Appendix D: Wholesale Electricity Price Forecast

INTRODUCTION

The Council prepares and periodically updates a 20-year forecast of wholesale electric power prices. This forecast is used to establish benchmark capacity and energy costs for conservation and generating resource assessments for the Council's power plan. The forecast establishes the base electricity market price for the Council's Resource Portfolio Model and is used in the ProCost model by the Regional Technical Forum to assess the cost-effectiveness of conservation measures. The Council's price forecast is also used by other organizations for assessing resource cost-effectiveness, developing resource plans and for other purposes.

The Council uses the AURORAxmp® Electric Market Model[1] to forecast wholesale power prices. AURORAxmp® provides the ability to incorporate assumptions regarding forecast load growth, future fuel prices, new resource costs, capacity reserve requirements, climate control regulation and renewable portfolio standard resource development into its forecasts of future wholesale power prices. The forecasting model can also be used for analysis of issues related to power system composition and operation, such as the effectiveness of greenhouse gas control policies.

Electricity prices are based on the variable cost of the most expensive generating plant or increment of load curtailment needed to meet load for each hour of the forecast period. The

[1] The AURORAxmp Electric Market Model, available from EPIS, Inc (http://www.epis.com).

forecast represents the price of a flat hourly energy delivered to a wholesale delivery points (i.e. inclusive of integration and transmission costs). Unless otherwise stated, the prices reported in this appendix are for the "PNW Eastside" load-resource area defined as Washington and Oregon east of the Cascades, Northern Idaho and Montana west of the Continental Divide. Prices in this area are considered to be representative of Mid-Columbia transactions. Other zonal series are available from the Council on request.

The Council's wholesale power price forecast has been used by others as a measure of avoided resource cost. The Council cautions that this price forecast may not be a suitable stand-alone measure of avoided resource costs. This issue is further discussed in the "Avoided Resource Cost" section of this appendix.

The annual and monthly Base case forecast values are provided in tables at the end of this Appendix. Hourly values for the Base case and values for the sensitivity cases are available from the Council on request. All prices are in constant 2006 year dollar values unless otherwise indicated.

SUMMARY OF KEY FINDINGS

Three factors are expected to significantly influence the future wholesale power market: the future price of natural gas; the future cost of carbon dioxide (CO_2) production; and renewable resource development associated with state renewable portfolio standards (RPS). These factors will affect the variable cost of the hourly marginal resource and hence the wholesale power price.

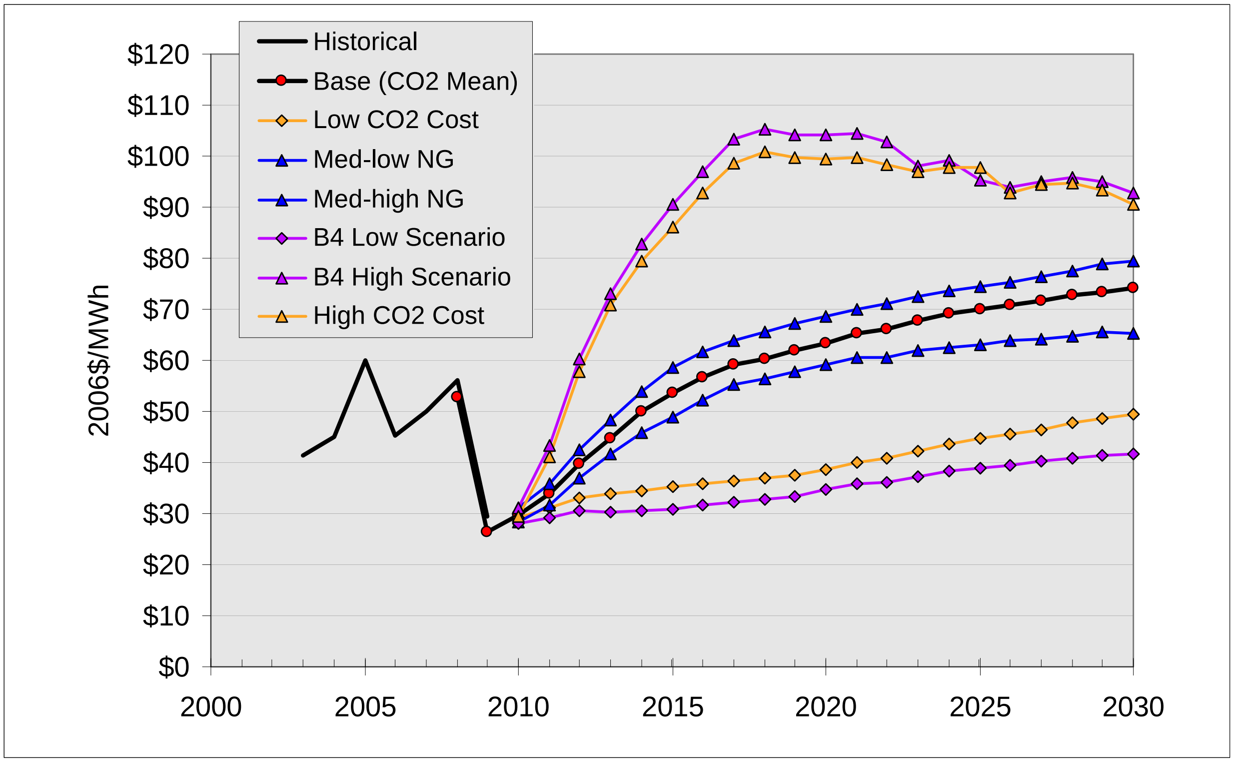
Because natural gas is a relatively expensive fuel, natural gas-fired plants are often the marginal generating unit, and therefore determine the wholesale price of electricity during most hours of the year. CO_2 allowance prices or taxes will raise the variable cost of coal-fired units more than that of gas-fired units because of the greater carbon content of coal. Lower CO_2 costs will raise the variable cost of both gas and coal units, but not enough to push coal above gas to the margin. High CO_2 costs will move coal to the margin, above gas. In either case, the variable cost of the marginal unit will increase. State RPS are expected to force the development of large amounts of wind, solar and other low-variable cost resources, in excess of the growth in demand. This will force lower variable cost fossil units to the margin, tending to reduce market prices.

A base case forecast, four sensitivity studies, and two bounding scenario cases were run. The base case assumes medium case fuel prices and mean CO_2 prices. All forecast cases assume 95 percent achievement of state renewable portfolio standards, average hydropower conditions, medium load growth and achievement of all cost-effective conservation. The changing case assumptions are as follows:

Case	Fuel Prices	CO_2 Cost
Base	Medium Case	Mean of RPM $0 -100 case
Low CO_2 Cost	Medium Case	90% prob. of exceedance decile
High CO_2 Cost	Medium Case	10% prob. of exceedance decile
Medium-Low Natural Gas	Medium-low NG	Mean of RPM $0 -100 case
Medium-High Natural Gas	Medium-high NG	Mean of RPM $0 -100 case
Low Scenario	Medium-low NG	90% prob. of exceedance decile
High Scenario	Medium-high NG	10% prob. of exceedance decile

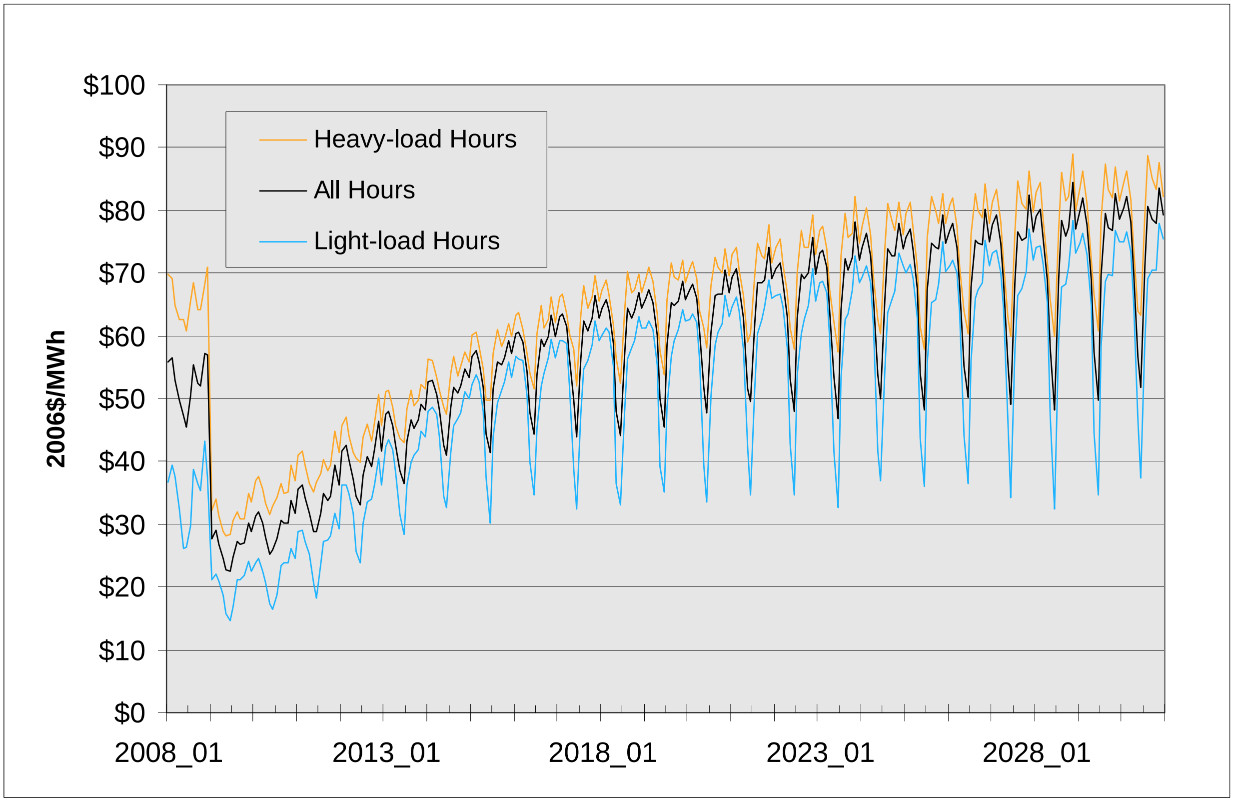
For the Base forecast, wholesale power prices at the Mid-Columbia trading hub are projected to increase from $30 per megawatt-hour in 2010 to $74 per megawatt-hour in 2030 (real 2006 dollar values). For comparison, Mid-Columbia wholesale power prices averaged $56 per megawatt-hour in 2008 (in real 2006 dollars), dropping abruptly to $29 in 2009 with collapse of natural gas prices and reduction of demand due to the economic downturn. The levelized present value of the 2010-29 Base case forecast is $56 per megawatt-hour. Figure D-1 illustrates recent historical prices and forecast wholesale power prices for the cases.

