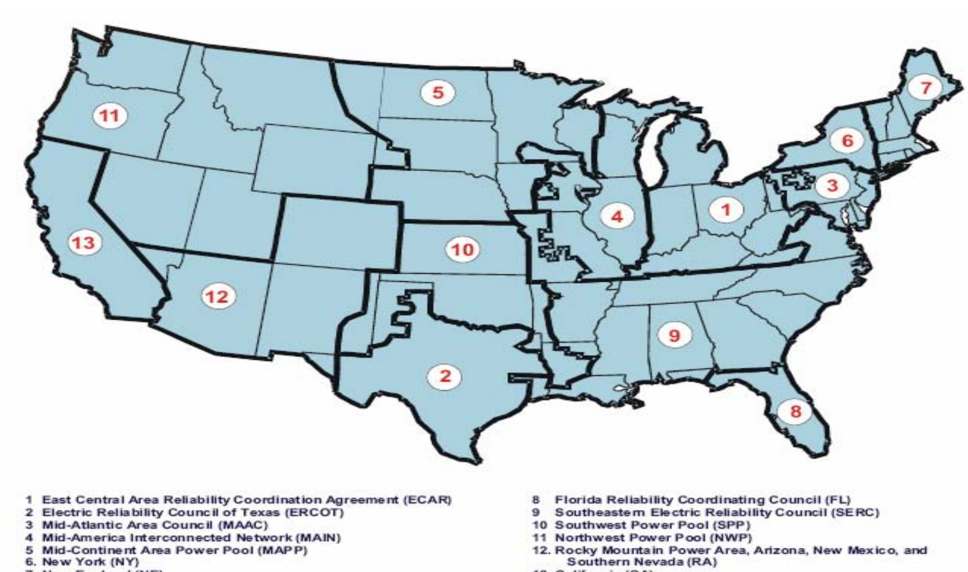

Figure 10: Annual Energy Outlook 2008 Electricity Market Model Supply Regions (Source: EIA 2008[b])

To maintain consistency with the AEO 2008, our analysis uses a representation of the WECC system with three regions for the development of the revised capacity expansion plan.

Figure 11 shows the AEO 2008 peak load forecasts for each of the WECC regions. These load forecasts are used to determine the needs for additional capacity until 2020.

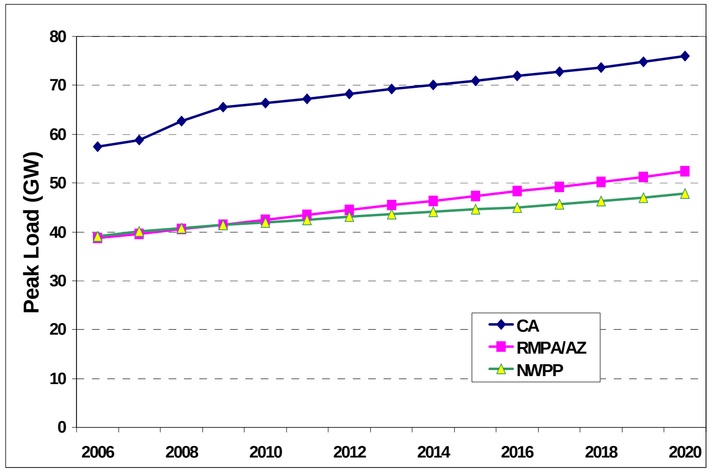

Figure 11: Annual Peak Load Forecasts until 2020

The EMM analysis for the AEO 2008 considers a number of different candidate generating technologies. As shown in Table 1, they include both conventional and renewable technologies. The EMM analysis also allows for changing and improving technical and economic parameters over time (i.e., learning parameters).

Table 1: Generating Technologies Represented in the Electricity Market Module (Source: EIA 2008[b])

Capacity Type
Existing coal steam plants
High sulfur pulverized coal with wet flue gas desulfurization
Advance coal - integrated coal gasification combine cycle
Advanced coal with carbon sequestration
Oil/gas steam - oil/gas steam turbine
Combined cycle - conventional gas/oil combined cycle combustion turbine
Advanced combined cycle - advanced gas/oil combined cycle combustion turbine
Advanced combined cycle with carbon sequestration
Combustion turbine - conventional combustion turbine
Advanced combustion turbine - steam injected gas turbine
Molten carbonate fuel cell
Conventional nuclear
Advanced nuclear - advanced light water reactor
Generic distributed generation - baseload
Generic distributed generation - peak
Conventional hydropower - hydraulic turbine
Pumped storage - hydraulic turbine reversible
Geothermal
Municipal solid waste
Biomass - integrated gasification combined cycle
Solar thermal - central receiver
Solar photovoltaic - single axis flat plate
Wind

On the basis of the revised demand forecast for the WECC regions, we use a planning reserve margin of 15% as a driver for new capacity additions until 2020. As stated in the *WECC 2007 Power Supply Assessment* (WECC 2007[a]), the capacity needs are determined at the level of WECC regions, and each region needs to maintain a minimum planning reserve margin of 15%. Because the reserve margin requirement is normally based on the net available capacity, while the AEO 2008 lists only installed capacities, we have increased the requirement for the NWPP region to 25% of installed capacity to account for the large amount of hydro capacity in this region. The reserve margin requirements for the other two regions, RMPA/AZ and CAL, remain at 15%. We then perform an expansion analysis for each region individually. Therefore, the total capacity additions for the WECC system are obtained as the sum of new capacity additions in each of the regions. The overall resulting reserve margin, based on the installed capacity, for the WECC system as a whole, amounts to about 25% in 2012, gradually decreasing to about 21.4% in 2020.

The technology mix of new generating capacity until 2020 is based on the AEO 2008 projections for each WECC region. Compared with the AEO 2008 expansion plan, the 25% planning reserve margin requirement does not produce any changes in the capacity needs for the NWPP region, while the 15% reserve margin requirement requires some new generating capacity to be added to the system in addition to that already projected by the AEO 2008. For the RMPA/AZ region, this results in only slightly increased capacity needs beginning in 2019 and amounting to a cumulative total of 1,160 MW by 2020. For the CAL region, the 15% reserve margin requirement results in additional capacity needs beginning in 2012 and amounting to a cumulative total of 9,850 MW by 2020. Again, it is assumed that the technology mix for this additional capacity corresponds to that of the AEO 2008.

2.8 Thermal Dispatch Modeling

The first step in the dispatch modeling is to create a validated unit inventory for the entire WECC system. As shown in Figure 12, we use Form EIA-860 as a starting point, Form EIA-423 to add fuel data to the inventory, Form EIA-906 to obtain estimates for heat rates, the GADS database on outage information, and the AEO 2008 tables for variable operation and maintenance (O&M) costs.

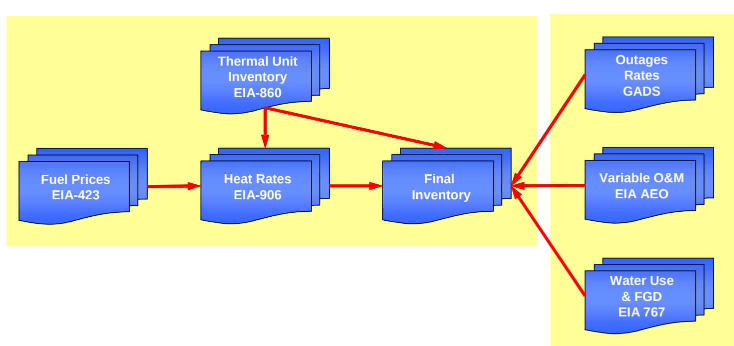

Figure 12: Creating a Thermal Unit Inventory

With the complete unit inventory, we run a unit-level hourly thermal probabilistic dispatch model that accounts for forced outages, as well as scheduled maintenance. We estimate future maintenance schedules by using a routine that maximizes the minimum reserve margin. Figure 13 shows sample results for the maintenance scheduler in combination with a forced