Figure D-1: Historical and Forecast Annual Average Mid-Columbia Wholesale Power Prices



Northwest electricity prices exhibit a seasonal pattern associated with spring runoff in the Columbia River Basin and lower loads as the weather moderates. The forecasts exhibit this pattern when viewed on a monthly average basis. Figure D-2 shows the monthly average heavy-load hours, all hours, and light-load hours prices for the Base forecast.

Figure D-2: Monthly Average Base Case Forecast of Mid-Columbia Wholesale Power Prices



APPROACH AND METHODOLOGY

The Council uses the AURORA$^{xmp®}$ Electricity Market Model[2] to forecast wholesale power prices. Hourly prices are based on the variable cost of the most expensive (in variable terms) generating plant or increment of load curtailment needed to meet load for each hour of the forecast period. AURORA$^{xmp®}$, as configured by the Council, simulates plant dispatch in each of 16 load-resource areas making up the Western Electricity Coordinating Council (WECC) electric reliability area (Figure D-3). Four of these areas comprise the four Northwest states: Eastern Oregon and Washington, northern Idaho and Western Montana (Pacific Northwest Eastside, Area 1); southern Idaho (Area 5), Eastern Montana (Area 6), and Western Oregon and Washington (Pacific Northwest Westside, Area 16).

These areas are defined by transmission constraints and are each characterized by a forecast load, existing generating units, scheduled project additions and retirements, fuel price forecasts, load curtailment alternatives and a portfolio of new resource options. Transmission interconnections between load-resource load-resource areas are characterized by transfer capacity, losses and wheeling costs. The demand within a load-resource area may be served by native generation, curtailment, or by imports from other load-resource areas if economic, and if transmission transfer capability is available.

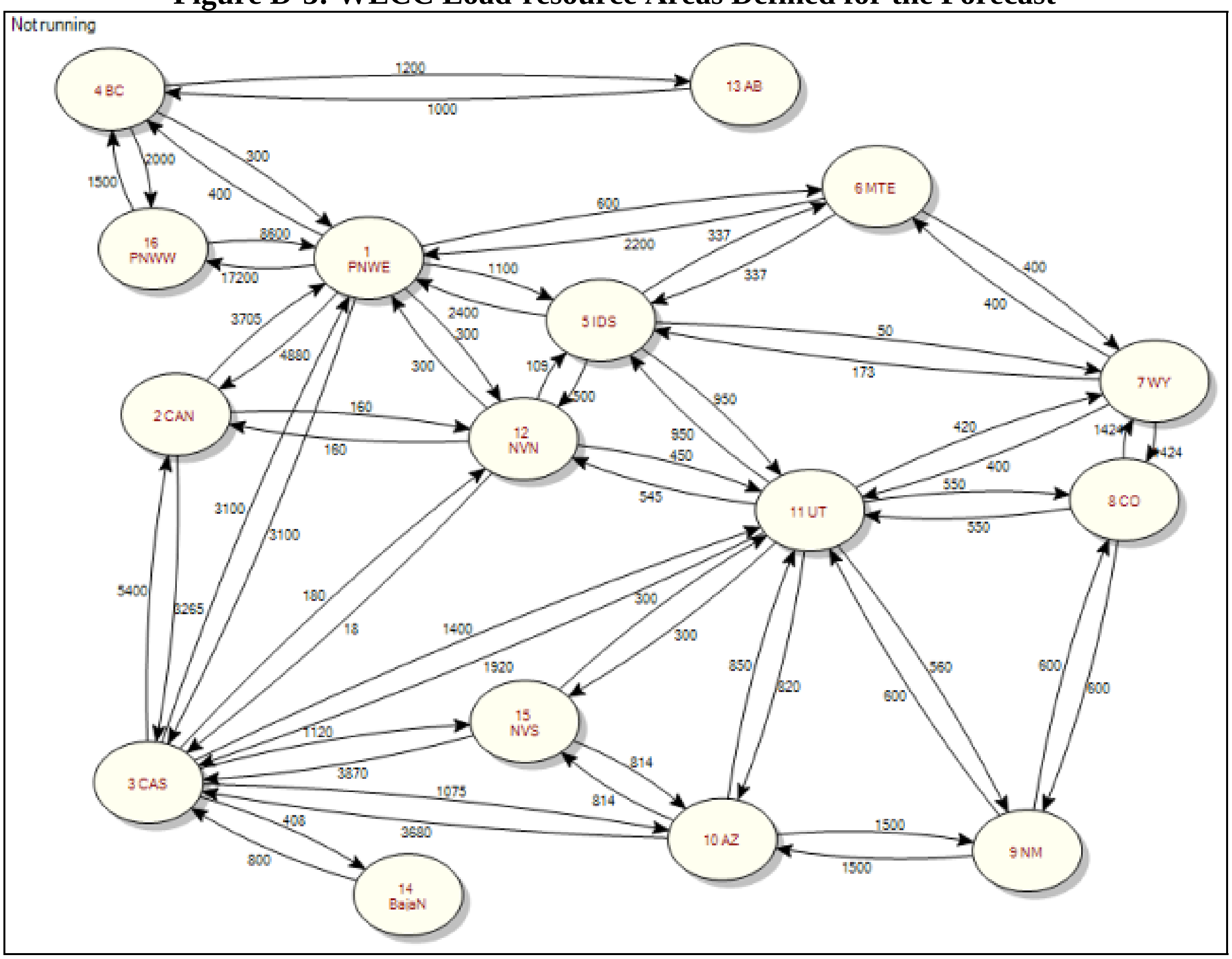
[2] Supplied by EPIS, Inc. (www.epis.com). AURORA^{xmp} Version 9.6.1011 was used for the final Sixth Power Plan forecasts described here.

A forecast is developed using the two-step process. First, a forecast of capacity additions and retirements economically supply energy to the system while maintaining firm capacity standard is developed using the AURORA$^{xmp®}$ ®long-term resource optimization logic. This is an iterative process, in which the net present value of possible resource additions and retirements are calculated for each year of the forecast period. Existing resources are retired if market prices are insufficient to meet the future fuel, operation and maintenance costs of the project. New resources are added if forecast market prices are sufficient to cover the fully allocated costs of resource development, operation, maintenance and fuel, including a return on the developer's investment and a dispatch premium.

The electricity price forecast is developed in the second step, in which the mix of resources developed in the first step is dispatched on an hourly basis to serve forecast loads. Every-hour dispatch more accurately models the interaction of system resources than the sampling process used for the capacity expansion step. Power plant ramping limits and the full representative hourly output of wind and other variable resources are incorporated in this step to more accurately portray system operation. The variable cost of the most expensive generating plant or increment of load curtailment needed to meet load for each hour of the forecast period establishes the forecast price for that hour.

The price forecast developed for Area 1 (Pacific Northwest Eastside) is considered representative of Mid-Columbia trading hub prices.

Figure D-3: WECC Load-resource Areas Defined for the Forecast



The final price forecast consists of a base case, corresponding to the mean or average values of variables such as demand growth, fuel prices, hydro conditions and forecast carbon dioxide allowance prices (or tax cost). Sensitivity cases were run to test the effect of higher or CO_2 costs and higher and lower natural gas prices. Finally, two bounding scenarios were run, representing concurrent low natural gas and CO_2 prices and high natural gas and CO_2 prices.

ASSUMPTIONS

Demand

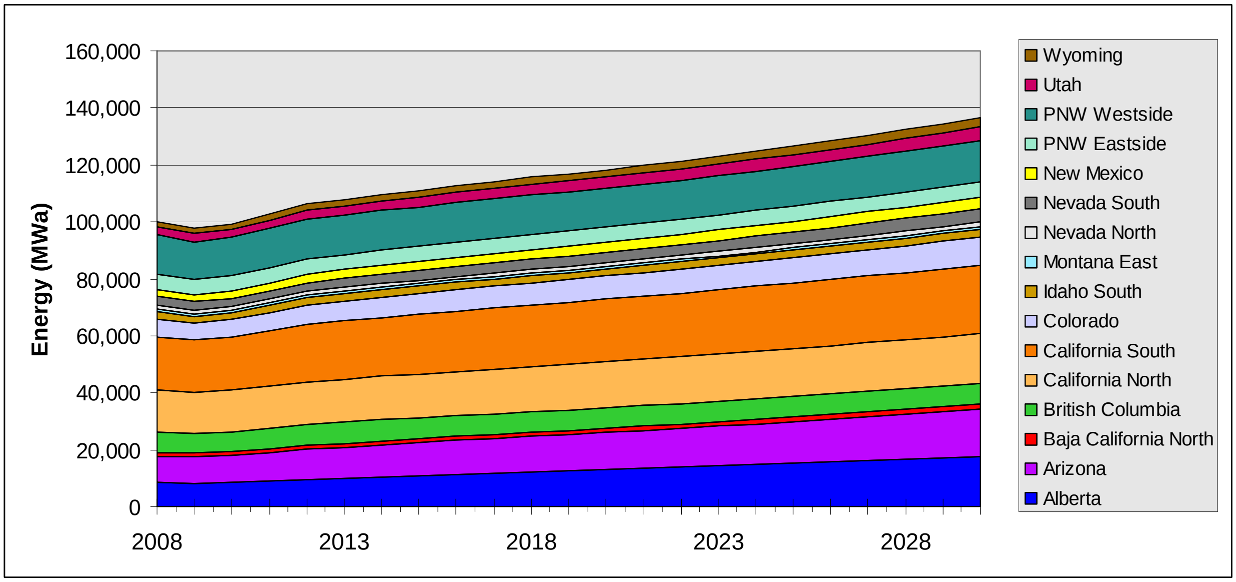
Energy and peak load forecasts for the four Northwest areas are provided by the Council's demand forecast model. Council staff projected both energy and peak demand growth for nine of the remaining 12 areas (those in the U.S.) based on 2008-2017 forecasts submitted to the FERC (EIA Form 714) by electric utilities. The forecast for Alberta for the same years was based on the forecast by the Alberta Electric System Operator (AESO).[3] The Council's forecast for British Columbia was based on a forecast BC Hydro submitted to the Western Electricity Coordinating Council (WECC) for the period 2010-2017, supplemented by data from the British Columbia Transmission Corporation (BCTC)[4] for 2007 and interpolation for 2008 and 2009. The forecast load for northern Baja California in Mexico was based on the forecast submitted to WECC for 2010-2017, the 2006 load previously used by AURORA, and interpolated values for 2007-2009.

AURORA^{xmp} requires load projections for each year to 2053. For most load-resource areas, Council staff extended the forecasts past 2017 by calculating a 5-year rolling average for the previous five years. Arizona and New Mexico loads were projected to grow from 2021 through 2027 at the same rate as the projected population growth in each state. After 2027, load was projected to continue to grow at the 2027 rate. The load for northern Baja California was similarly projected, except that the population growth rate for New Mexico was used for 2021-2027 (population projections for Baja California were unavailable).

The forecasted energy loads of the 16 load-resource areas are illustrated in Figure D-3. Tabular data is provided in Table D-1.

[3] http://www.aeso.ca/downloads/Future_Demand_and_Energy_Outlook_(FC2007_-_December_2007).pdf
[4] http://www.bctc.com/NR/rdonlyres/C6E06392-7235-4F39-ADCD-D58A70D493C7/0/2006controlareaload.xls

Figure D-4: Forecasted Energy Loads for the Load-resource Areas



Firm Capacity Standards

The firm capacity standard represents a requirement that a region's generating resources provide enough firm capacity to meet the region's peak demand plus a specified margin for reliability considerations. The model uses two input parameters to simulate achievement of a region's firm capacity standard. The first is a planning reserve margin target for each region. The second is a firm capacity credit for each type of generating resource.

Planning Reserve Margin Targets

Reserve margin targets can be specified for each load-resource area, for an aggregation of load-resource areas called an operating pool, or for both. The Council has specified planning reserve margin targets for two operating pools: (1) the Pacific Northwest region, except Southern Idaho, and (2) the California Independent System Operator (CAISO). The remaining load-resource areas are given individual reserve margin targets. Southern Idaho was not modeled within the Northwest pool because of existing transfer constraints between southern Idaho and the rest of the region.

For the CAISO and the stand-alone areas other than Southern Idaho, the planning reserve margin target was set at 15 percent. For the Pacific Northwest, including Southern Idaho, the Council configured AURORA^{xmp} to reflect the capacity standard of the Pacific Northwest Resource Adequacy Forum. The adequacy forum has determined that reserve margin targets of 25 percent in winter and 19 percent in summer correspond to an overall system loss-of-load probability of 5 percent.

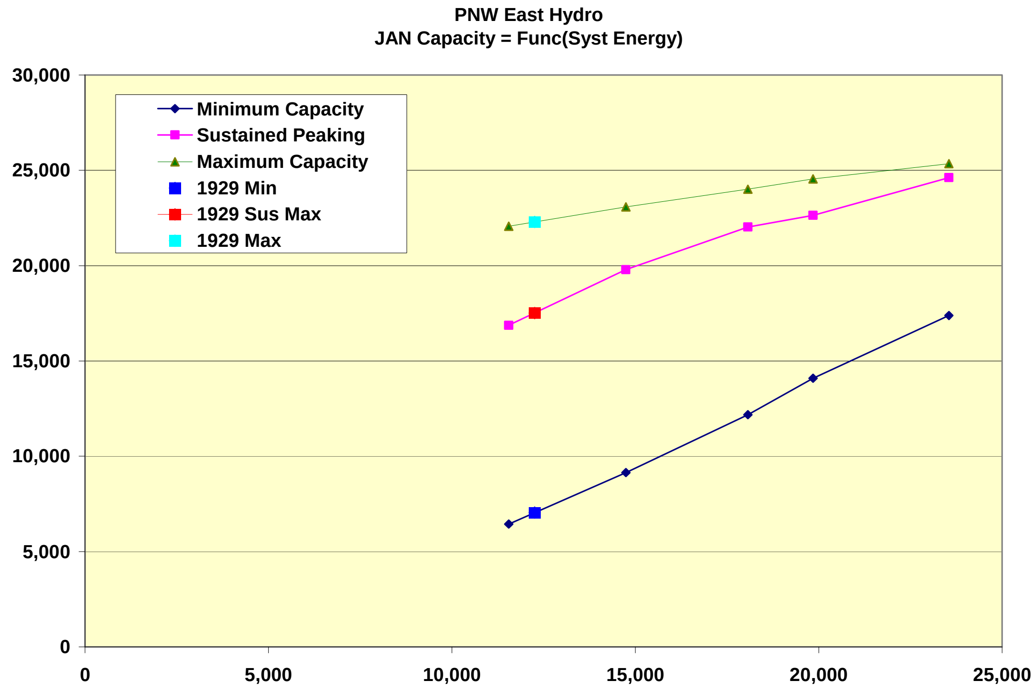
The Adequacy Forum targets reflect a specific set of resource and load assumptions that cannot be easily replicated in AURORA^{xmp}. For example, the winter reserve margin target is based on consideration of the highest average demand for a three-day 18-hour sustained peak period, while AURORA^{xmp} is limited to consideration of the single highest hour of demand. Moreover, multi-seasonal reserve margin targets cannot be input directly into AURORA^{xmp}. For electricity price forecasting purposes, the Council converted the Adequacy Forum's multiple-hour capacity reserve margin targets to an equivalent single-hour target. Adjustments were also made to reflect consistent treatment of spot market imports, hydro conditions and flexibility, and independent power producer generation. The equivalent single-hour winter capacity reserve margin for the Northwest is 18 percent. Conversion of the adequacy forum's capacity reserve margin targets does not reflect a change in the adequacy standard, but rather an adjustment to approximate the complex Northwest standards using the simpler reserve parameters available in AURORA^{xmp}. Both the forum's target and the target used in AURORA^{xmp} reflect an overall loss-of-load probability of 5 percent for the Northwest.

Firm Capacity Credit

The second input parameter used to simulate achievement of firm capacity standards is the firm capacity credit for each type of generating resource. The firm capacity credit is often referred to as resource type's peak contribution or its expected availability at the time of peak demand. For a generating resource that is fully dispatchable, the peak contribution is net installed capacity less its forced outage rate. The Council uses a firm capacity credit for thermal resources in the range of 90 to 95 percent of installed capacity (See Appendix I for specific values for each resource type). The Council uses the firm capacity credit of 5 percent for wind resources adopted by the Reliability Forum, and an provisional value of 30 percent for solar photovoltaic resources. For the Pacific Northwest's hydro resources, the Council uses a winter single-hour firm capacity credit of 82 percent on installed capacity for east-side hydro and 83 percent for west-side hydro. 95 percent is used for hydropower in other load resource areas.

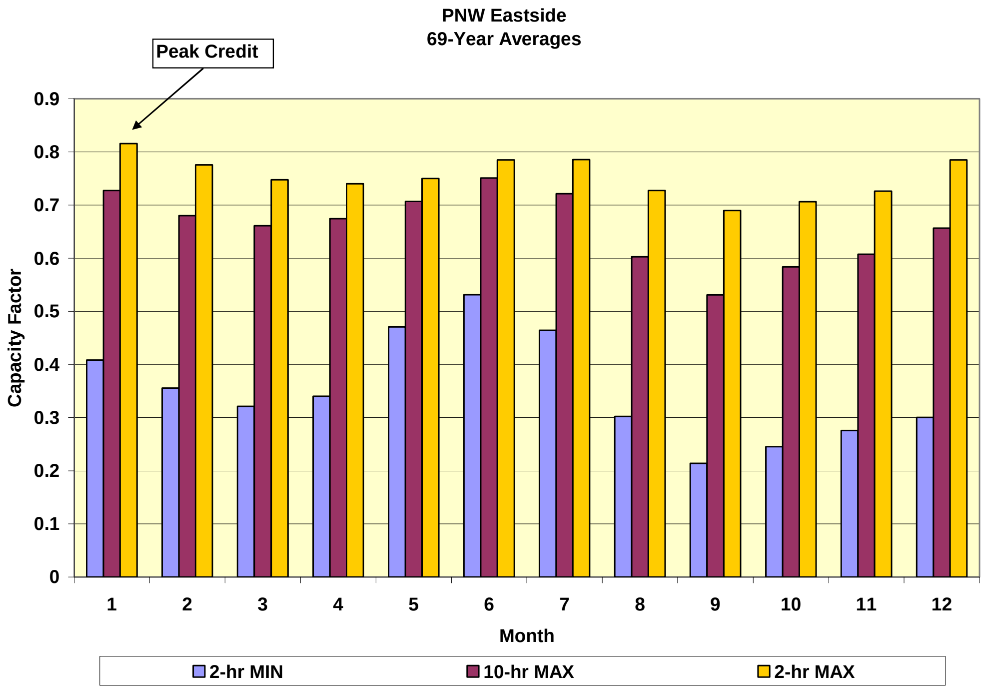
The firm capacity credits for Pacific Northwest hydro resources are based on two-hour sustained peaking capacity estimates developed for the Pacific Northwest Resource Adequacy Forum. Figure D-5 shows the January peaking capability of Pacific Northwest Eastside hydro resources as a function of monthly energy output. On the horizontal axis, the average monthly energy output of these hydro resources can be seen to range from 11,000 to 24,000 megawatts, depending upon streamflow conditions. On the vertical axis, the curve at the top of the chart represents the two-hour sustained peak output of these hydro resources across the range of monthly output. For example, given 1929 streamflows yielding a monthly energy output of 12,000 average megawatts, the east-side hydro resources would be expected to provide roughly 22,000 megawatts of firm capacity over a two-hour peak period.