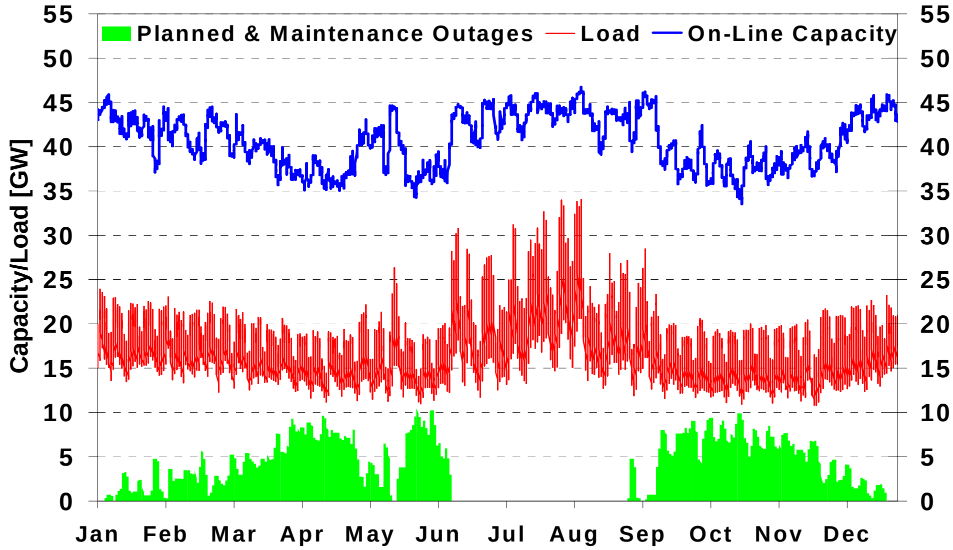

Figure 13: Example for Results of Maintenance Scheduling Routine

outage scenario. The dispatch model utilizes a convolution process in which the loads that a unit serves include (1) the original LDC and (2) loads that could not be served by units loaded before it because of forced outages.

From the dispatch routine, we obtain unit-level generation levels, chronological prices, price distributions, and CO_2 emissions and summarize them for each simulation month. Hydropower plants in this analysis are modeled as an aggregate generation resource that serves base load and peaking duties. The hourly dispatch of the aggregate power plant is based on monthly generation control totals, the amount of water used for base load duties, estimated monthly hydropower capability, and a WECC-wide hourly load profile.

3 MODEL RESULTS

3.1 Base Year Model Calibration

We use information for 2006 to calibrate the model to actual observed WECC market data. Table 2 provides a comparison of model results with actual annual generation and fuel consumption data by fuel type.

Table 2: 2006 Model Calibration for Generation Mix

Technology	Model Generation Mix (%)	Actual Generation Mix (%)
Coal	31.5	31.2
Gas	26.2	25.6
Nuclear	10.4	9.4
Hydro	28.1	28.8
Wind	1.6	1.4
Others	2.2	3.6
Total	100	100
Note: Actual generation mix is calculated based on AEO 2008.		

In addition to generation and fuel consumption levels, we test and calibrate the model with regard to historical prices, collecting prices from the following hubs in WECC for several historical years: Palo Verde, Pinnacle Peak, 4Corners, Mona, Mead, COB, NP15, SP15, MidColumbia, NOB, and WestWing. Prices are available in off-peak and on-peak blocks. We adjust the data set to account for the fact that off-peak prices are for 8-hour blocks, on-peak prices are for 16-hour blocks, and prices on Sundays are for 24-hour blocks. WECC system holidays are considered off-peak. From the hub prices, we calculate an average WECC system price that we compare with our modeled unconstrained system marginal price. Figures 14 through 17 show the results of the calibration process. The red bars show the price probability distributions from our model runs for each month in 2006. The blue lines show the monthly probability distribution of the estimated average WECC system price derived from daily hub prices for 2006.

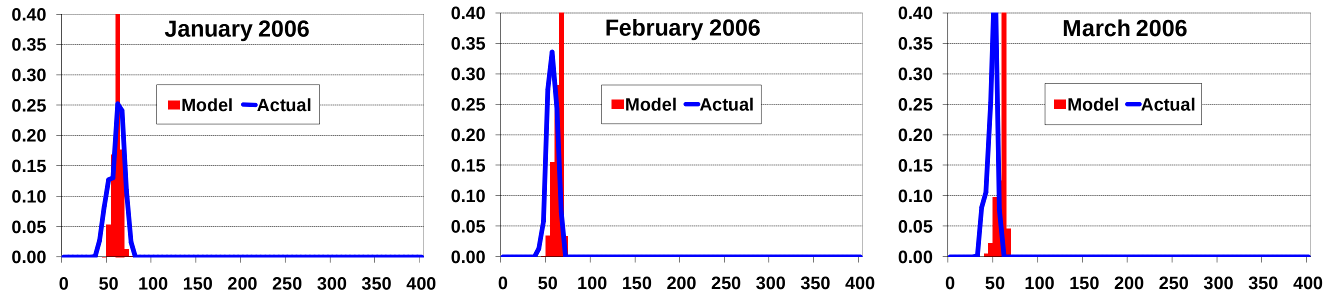

Figure 14: Model Calibration — Price Probability Distributions for January through March 2006

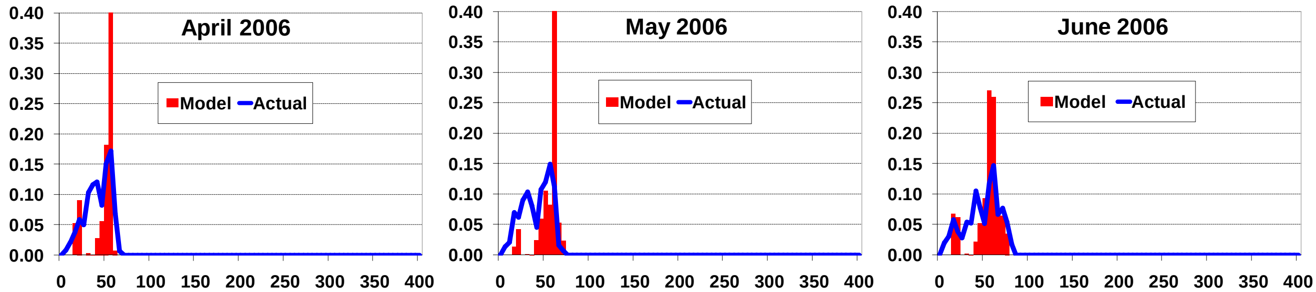

Figure 15: Model Calibration — Price Probability Distributions for April to June 2006

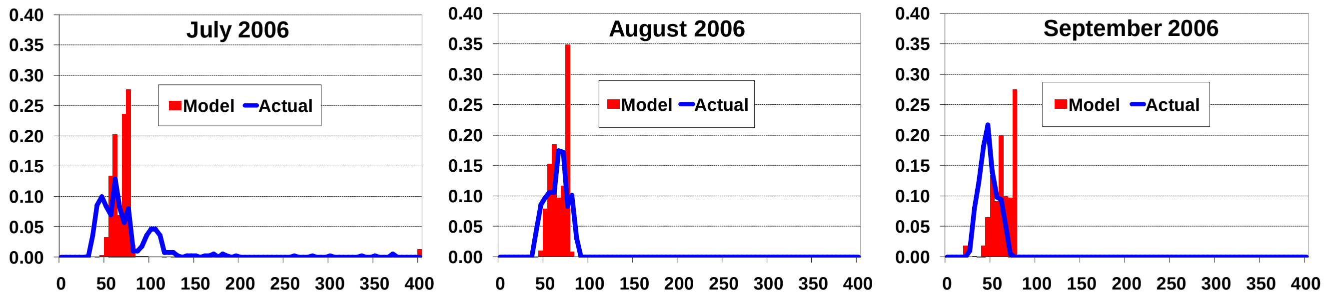

Figure 16: Model Calibration — Price Probability Distributions for July to September 2006

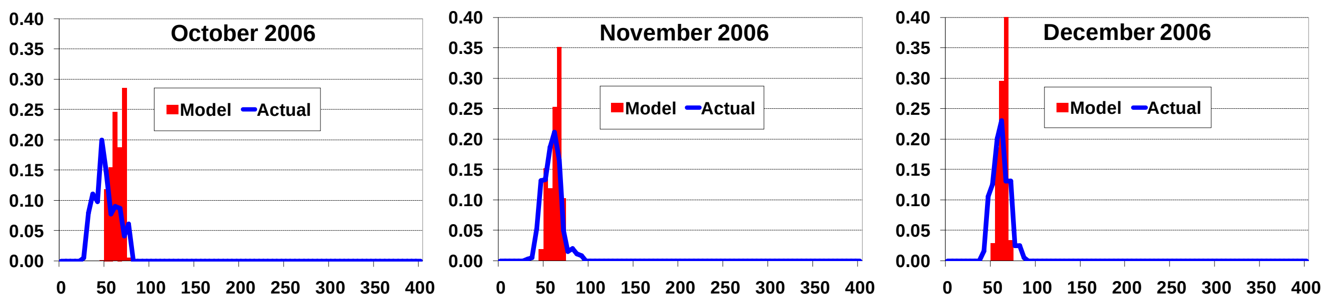

Figure 17: Model Calibration — Price Probability Distributions for October to December 2006

3.2 Baseline Results

3.2.1 Load Projection

We project that electricity demand in the WECC–U.S. system will increase from about 700 TWh in 2006 to over 930 TWh in 2020 with a corresponding growth in peak load — from over 135 GW to almost 170 GW over the same period. With this growth in load, the expected retirement of approximately 7.8 GW of existing generating units, and the need to maintain an adequate planning reserve margin, we foresee a need to bring online new capacity on the order of

50 GW by 2020. Figure 18 shows the capacity-load balance for the WECC system, illustrating the development of existing and new generating capacity versus the peak load until 2020.