Figure D-5: Example Calculation of Pacific Northwest Eastside January Sustained Peaking Capacity (1929 streamflow conditions)



The Council has calculated the two-hour sustained peaking capacity credit for both Eastside and Westside hydro resources by month for each of the 69 calendar years in the Pacific Northwest streamflow record. Figure D-6 shows the two-hour sustained peaking capacity for Eastside hydro resources by month. For hydro modeling in AURORA^{xmp}, the Council uses the January values of 82 percent of installed capacity for Eastside hydro resources and 83 percent for Westside hydro resources (derived in a similar manner).

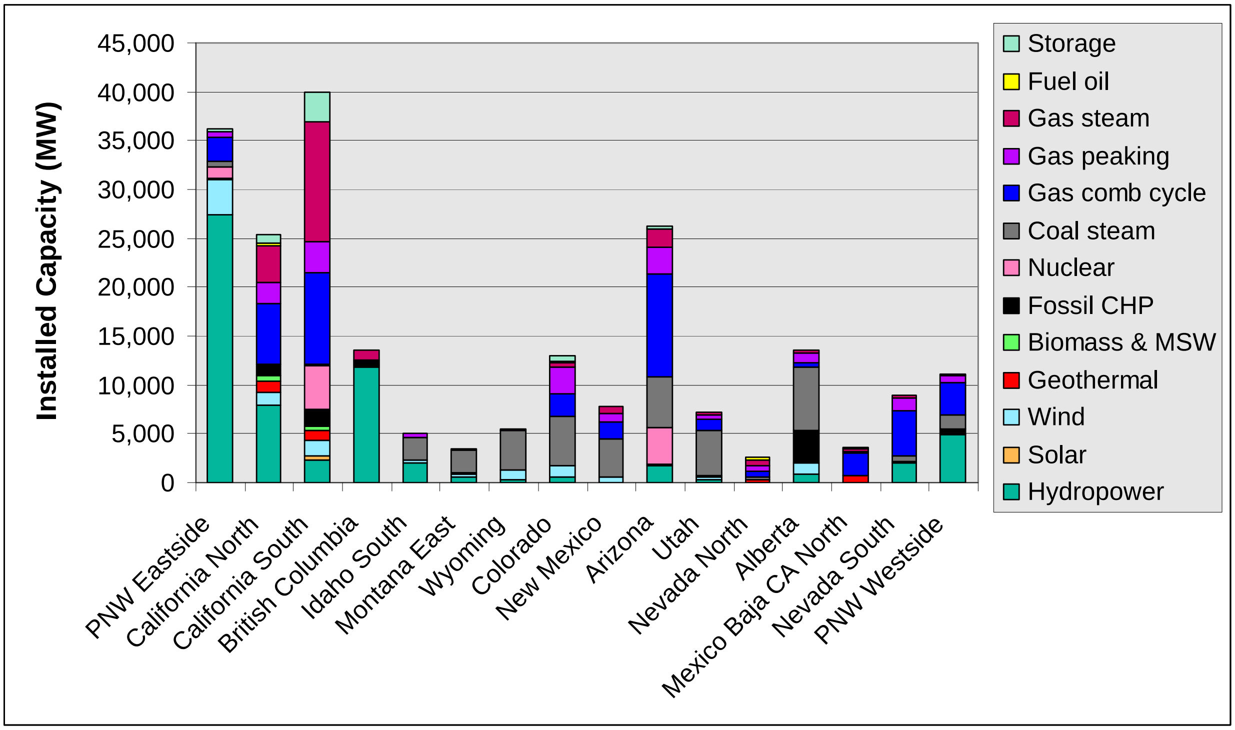
Figure D-6: PNW Eastside Hydropower, 69-year Average



Existing Resources

AURORA^{xmp} capacity expansion studies commence with the generating resources of the existing power system. For purposes of this forecast, "existing resources" are those in operation or under construction as of September 2009. The database of existing resources was updated using WECC data, the Council's database of Northwest power plants, information regarding new power plants maintained by the Council for cost-estimating purposes and other sources. The existing WECC generating resource mix by load-resource area is illustrated in Figure D-7.

Figure D-7: 2009 Resource Mix by Load-resource Area



New Resource Options

The first step in developing the forecast is to run AURORA^{xmp} using the model's long-term resource optimization logic to produce a forecast of resource additions and retirements. New resource options are provided for the model to draw upon for this purpose. Resources, such as biogas, available in relatively small quantity were omitted from the set of resource options because their absence is not expected to significantly affect future power prices and because most of these resources are expected to be developed in response to state renewable portfolio standards.

The cost and operating characteristics of the new resource options are based on the assessment of new resource options prepared by the Council for the Pacific Northwest as described in Chapter 6 and Appendix I of this plan. The output of combustion turbine-based technologies was adjusted to reflect the elevation of representative sites within the various load-resource areas. Also, the capacity factors of solar and wind resource options were adjusted to reflect typical performance within the various load-resource areas. Representative solar parabolic trough and solar photovoltaic plant hourly output was developed using the NREL Solar Advisor Model[5], as described in Appendix I. Hourly wind output estimates were developed from the hourly wind profiles for representative wind resource areas compiled by WECC staff from the National Renewable Engineering Laboratory mesoscale wind data base.

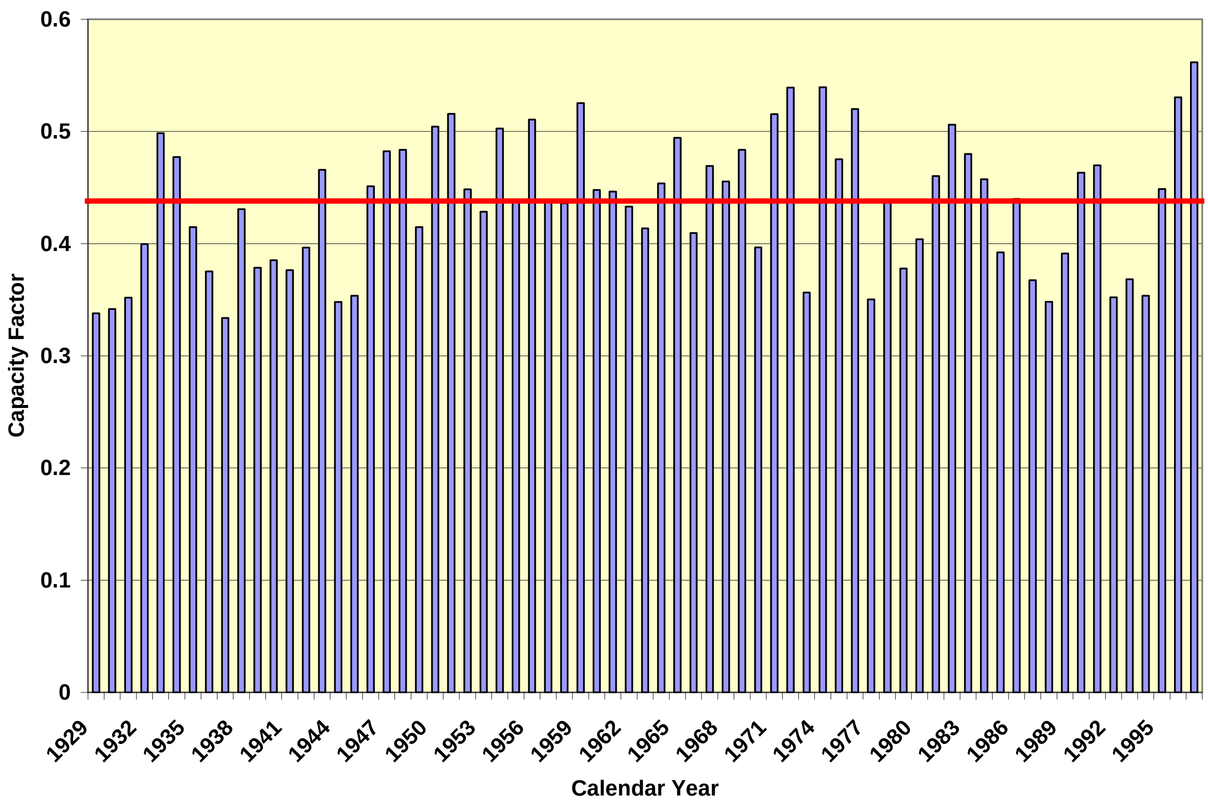
Characteristics of the new resource options used for this forecast are summarized in Table D-2. Additional information regarding these options is provided in Chapter 6 and Appendix I.