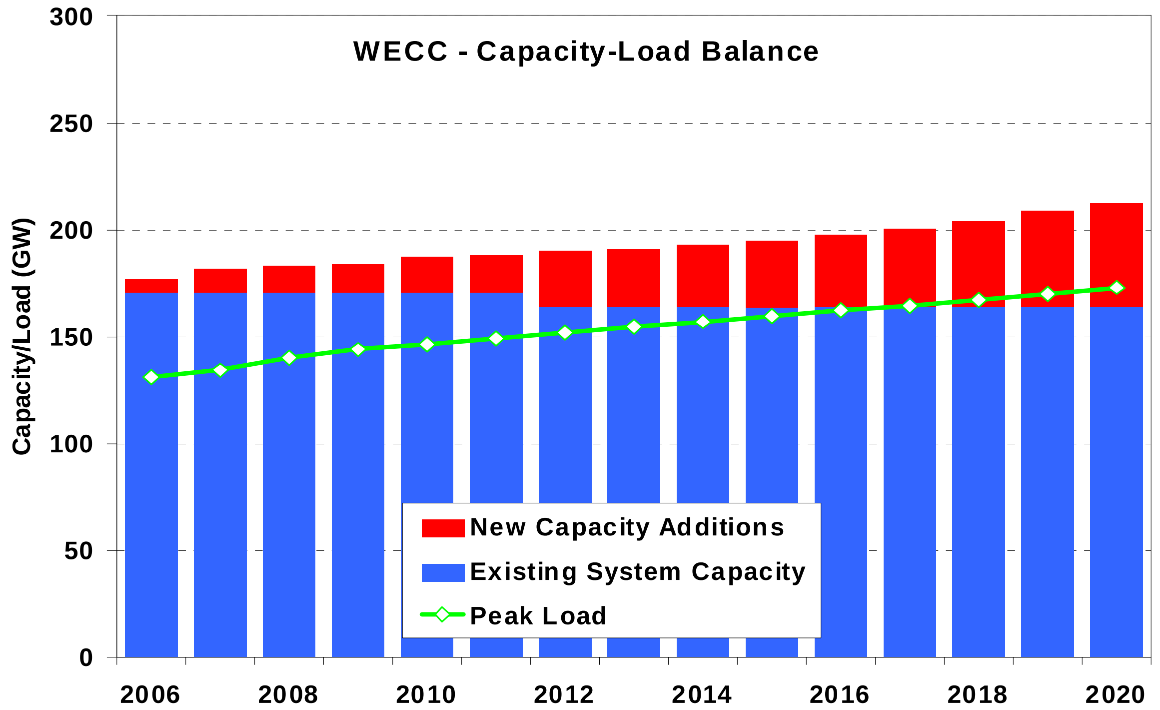

Figure 18: Baseline Projected Load, Existing System, and New Capacity Additions until 2020

3.2.2 Capacity and Generation Projection

Figure 19 illustrates the development of generating capacity by technology type over the projection period. Total installed capacity grows from 177 GW in 2006 to 212 GW in 2020. Fuel oil capacity drops from 20 to 14.6 GW. Existing nuclear units will be allowed to retire according to schedule with no new nuclear capacity assumed to come online during the study period in the WECC system. Major growth is projected for coal and renewables, with increases from 32 to 59 GW and 59 to 66 GW, respectively, with an additional 350 MW of small distributed generation capacity.

Figure 20 shows the technology mix of the new capacity additions. By 2020, a total of 50 GW of new capacity is projected to come on line. Coal takes the largest share with 27 GW (55% of total additions), followed by 14 GW of gas-fired units (29%), and 8 GW of renewables and small distributed generators (16%). We also assume that new coal plants will be equipped with a cooling system that will be much less vulnerable to drought conditions, such as dry cooling (which requires little or no water).

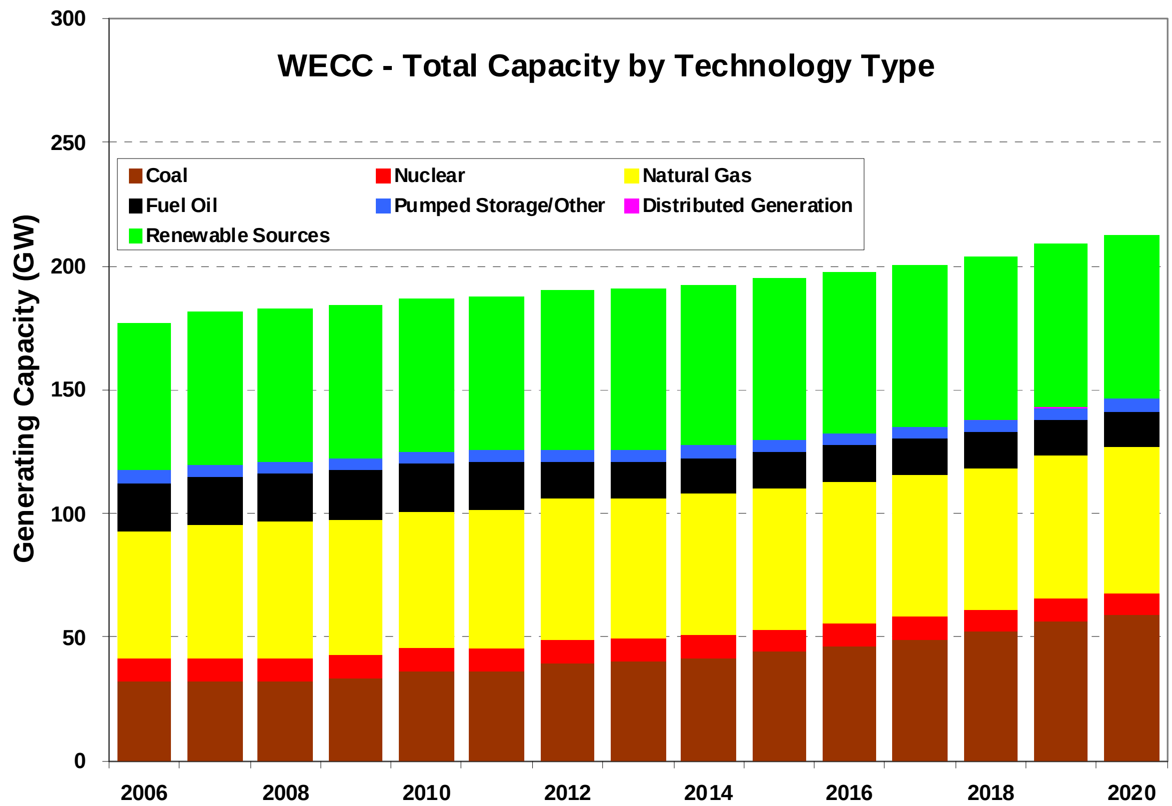

Figure 19: Baseline Projected Total Installed Capacity until 2020

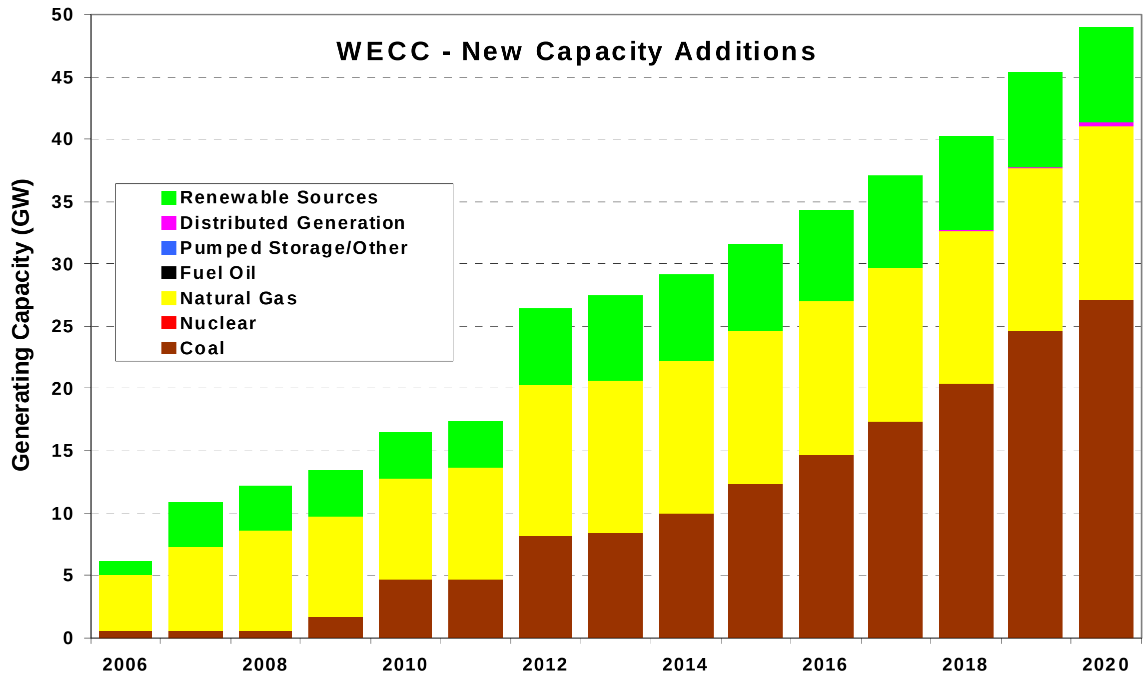

Figure 20: Baseline Projected Capacity Additions until 2020

Figure 21 provides a breakdown of renewable capacity for the WECC system until 2020. Conventional hydro capacity essentially stays flat at around 52 GW. Geothermal and wind increase from 2.4 to 3.1 GW and from 5.1 to 8.1 GW, respectively. Most of the renewable capacity additions come from hydropower (2 GW), wind (3 GW), and geothermal (0.7 GW), with the balance coming from smaller amounts of solar thermal and solar photovoltaic (PV), municipal solid waste, and wood/biomass.

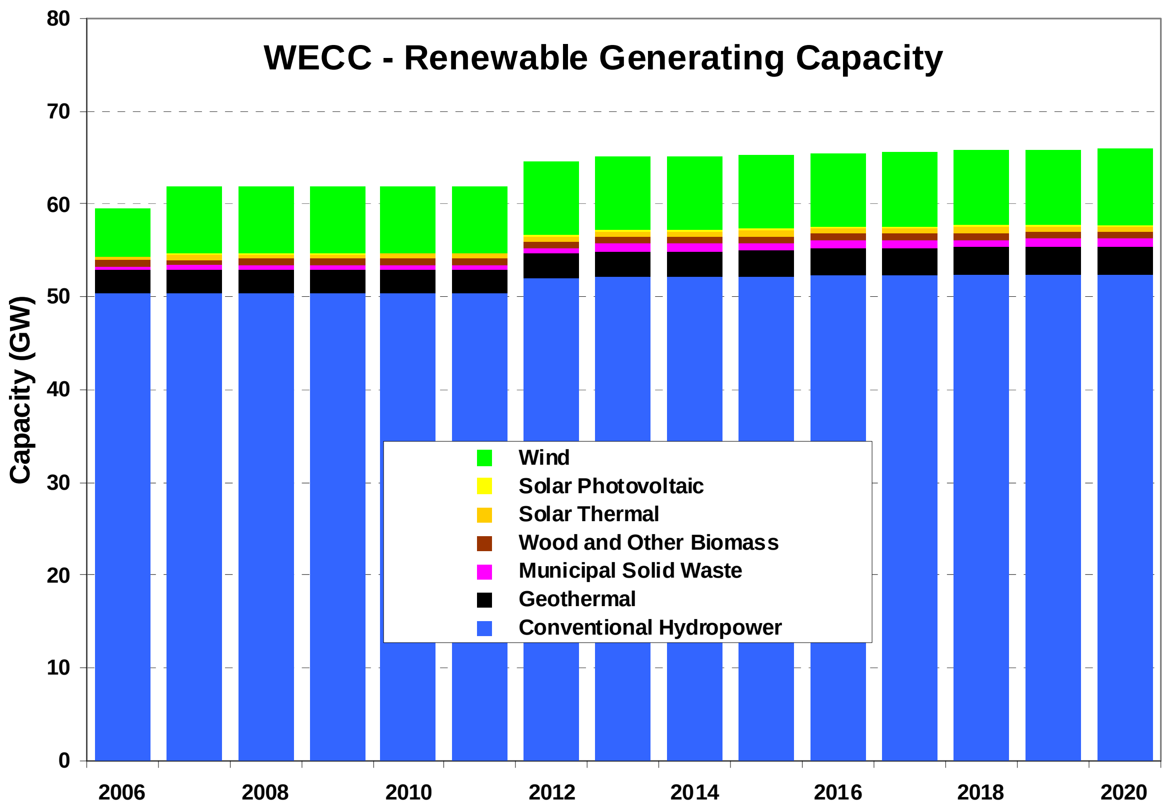

Figure 21: Baseline Projected Total Installed Renewable Capacity until 2020

3.2.3 CO_2 Emissions Projection

Carbon dioxide emissions result from the combustion of fuels containing carbon. In this study, the carbon-based fuels are coal, natural gas, fuel oil, and biomass. Because CO_2 emissions from biomass are highly dependent upon its composition, and because biomass makes up only about 1% of the generating capacity in the western United States, emissions from biomass power plants are not addressed in this study.

For the remaining thermal plants, CO_2 emissions vary by plant and depend on the fuel type, the efficiency of the power plant (or heat rate [measured in Btu/kWh]), and the amount of electricity the plant produces.

Emissions of CO_2 are calculated by using an emission factor. Emission factors have been developed for all types of carbon-based fuels; they measure the amount of CO_2 released (in lb) per unit of heat (Btu) generated during combustion. Emission factors for this study were obtained from the EIA Web site and are listed in Table 3. The value for coal is the average of the emission factor for bituminous and sub-bituminous coals, which are the two types of coal used in power plants in the western United States.

Table 3: CO_2 Emission Factor by Fuel Type

Fuel Type	CO_2 Emission Factor (lb/million Btu)
Coal	209.0
Natural Gas	116.4
Heavy Fuel Oil	173.7
Light Fuel Oil	161.3
Source: EIA undated[b].	

One of the results of the baseline thermal dispatch model run is the amount of electricity each plant in the unit inventory produces each month of the year. The unit database contains the efficiency or heat rate of each plant. Multiplying each plant's emission factor by the heat rate and the amount of electricity it generates in a year yields the amount of CO_2 the plant produces. Summing the CO_2 emissions from all the plants in the inventory yields the total amount of CO_2 produced by the electric power system. Table 4 lists the CO_2 emissions produced in each year of the study period.

Table 4: Amount of CO_2 Emissions for Baseline Scenario

Year	CO_2 Emissions (million short tons)
2010	408.4
2015	480.5
2020	548.1

3.3 Drought Scenario

This section discusses the major assumptions behind the drought scenario and compares the results of the thermal dispatch model runs for the baseline and drought scenarios with respect to generation mix, electricity prices, and CO_2 emissions.

3.3.1 Major Scenario Assumptions

A drought would adversely impact not only thermal power plants that use fresh surface water for cooling, but also hydroelectric power plants. Hydropower production affects the load that must be served by the thermal systems, including power plants that do *not* rely on surface water. As hydropower generation is reduced as a result of drought conditions, the thermal system must operate at a higher level to compensate for lower hydropower production levels. The WECC electric grid relies very heavily on hydroelectric power. Approximately 28% of the electric power capacity is supplied by hydroelectric power plants; this percentage increases to as much as 40% in a wet hydrologic year. Therefore, to accurately simulate the effects of drought on power system operations in the WECC, we must determine the impacts of a drought on hydroelectric power generation.

In order to determine how much the amount of electricity generated by hydroelectric power plants would be reduced as the result of a severe drought, we reviewed data on hydroelectric output from 1980 and 2005. We selected 1980 as the first year of the review period because the vast majority of current WECC hydropower capacity was on line in that year, and only a very small amount of that capacity had been retired during that time period. After reviewing this hydroelectric power generation data, we selected the year with the lowest hydroelectric power production to be representative of a year in which hydropower was most affected by severe drought conditions. We assumed that the monthly amount of generation and the capacity pattern for this historic low-hydropower year would represent the operation of hydroelectric power plants in each analysis year of the drought scenario.