[5] www.nrel.gov/analysis/sam/

Pacific Northwest Hydro Modeling

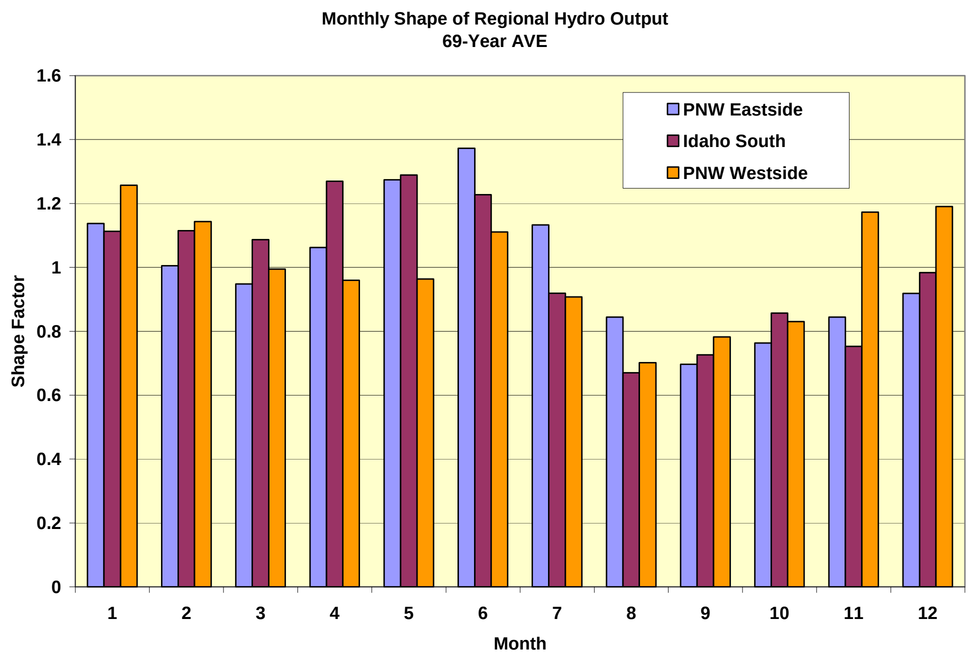
Pacific Northwest modified streamflow data is available for the period September 1928 through August 1998. The Council uses its GENESYS model to estimate the hydroelectric generation that would be expected from this streamflow record given today's level of river system development and environmental protection. To simulate Pacific Northwest hydroelectric generation in AURORA^{xmp}, annual average capacity factors are calculated for the hydro resources of the Pacific Northwest Eastside; Pacific Northwest Westside; and Southern Idaho load-resource areas. Figure D-8 shows the annual capacity factors of the Pacific Northwest Eastside hydro resources given the modified streamflow record for the period January 1929 through December 1997. The 69-year average capacity factor is 44 percent of nameplate capacity.

Figure D-8: Annual Capacity Factor of Pacific Northwest Eastside Hydropower Resources



The seasonality of hydropower production is modeled in AURORA^{xmp} by use of monthly shaping factors. The average monthly hydropower output for the 69-year annual record is shown in Figure D-9.

Figure D-9: Northwest hydropower monthly shape factors, 69 Year Avg.



State Renewable Portfolio Standards

Renewable resource portfolio standards (RPS) mandating the development of certain types and amounts of resources have been adopted by eight states within the WECC: Arizona, California, Colorado, Montana, New Mexico, Nevada, Oregon and Washington[6]. In addition, British Columbia has adopted an energy plan with conservation and renewable energy goals equivalent to an aggressive RPS. Important characteristics of the state renewable portfolio standards are shown in table D-4. State RPS laws are complex with great variation between states and are often amended. Current information regarding state renewable portfolio standards are documented at www.dsireusa.org. The applicable elements of the British Columbia energy policy, adopted in 2007 can be summarized as a series of paraphrased policy statements:

- All new electricity generation projects shall have zero greenhouse gas emissions
- All existing thermal shall have zero greenhouse gas emissions by 2016.
- Renewable energy sources will continue to account for at least 90 % of generation.
- No nuclear power.
- 50% of new resource needs through 2020 will be met by conservation.

Mandatory development of low variable-cost renewable resources can significantly affect wholesale power prices and the need for discretionary resources. A forecast of the types of renewable resources that may be developed and the success in achieving the targets is needed for

[6] Utah's *Energy Resource and Carbon Emission Reduction Initiative* adopted in 2008 has characteristics of a renewable portfolio standard, but mandates acquisition of qualifying resources only if cost-effective. Because resource acquisitions based on cost-effectiveness are simulated by the capacity expansion logic of the AURORA[xmp®] Electricity Market Model used for the wholesale power price forecast was not forecast.

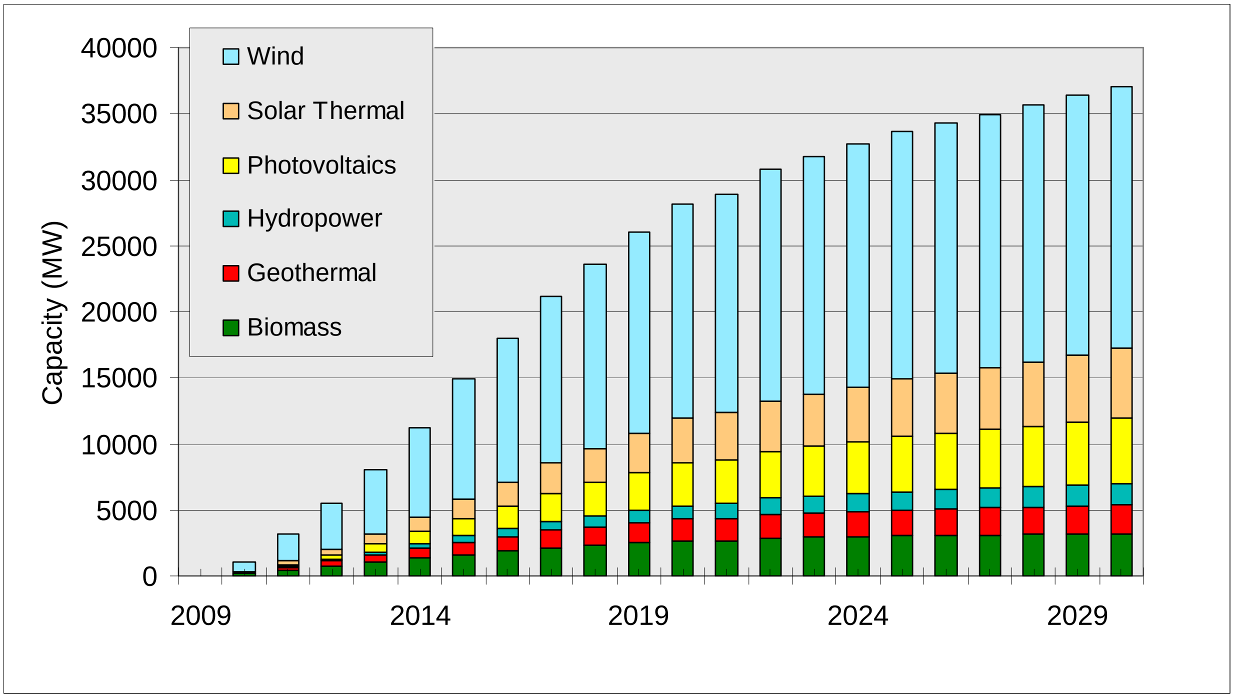
the wholesale power price forecast and the resource portfolio analysis. The resulting estimate of need for new renewable energy to fully meet state RPS obligations is provided in Table D-43

Because of price caps, observed lags in some states, and the increasing cost and difficulty of securing qualifying resources as demand increases, acquisition of qualifying resources is unlikely to meet targets in some states. This forecast assumes 95 percent achievement of standards (i.e, 95 percent of the new energy of Table D-3). All potentially qualifying existing plants are assumed to be credited. Energy-efficiency measures, in states where credited, are assumed to be employed to the extent allowed.

RPS obligations will be met by a mix of new resources, determined by state-specific resource eligibility criteria, new resource availability, resource cost, policies governing out-of-state resources, resource set-asides and special credit and other factors. New RPS resource development in the near-term was assumed to resemble the composition of recent RPS resource development. Development is assumed to shift over time toward locally abundant, but relatively undeveloped resources such as solar thermal as the cost-effectiveness of these resources improves. Figure D-10 illustrates the assumed incremental capacity additions needed to provide 95 percent of the cumulative energy requirements of Table D-4.

As a simplifying assumption, the Council assumed that all new RPS resource requirements would be met in-state, though it is clear that states such as California, with substantial need for qualifying RPS resources, will secure much of its RPS needs from out-of-state sources.

Figure D-10: WECC Cumulative Renewable Portfolio Standard Capacity Additions



Fuel Prices

The coal and natural gas prices used for the draft forecast are based on the Council's fuel price forecast, described in Appendix A.

The Council forecasts the variable and fixed cost of coal delivered to each load-resource area using a reference mine-mouth price plus transportation cost. Powder River Basin (PRB) coal is the reference. The variable delivered coal cost is the sum of the mine-mouth price, plus the variable cost of transportation to each load-resource area. The variable costs of transportation are based on average coal transportation rates and average shipment distances from Wyoming to each load-resource area.