After determining the hydroelectric generation pattern for the drought scenario, we calculate the load pattern to be supplied by the dispatchable thermal power plants using the method described in Section 2.4 (i.e., the nondispatchable or run-of-river hydroelectric generation value is subtracted from the hourly loads remaining after wind generation is subtracted from the original WECC loads). The peak shaving algorithm is then used to model the hourly generation pattern from dispatchable hydroelectric power plants and, ultimately, to calculate the hourly loads to be supplied by thermal power plants.

The inventory of thermal power plants in the WECC system that may be adversely impacted by a drought is based on a task performed by another Argonne team and described in a separate report (Kimmell and Veil 2009). Kimmel and Veil developed a database identifying fossil and nuclear power plants equipped with cooling systems that use fresh surface water. Data included plant name, location, plant code, owner, fuel type, nameplate capacity, source of cooling water, depth of cooling water intakes, and other characteristics.

As stated in that report, drought conditions can be highly variable across the United States; they can affect large areas of the country for a long period or small areas for a short period. Because of this variability, it is highly unlikely that all of the thermal power plants using surface water for cooling would have to shut down or curtail operations in an area as large as the western United States during a drought, regardless of the depth of their water intakes. Therefore, simultaneous shutdown of all power plants in the WECC system as the result of a drought would probably be an unrealistic scenario.

Consequently, we employ an alternative approach, using the information available on the U.S. Drought Monitor (University of Nebraska Lincoln 2009), a Web site funded by several Federal agencies and operated by the University of Nebraska Lincoln. Researchers compile and archive drought conditions on a weekly basis, from 2000 to the present, and post them on the Web site. Drought conditions are shown graphically by state and also by county within each state.

For this study, we chose drought conditions for the week of January 27, 2009, to develop a plausible drought scenario and to illustrate Argonne's electric power system simulation methodology. Figure 22 shows how data are displayed on the Web site on a regional and state basis.

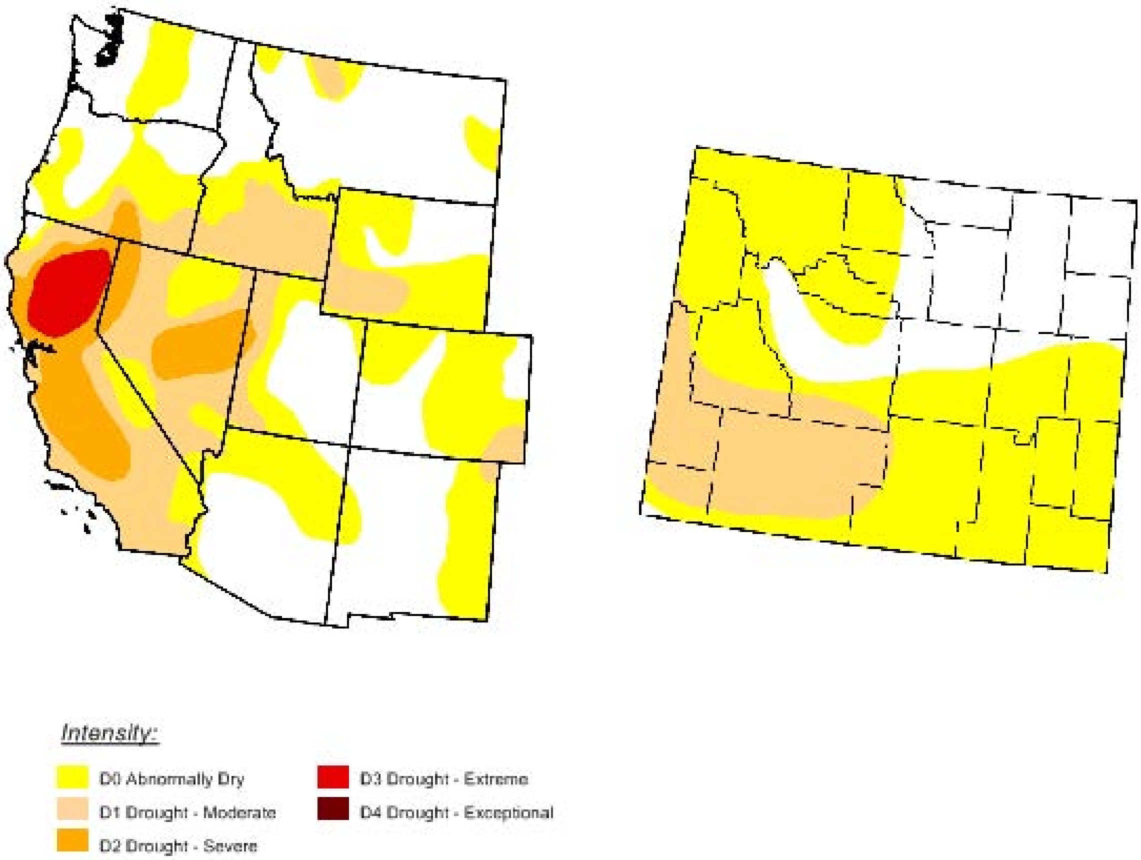

Figure 22: Sample of Data Displayed on the U.S. Drought Monitor Web Site — Western United States and Wyoming Drought Conditions as of January 27, 2009 (University of Nebraska Lincoln 2009)

To identify the plants that could be affected by the drought conditions during the chosen week, we compare the locations of the power plants in the WECC system with the maps on the U.S. Drought Monitor (University of Nebraska Lincoln 2009). We obtain the locations, in latitude and longitude coordinates, for each plant from the database of power plants developed by the companion Argonne study (Kimmell and Veil 2009). A geographical information system (GIS) program is used to plot the locations of the WECC power plants in the database; each location is visually compared with the state maps in the U.S. Drought Monitor. If a power plant was located in a part of the state that was designated as undergoing a moderate or more severe drought, it was chosen for shutdown or curtailment in each year of the study period.

By using this methodology, we identified a total of five plant sites in four states that would be shut down or for which operations would be curtailed. The total capacity of these plants is 3,284 MW; 2,820 MW (or 86%) of this total is supplied by coal-fired power plants. Because combined-cycle plants are very prevalent in the WECC system, their operation was handled in a special manner in this analysis. Combined-cycle plants consist of a gas turbine and a steam turbine that can be operated independently of one another, depending upon the configuration; typically, the gas turbine can operate independently of the steam turbine. The steam turbine is the only component that requires water for cooling. Therefore, in cases in which combined cycle plants were identified as possible candidates for shutdown during a drought, only the steam turbine portion of a combined-cycle unit was shut down.

3.3.2 Impacts on Generation Mix and Generation Cost

By using the technique described in Section 3.3.1, we determined the amount and generating pattern of hydroelectric power plants during a drought. Our analysis revealed that, in a severe drought year, the electrical generation from hydroelectric can drop by almost 30%. These data were input into the thermal dispatch model, and simulations were run for the two scenarios for 2010, 2015, and 2020. Table 5 and Figure 23 show model results for the amounts of electricity produced by fuel type. The amount of energy not served (ENS) is also shown. Energy not served is the amount of energy demanded by customers that the system's energy sources are unable to provide. This energy must be supplied by a source outside of the system or system operators must take steps to reduce load.

Table 5: Quantity of Electricity Generated by Fuel Type — Base and Drought Scenarios

	Base Scenario Energy (TWh)			Drought Scenario Energy (TWh)		
Fuel	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**
Nuclear	74.7	74.7	74.7	74.7	74.7	74.7
Coal	257.1	314.2	417.5	236.5	293.6	401.9
Natural Gas	244.9	252.1	161.1	320.1	326.1	231.0
Fuel Oil/Other	0.90	0.90	0.78	0.91	0.93	0.86
Renewable	36.8	44.4	47.1	36.8	44.4	47.1
Hydro	186.4	185.2	185.8	131.6	131.6	131.3
ENS	0.036	0.124	0.030	0.161	0.259	0.065
Total	800.8	871.6	886.9	800.8	871.6	886.9

In the drought scenario, electricity generated from coal dropped by 20.6 TWh (about 8% compared with the baseline) in 2010, by 20.6 TWh (6.6%) in 2015, and by 15.6 TWh (3.7%) in 2020. The 30% drop in generation from hydroelectric power during a drought resulted in about 54 TWh less hydroelectric energy generated in the drought scenario. A significant increase in generation from plants using natural gas compensated for the shortfall in generation from coal and hydropower. Electricity production from natural gas rose by 75.3 TWh (30.8% compared with the baseline) in 2010, 74 TWh (29.3%) in 2015, and 70 TWh (43.5%) in 2020. Generation from other fuel sources, such as fuel oil and renewables, rose only slightly — no more than 0.1 TWh in any simulated year. Natural gas plants made up for almost the entire amount of electricity not generated by coal and hydropower.

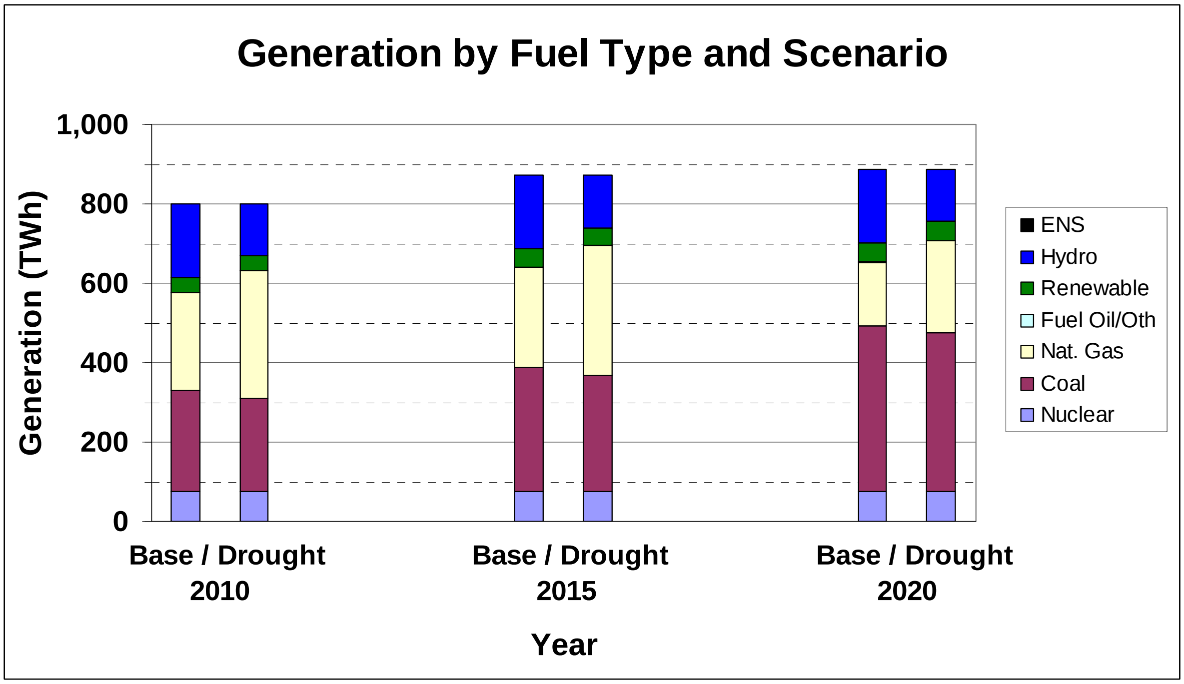

Figure 23: Electricity Generated by Fuel Type — Base and Drought Scenarios (Note: The quantity of ENS and Fuel Oil/Other cannot be seen on this plot because of its small amount compared with the amount from other sources.)

The reason that natural gas plants were able to generate most of the electricity lost as a result of coal plant shutdown and the reduction in hydropower can be seen by examining their capacity factors from the base scenario model runs. The capacity factors of natural gas plants in 2010, 2015, and 2020 were 37.4%, 36.7%, and 23.1%, respectively. Because their capacity was not fully utilized, they were able to pick up the slack in the drought scenario. By 2020 though, coal's contribution starts rising, while the contribution of natural gas begins to fall. This is because coal plants with cooling technologies less vulnerable to drought are being installed in greater numbers and, by 2020, begin to displace generation from natural gas plants which, in 2010 and 2015, picked up the slack for generation from coal plants lost to drought conditions.

Nuclear power plants were unable to supply additional generation capacity in the drought scenario for two reasons: (1) no new nuclear plant came online during the study period, and (2) nuclear provides base load electricity and already generates up to its maximum potential even in the base case. There was no excess nuclear capacity to generate more electricity. In the WECC system, it is also fortunate that cooling water for nuclear power plants comes predominately from sources other than fresh surface water; otherwise, they may have been subject to the drought shutdown.

The amount of ENS increased significantly in the drought scenario, rising by more than 3.5 times in 2010 and more than doubling in 2015 and 2020. Furthermore, if ENS occurs, there is more than a 99.9% chance that it would occur in either July or August because demand for electricity in the WECC peaks during the summer months.

Because of the sharp increase in electricity produced by natural gas plants in the drought scenario, the cost to produce electricity compared with the cost in the baseline scenario increased sharply as well. This is because operating costs of natural gas plants can be more than 3 times that of coal plants. Total electricity production costs in the baseline scenario were $17.9 billion in 2010, $17.8 billion in 2015, and $15.2 billion in 2020. Total ENS costs in the baseline scenario were $33.9 million in 2010, $124 million in 2015, and $30.9 million in 2020. Figure 24 shows the differences in production costs and ENS costs between both scenarios. Production costs rose by $4.5 billion (25.2%) in 2010, $3.9 billion (21.9%) in 2015, and $3.5 billion (22.9%) in 2020. Costs of ENS rose by $126 million in 2010, $135 million in 2015, and $33.4 million in 2020, assuming that ENS is valued at about $1000/MWh. This is considered a conservative value; surveys have indicated that the cost of ENS can frequently exceed $2,000/MWh (Cramton and Lien 2000).

Production costs and ENS costs decrease over time because new coal plants with cooling technologies less vulnerable to drought begin displacing generation from natural gas plants, whose generation increased in 2010 and 2015 to make up for generation lost from existing coal plants as a result of drought conditions. The new coal plants are more efficient and much less expensive to operate.

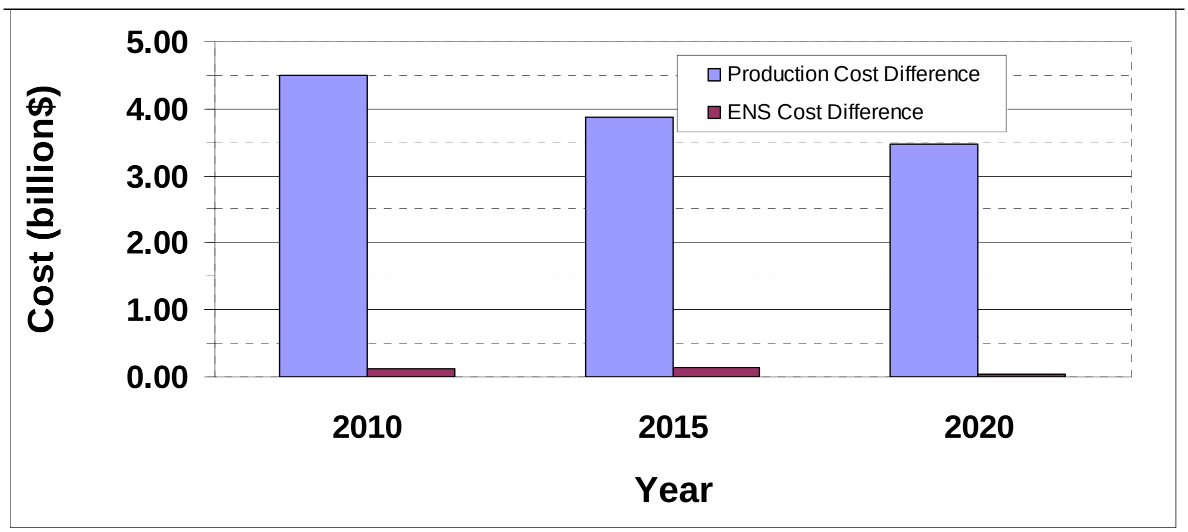

Figure 24: Production Cost and ENS Cost Differences between Base and Drought Scenarios

3.3.3 Impacts on Electricity Prices

The thermal dispatch model generates a variety of price outputs, including monthly price distributions and hourly chronological prices with associated uncertainty ranges for user-specified percentiles. Table 6 lists average monthly system-wide electricity prices, calculated on the basis of monthly price distributions obtained from the model.