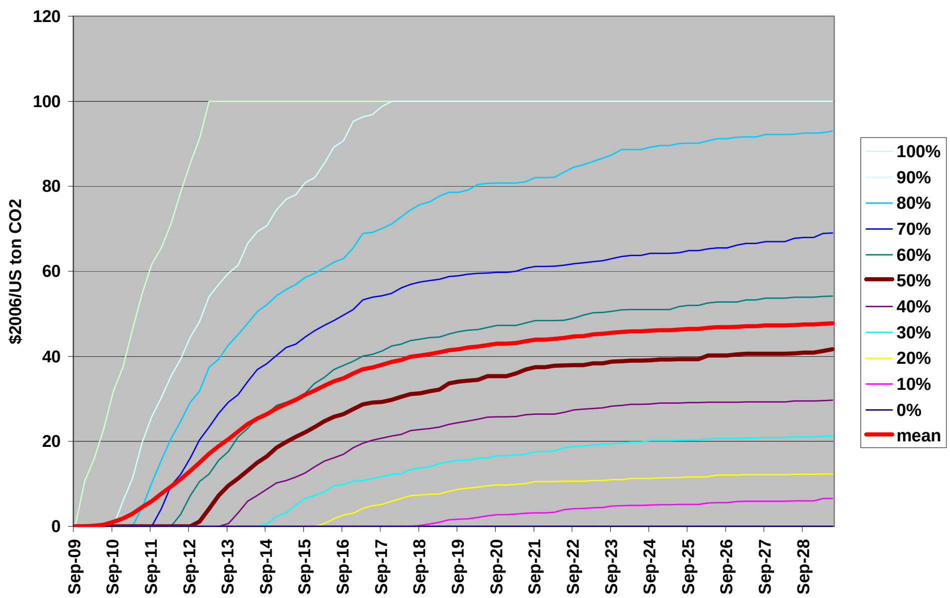
The Council's underlying forecast of natural gas prices is described in Appendix A. Development of the estimated delivered cost of natural gas for each load-resource area is described in Appendix A.

The nuclear and biomass fuel price forecasts are described in Appendix I.

Carbon Dioxide Prices

The Council's studies use a fuel carbon content tax as a proxy for the cost of carbon dioxide control, whether it be by cap and trade allowances or by tax. The CO_2 allowance cost values used for this forecast are derived from the range of possible CO_2 costs developed for the resource portfolio risk analysis (Figure D-11).

Figure D-11: Decile chart of forecast CO_2 prices



Source: workbook "New CO2 Distribution 090425.xls", chart "Carbon Distribution"

The Base case forecast used the mean value of CO_2 prices from the $0 - 100 Carbon Risk Case of the resource portfolio analysis. This price series is depicted by the heavy red line in Figure D-11. The Low CO_2 (price) and Low Scenario cases used the 90% probability of exceedance prices (10% decile in Figure D-11). The High CO_2 (price) and High Scenario cases used the 10% probability of exceedance prices (90 percent decile in Figure D-11). The year-by-year values are provided in Table D-5.

Carbon Dioxide Emission Performance Standards

California, Montana, Oregon and Washington have established CO_2 emission performance standards for new baseload generating plants. The intent of the Oregon and Washington standards is to limit the CO_2 production of new baseload facilities to that of a contemporary combined-cycle gas turbine power plant fuelled by natural gas (about 830 lbCO_2/MWh). The California standard is less restrictive, allowing production of 1100 lbCO_2/MWh - a level that would allow baseload operation of many of the simple-cycle aeroderivative gas turbines installed in that state and require sequestration of about 50% of the CO_2 production of a coal-fired plant. Although the 1100 lbCO_2/MWh California standard was adopted by Washington as the initial standard, it seems likely that the Washington standard will be reduced in administrative review to a level approximating 830 lbCO_2/MWh, as the legislation clearly states that the standard is intended to represent the average rate of emissions of new natural gas combined-cycle plants. The Montana standard does not set an explicit carbon dioxide production limit, but rather mandates capture and sequestration of 50 percent of the carbon dioxide production of any new coal-fired generating facility, subject to approval of the state Public Service Commission. Additionally, Idaho has established an indefinite moratorium on coal-fired power plant development and the BC Energy Plan requires any new interconnected fossil fuel generation in the province to have zero net greenhouse gas emissions.

Development of specific resource types within given load-resource areas is controlled through the New Resource data input table as noted in Table D-2. Imports of power, however, from specific types of resources within other load-resource areas cannot be easily controlled in AURORA^{xmp} because contractual paths are not modeled. In the development of the draft forecast, the BC Energy Plan restriction was approximated in by limiting new coal-fired resource options within the BC load-resource area to integrated gasification combined-cycle (IGCC) plants with CO_2 separation and sequestration (CSS). The state performance standards were approximated by limiting new coal-fired resource options within the California, Oregon, and Washington load-resource areas to IGCC plants with CO_2 separation and sequestration and by constraining new conventional coal resource options in peripheral areas to amounts sufficient only to meet native load. In addition, new coal plants were precluded in Idaho because of the moratorium on conventional coal development in that state. The Montana policy that new coal plants capture and sequester 50 percent of CO_2 emissions was not incorporated in this study.

Though initial runs of cases favoring coal showed some development of coal-steam units in several load-resource areas not subject to performance standards, no IGCC units with CSS were developed, probably because of the high cost of these plants relative to other options. The IGCC option was subsequently removed to expedite later runs. Furthermore, because development of coal-steam units in cases favoring coal in areas peripheral to areas having restrictions on coal generation did not exceed load growth of the peripheral areas, coal-steam units were therefore retained as a new resource option in these areas.

THE BASE CASE FORECAST

Resource Build-out and Load-resource Balances

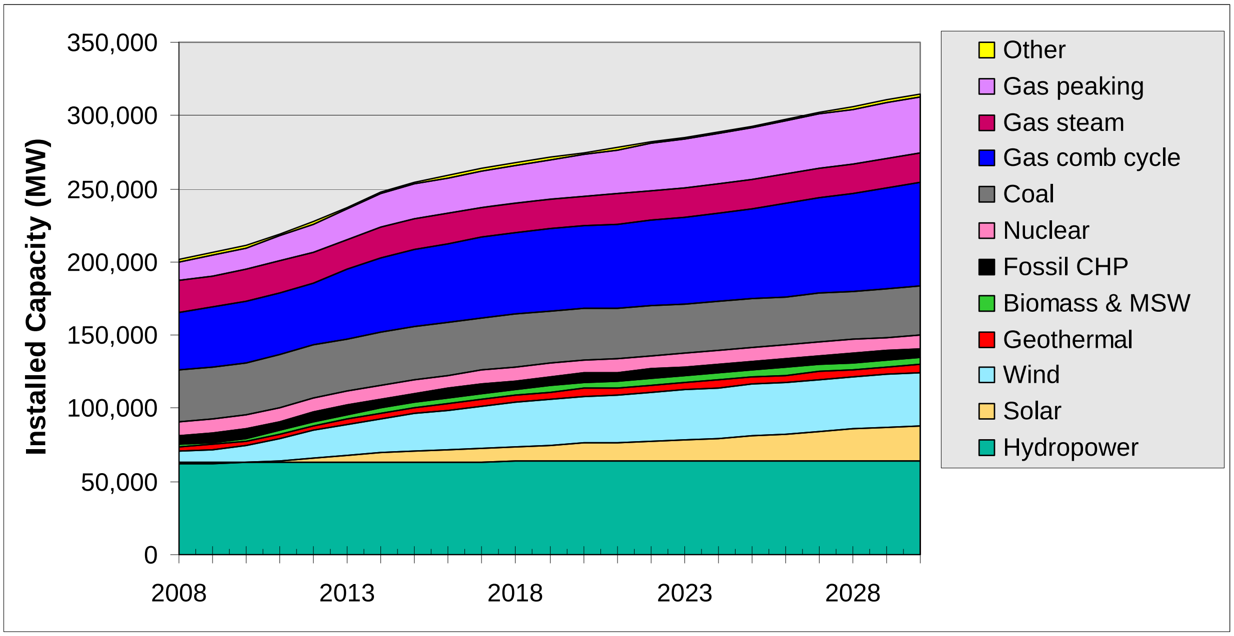
The first step in preparing a forecast using AURORA^{xmp} is to run a long-term system expansion study to develop an economically optimal mix of resources to serve the forecasted load and maintain reserve margins. Each year of the study period, AURORA^{xmp} tests the economic viability of each existing resource by calculating its levelized present value based on forward costs and revenues. Resources not meeting a minimum present value criterion for retirement (Set at $10,000/MW net loss for these forecasts) are retired. Likewise, the potential economic viability of available new resource options are tested and those meeting a net present value hurdle (Set at $10,000/MW net revenue for these forecasts) are added. The system expansion runs are repeated with incremental changes to the resource mix until the present value system price stabilizes. This typically requires 35 to 70 iterations.

The Base case forecast capacity build-out was developed through an incremental process of updating the forecast developed for the draft plan. This principal updates included the following:

- Update AURORAxmp to Version 9.6.1011.
- Update forecast of general inflation
- Update CO_2 price forecast
- Update forced and scheduled outage rates
- Update inventory of WECC generating resources
- Update the natural gas price forecast
- Update the base year loads and load growth forecasts
- Update the forecast of RPS resource development
- Incorporate representative hourly output for wind and solar resources
- Update new resource costs using revised discount rates and financing costs

The resulting WECC installed capacity by resource type is shown in Figure D-12. The expansion of solar, wind, geothermal and biomass capacity is largely a result of RPS resource development, augmented in the latter portion of the forecast period by economic development of discretionary solar thermal and wind. Economically-driven additions of combined-cycle and peaking gas turbines are also evident. Discretionary resource additions in the Northwest consist of 570 megawatts of peaking gas turbines.

Figure D-12: WECC Capacity Expansion - Base Case



Not as evident at the scale of the chart are economic retirements of coal, gas-steam and older combined-cycle capacity. Northwest economic retirements include 2,540 megawatts of coal steam units and 1,600 megawatts of older, less-efficient combined-cycle units.

Firm capacity balances for the base case are shown in Figure D-13. WECC reserve margins are maintained largely through addition of gas combined-cycle and gas peaking units (Figure D-12), with smaller contributions from RPS hydro, geothermal, biomass and solar capacity additions. The Northwest reserve margin remains stable at current levels through 2019 and then begins to decline to adequacy standard levels as coal units are retired. Periodic additions of gas peaking units help maintain Northwest reserves.