Table 6: Average Monthly Price of Electricity — Base and Drought Scenarios

Month	Average Price of Electricity ($/MWh)						Price Difference (%)		
	Base Scenario			Drought Scenario					
	2010	2015	2020	2010	2015	2020	2010	2015	2020
Jan	61.01	54.04	51.76	65.97	58.32	56.79	8.1	7.9	9.7
Feb	60.21	53.30	50.67	67.21	59.40	54.29	11.6	11.5	7.2
Mar	55.58	49.14	46.02	60.84	53.38	50.69	9.5	8.6	10.1
Apr	54.95	48.47	43.61	61.08	53.45	50.27	11.1	10.3	15.3
May	54.69	46.88	40.57	62.23	53.06	48.29	13.8	13.2	19.0
Jun	55.35	48.71	40.04	61.80	54.96	47.48	11.7	12.8	18.6
Jul	69.14	68.07	54.17	91.67	89.16	67.24	32.6	31.0	24.1
Aug	78.48	87.87	61.75	105.70	109.75	71.27	34.7	24.9	15.4
Sep	59.97	52.85	44.95	64.05	56.73	50.17	6.8	7.3	11.6
Oct	63.20	55.75	43.04	65.47	57.86	47.24	3.6	3.8	9.8
Nov	62.97	55.36	52.13	65.89	58.18	56.36	4.6	5.1	8.1
Dec	59.44	52.70	50.89	66.72	58.71	55.30	12.2	11.4	8.7

The difference in the average price between the two scenarios is highest in the summer months (July and August), when demand in the WECC regions peaks. In 2010 and 2015, the average price for the drought scenario was 25–35% higher in those months. The difference in average prices drops considerably with time. In 2010, the average drought price in August was 35% higher than the base scenario price, but by 2020, the price was only 15% higher.

The distribution of prices is shown in Figures 25, 26, and 27 for January, a typical winter month, and August, the peak summer month. The price distribution is much larger for August compared with January for all years. In fact 5–10% of the time, prices exceed $150/MWh in August 2010 and 2015 in the drought scenario. That probability drops to about 2% in August 2020. Also, as the study progresses, the price distribution for both scenarios shifts toward lower prices.

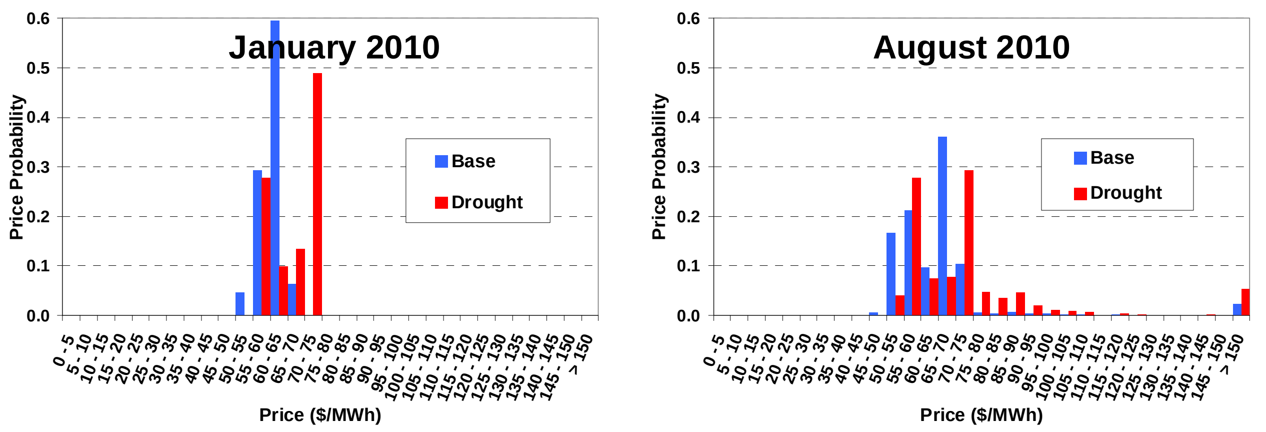

Figure 25: Price Distribution for January and August 2010

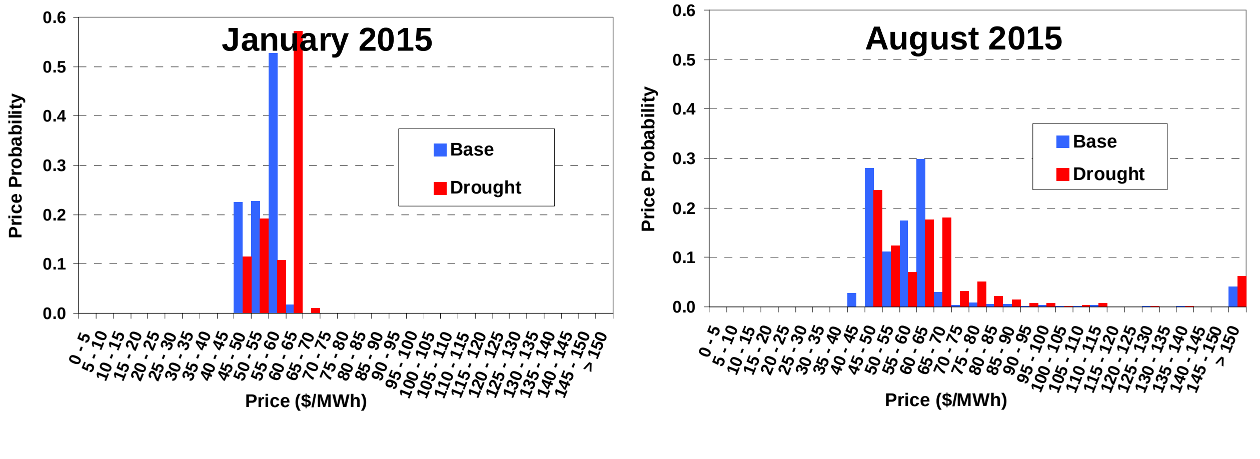

Figure 26: Price Distribution for January and August 2015

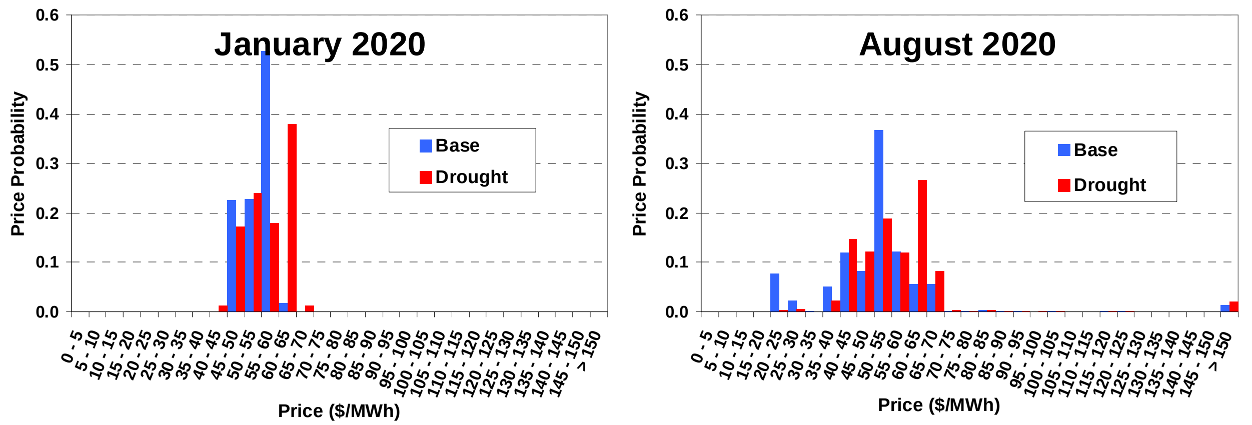

Figure 27: Price Distribution for January and August 2020

3.3.4 Impacts on CO_2 Emissions

Emissions of CO_2 were calculated for each scenario. The results are listed in Table 7. In the drought scenario, CO_2 emissions were higher by about 20 million tons in each year simulated. On a percentage basis, the increase was rather small; emissions were 5.4% higher in 2010 and fell to 4.3% higher in 2015, and 3.8% higher in 2020.

Table 7: Comparison of CO_2 Emissions — Base and Drought Scenarios

Year	Base Scenario (10^6 tons of CO_2)	Drought Scenario (10^6 tons of CO_2)	Difference (10^6 tons of CO_2)
2010	408.4	430.5	22.1
2015	480.5	501.3	20.8
2020	548.1	569.1	21.0

Because natural gas-fired power plants generate the vast majority of electricity to replace the capacity lost by the shutdown of coal plants and the reduction in generation by hydropower plants in the drought scenario, the increase in CO_2 emissions may not be as high as expected. This could be because (1) natural gas generates less CO_2 per Btu than coal, and (2) the natural gas plants that would have produced the electricity for the shut-down coal plants are slightly more efficient than coal plants (i.e., they have a lower heat rate or use less fuel to produce a unit of electricity).