Energy load-resource balances for the base case are shown in Figure D-14. RPS resource additions and economic development of combined-cycle and gas peaking capacity maintain ample firm energy balances throughout the forecast period for WECC as a whole. In the Northwest, low load growth net of conservation, RPS resource additions and economic development of gas peaking capacity maintain adequate energy reserves even with retirement of coal and older gas units.

Figure D-13: Firm Capacity Balance - Base Case

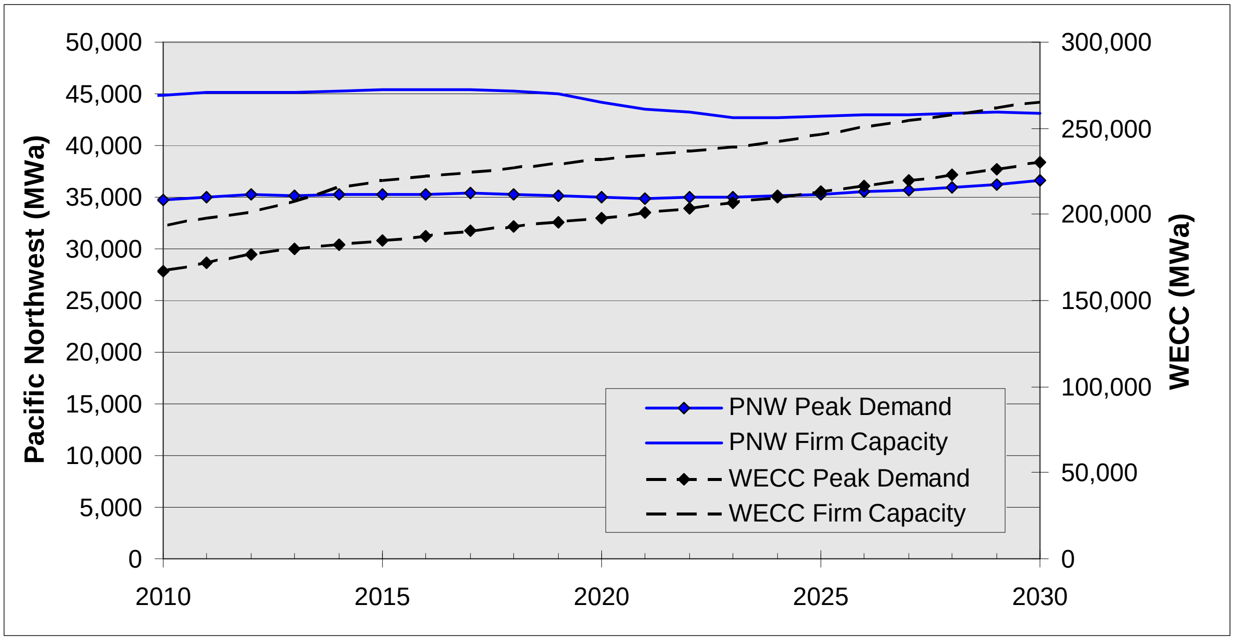
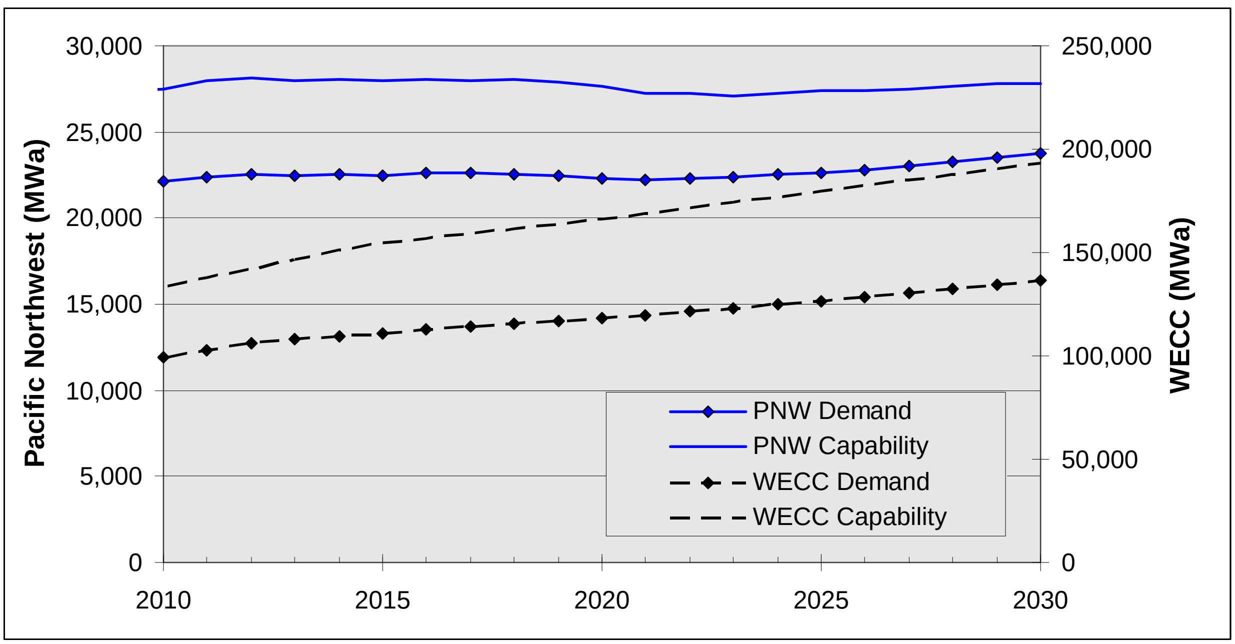


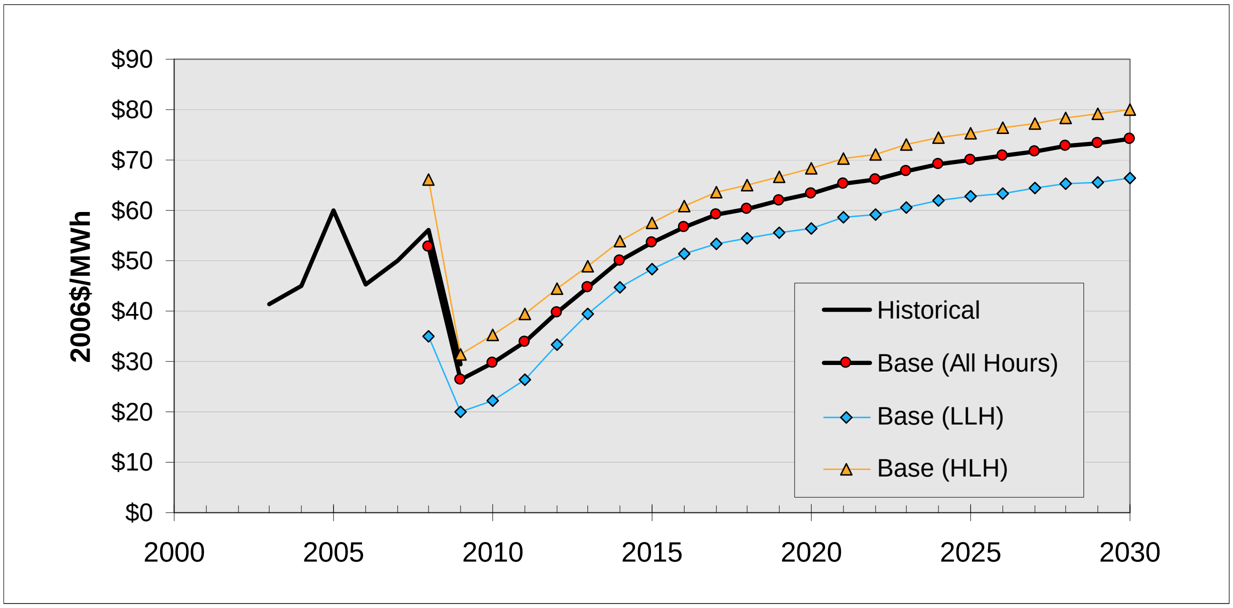
Figure D-14: Energy Load-resource Balance - Base case



Base Case Price Forecast

The Council's forecast of Mid-Columbia trading hub electricity prices, levelized for the period 2010 through 2029, is $55.50 per megawatt-hour (in year 2006 dollars). Figure D-15 shows recent historical annual average prices and the base case forecast for the Mid-Columbia trading hub. In addition to annual average "all-hour" values, annual average light-load hour and heavy load hour prices are also shown[7]. The 2008 and 2009 historical and forecast average annual prices are well correlated. The values underlying the curves are provided in Table D-6.