4 SUMMARY AND CONCLUSIONS

This study resulted in a number of important observations regarding the operation of the electric power system in the western United States and how system operation changes caused by severe drought conditions, particularly in the near term (i.e., less than 10 years in the future). This is the time period when utilities would have difficulty bringing a sufficient amount of new capacity online in response to persistent drought conditions, other than those plants already in the construction pipeline. These observations can also be applied to electric power systems in other parts of the United States to provide some insights into how they might be affected during a drought.

4.1 Effect of Drought on Generation Mix

One observation is that natural gas plants replaced virtually all of the generation lost as a result of plant shutdowns. In the WECC regions, more than 94% of plants that draw fresh surface water for cooling use coal for fuel, while fewer than 6% of those plants use natural gas. Natural gas plants were in the best position to make up for the lost generation because they are operated at much lower capacity factors than coal plants. The average capacity factor of natural gas plants in the WECC regions is less than 40%, while the average capacity factor of coal plants exceeded 80%. Therefore, the natural gas plants have excess capability to produce more electricity.

Our study showed that other sources, such as nuclear and renewables, are unable to provide more electricity for various reasons. Nuclear power plant growth is constrained, and they are already operating at their maximum capacity factors. Renewables, such as wind, geothermal, and hydroelectric, are already maximizing their energy capacity.

This observation could be applied to power systems in other parts of the United States. Coal-fired power plants are very prevalent in all U.S. power systems, and they typically operate at very high capacity factors because of their low operating cost. They also use large quantities of water, much of which is supplied from fresh surface water sources. Therefore, a heavy reliance on natural gas plants is likely in the near term to replace power lost to plant shutdowns as a result of drought. Natural gas plants operate at moderate capacity factors, between 25% and 50%, and therefore have the capability to produce more electricity quickly.

Electric power systems in the United States that do not have sufficient natural gas plant capacity to replace electricity lost by plant shutdowns that result from drought would have a difficult time generating the needed energy, particularly in the near term. For example, in North Carolina, only 2.5% of electricity generation comes from natural gas, while 60% comes from coal, 32% from nuclear, and 3.5% from hydro (Vinluan 2007). With this type of generation mix, providers may have a difficult time meeting their customers' electricity needs during a drought; they may have to purchase power on the open market at prices that are likely driven up by drought conditions.

However, this study shows that systems that rely heavily on coal plants would realize significant benefits in the long term by building new coal plants equipped with advanced cooling technologies to reduce their vulnerability to drought conditions.

4.2 Effect of Drought on Energy Prices and Water Supplies

Electricity costs in the drought scenario are very high compared with costs in the base scenario in the first 5 to 10 years, but the cost difference grows smaller with time. This is because new coal plants come online steadily and begin generating more of the electricity lost from plant shutdowns that result from drought. The new coal plants use advanced cooling technologies, such as dry cooling, that are much less vulnerable to drought conditions. Coal plants can be three times less expensive to operate as natural gas plants.

With natural gas plants picking up the slack for other plants shut down during a drought, use of natural gas by power generators will increase, which will likely raise the price of natural gas in the market. Because natural gas is used domestically for cooking and heating, consumers may see not only their electric rates increase, but also their domestic natural gas rates.

This has already been happening in the last several years; power generators have been constructing natural gas electric plants because they can be constructed more cheaply than large coal plants and can come online faster because they are smaller and face less opposition by the local population. However, quantification of natural gas price impacts is outside the scope of this study.

Some utilities have already recognized the drought problem and have taken action to diversify their water supplies. In 2004, the owners of the Laramie River Station in Wyoming negotiated rights to purchase groundwater from local landowners and installed a 90,000-foot-long pipeline to deliver groundwater to supplement cooling water from the Grayrocks Reservoir. Pipeline operation began in October 2004 (Heartland Consumer Power District 2005).

Produced water from a coal bed natural gas project in the Powder River Basin has been proposed as a source of cooling water for both the Laramie River and Dave Johnston power stations (All Consulting 2006). Also, in 2004, the Nebraska Public Power District spent $12 million and installed 40 wells at its 1,300-MW, coal-fired Gerald Gentleman Station to ensure there will be enough water in the event that Lake McConaughy goes dry (Laukaitis 2004).

Diversification of water supplies, particularly for large steam turbine power plants such as coal and nuclear plants, will have to be seriously considered in other parts of the United States. Droughts have already presented a problem in the southeastern United States (in 2007); such problems are likely to continue in the Southeast and may affect other regions in the future. However, groundwater use may not be a viable solution in all cases because groundwater is often used for other, more important purposes, such as for drinking water.

4.3 Effect of Drought on CO_2 Emissions

Increases in CO_2 emissions from changes in electric power system operations that occur due to a drought appear to be minor. In this case study, CO_2 emissions increased just over 5% in the drought scenario compared with the base scenario. Although natural gas plants increased their generation dramatically, the higher efficiency of these plants, coupled with a CO_2 emission factor for natural gas that is almost half that of coal, meant only slightly increased CO_2 emissions. Similar results would be expected for other U.S. electric power systems if their proportion of coal to natural gas generation is similar to that in the West.

4.4 Effect of Drought on Use of Nuclear Power

Drought could have a serious effect on nuclear power plants, in addition to coal plants. In this case study, the cooling systems of the nuclear power plants located in the WECC regions predominately used cooling sources other than fresh surface water, such as ocean water and sewage effluent. Plants with these cooling sources are much less likely to be shut down or have capacity curtailments during a severe drought. However, other parts of the United States rely more heavily on nuclear power plants that receive cooling water from fresh surface water sources.

As recently as summer 2007, the southeast region of the United States faced a very severe drought, prompting North Carolina to develop contingency plans to manage power plant output in response to falling water levels (Vinluan 2007). Power systems in the United States that rely heavily on coal and nuclear power should be studied more carefully to evaluate their vulnerability to drought and to determine whether mitigation strategies are needed.

4.5 Areas for Future Study

This study did not account for transmission constraints, which may curtail delivery of electric power from the generating station to the load. We assumed that any generator in the system could send electricity to any load. In effect, the spatial component of loads and generators was not taken into account. Under normal operating circumstances, this is a reasonable assumption; however, in some circumstances, this may oversimplify the problem and not yield reliable results. Studying the effects of a drought may be one of those circumstances because droughts can affect a very specific area without affecting other areas.

In reality, the transmission system can impose severe constraints on transferring power from one area to another. Transmission lines in some areas may be insufficient to handle normal loads, let alone heavy loads. Also, some transmission lines may be sufficient under normal operating conditions, but could easily become overloaded under extreme circumstances. Environmental conditions, such as excessive heat which often accompanies a drought, can also limit the electric capacity of transmission lines.

Many areas of the United States have transmission corridors in which the lines are very close to their operating limit; severe circumstances can easily overload those lines. This study could be enhanced to (1) account for constraints in transmission capacity and (2) evaluate how that may affect power plant operations during drought conditions. The WECC system includes several transmission corridors in which transmission lines have serious power transfer constraints, particularly lines that serve high-population centers like Los Angeles. There are transmission bottlenecks in many other parts of the United States as well because system loads and the generating capacity serving those loads can be concentrated in areas far apart.

This study focused on plant shutdowns or curtailments due to low water intake levels caused by droughts. However, droughts often occur with very hot conditions, which may result in other effects not taken into account in this study. Power plants have limits on the temperature of water they return to the cooling source. Most plants cannot discharge water warmer than 90° to 110°F. If the water temperature is too high, the plant must curtail the power level so that the water delivered back to the source is below the threshold value. This condition often occurs in July and August — the months of peak load, not only in the WECC regions, but also in most of the United States. Plants that are not affected by low water levels may be affected by temperature limits for cooling water discharge. This condition could curtail more capacity in an electric power system already affected by drought and further exacerbate the problem. This study could be enhanced to take this effect into account.

Also, plants that may not use any cooling water could be affected by excessive heat, because if intake air is too hot, plant power output is reduced. This problem, which can occur in gas turbines in hot summer months, is often remedied by humidifying the inlet air. This study could be enhanced to evaluate the extent of this issue and determine whether it may substantially affect model results.

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