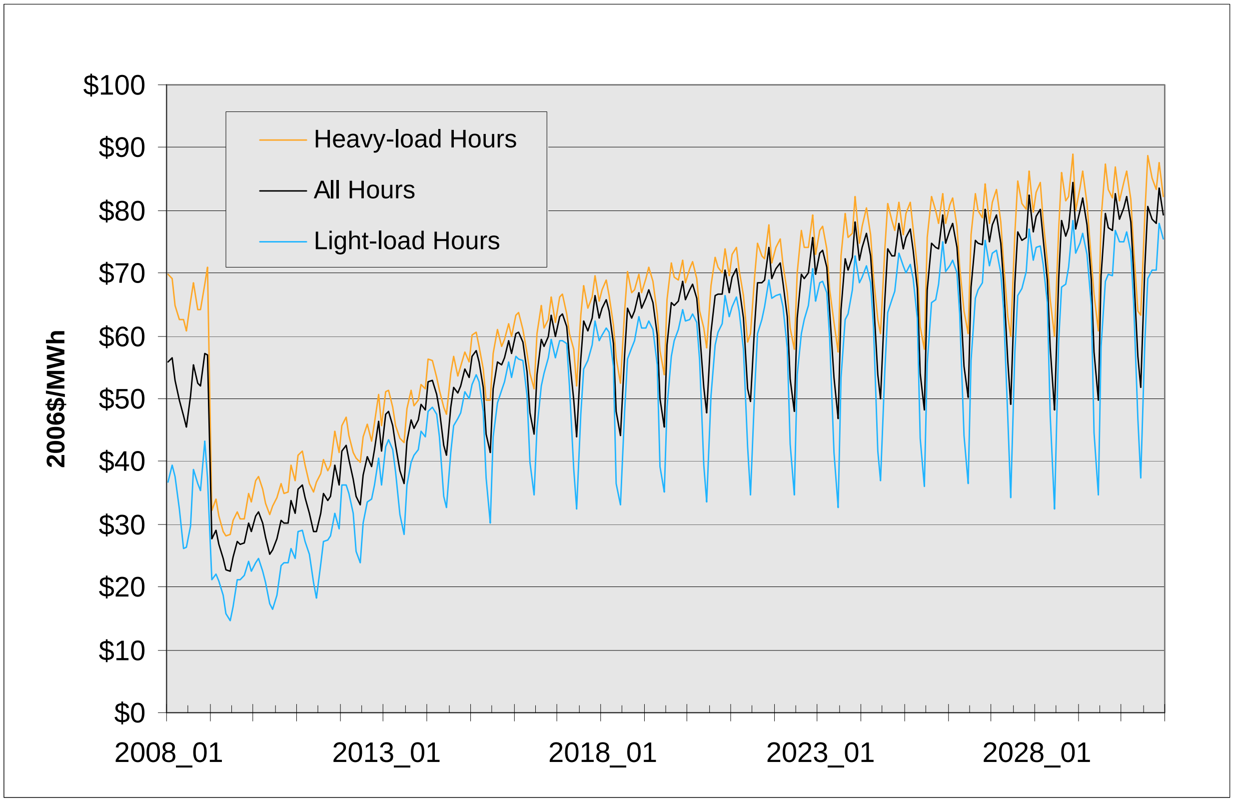
Figure D-15: Annual Average Mid-Columbia Wholesale Power Price Forecast - Base Case



Northwest electricity prices exhibit a seasonal pattern associated with spring runoff in the Columbia River Basin and lower loads as the weather moderates. The forecasts exhibit this pattern when viewed on a monthly average basis. Figure D-16 shows the monthly average heavy-load hours, all hours, and light-load hours prices for the Base forecast. A flattening of light load hour prices during high-runoff, lower load seasons, becomes evident in the mid-term of the forecast period. This is likely attributable to the increasing penetration of low-variable cost, must-run resources. The monthly average prices for the base case forecast are provided in Table D-8.

[7] Heavy load hours are comprised of weekday and Saturday hours 7 through 22.

Figure D-16: Monthly Average Mid-Columbia Wholesale Power Price Forecast - Base Case



SENSITIVITY CASES

Four sensitivity studies and two bounding scenario cases were run. All cases assume 95% achievement of state renewable portfolio standards, average hydropower conditions, medium load growth and achievement of all cost-effective conservation, as assumed for the base case forecast. The changing case assumptions are as follows:

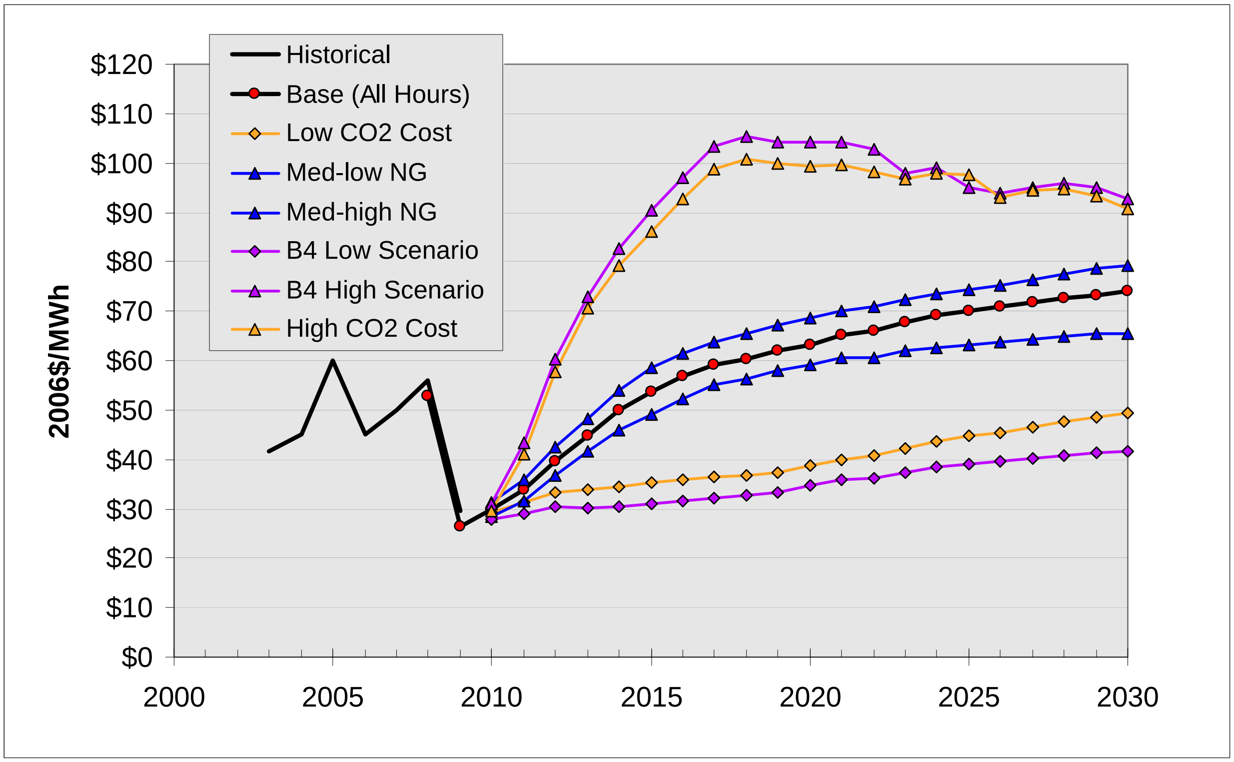
Case	Fuel Prices	CO_2 Cost
Base	Medium Case	Mean of RPM $0 -100 case[8]
Low CO_2 Cost	Medium Case	90% prob. of exceedance decile
High CO_2 Cost	Medium Case	10% prob. of exceedance decile
Medium-Low Natural Gas	Medium-low NG	Mean of RPM $0 -100 case
Medium-High Natural Gas	Medium-high NG	Mean of RPM $0 -100 case
Low Scenario	Medium-low NG	90% prob. of exceedance decile
High Scenario	Medium-high NG	10% prob. of exceedance decile

A capacity expansion study was run for each sensitivity case to simulate economically optimal resource development if the fuel and CO_2 price assumptions of the sensitivity cases held throughout the forecast period.

[8] See Chapter 10.

The results of the sensitivity cases are compared to the Base case and to historical power prices in Figure D-17. Comparing the shape of the power price forecasts with CO_2 price forecast of Figure D-11 clearly demonstrates the significant effect of CO_2 costs on prices. This is particularly evident in the High CO_2 and High Scenario cases. In these cases, prices rise rapidly early in the forecast period as CO_2 prices increase, then stabilize and decline as CO_2 prices reach a steady-state of $100/ton CO_2 and additional low carbon resources are deployed.

Figure D-17: Annual Average Mid-Columbia Wholesale Power Price Forecast - Sensitivity Cases



The apparent extreme sensitivity of the results to CO_2 prices compared to natural gas prices is somewhat misleading. The range of the CO_2 price forecast is much greater than that of the natural gas price forecasts used in the sensitivity studies. This reflects the considerable uncertainty regarding future CO_2 prices.

The results of the two cases incorporating high CO_2 costs also illustrate the ability to adapt to persistently high CO_2 costs. Prices in these cases rise rapidly in response to CO_2 prices, but then decline as more costly coal units and older, less efficient natural gas units are replaced by more efficient gas combined-cycle units and renewables. Greater response to CO_2 costs than shown here is possible. Load growth is fixed in these studies rising prices could be expected to induce additional energy efficiency improvements, further reducing power prices.

AVOIDED RESOURCE COST

The Council's wholesale power price forecast has been used by others as a measure of avoided resource cost. The Council cautions that this price forecast may not be a suitable stand-alone measure of avoided resource costs. The Northwest as a whole enters the forecast period with an energy surplus, and remains so throughout the period because of the addition of resources to meet renewable resource portfolio requirements. Because no discretionary (non-RPS) energy resources are added, the resulting energy prices do not reflect the avoided cost of any new resource. The actual avoided resource costs for the three Northwest states with renewable portfolio standards are the costs of the renewable resources needed to meet RPS requirements, or any capacity additions needed to supply balancing reserves (balancing reserve requirements are not tracked in the AURORA$^{xmp®}$ model). Individual states in the region may have specific requirements, such as PURPA (Public Utilities Regulatory Policies Act) determinations, that are governed by state or federal law or regulations; the Council's recommendations on avoided cost are not intended to supplant those requirements. About 570 megawatts of simple-cycle gas turbines are added in the southern Idaho area to maintain capacity reserves. But because this capacity only contributes incidental energy, even the energy price forecast for the southern Idaho area does not represent an avoided resource cost. The forecast energy market prices can be adjusted to represent avoided resource costs by use of price adders representing the risk premium and capacity value of the specific resource being evaluated. The resulting sum of energy market prices, capacity credit and risk premium represents the avoided cost of the resource in question. This is the approach taken in the Council's planning to establish the value of energy efficiency measures.

NATURAL GAS CONSUMPTION

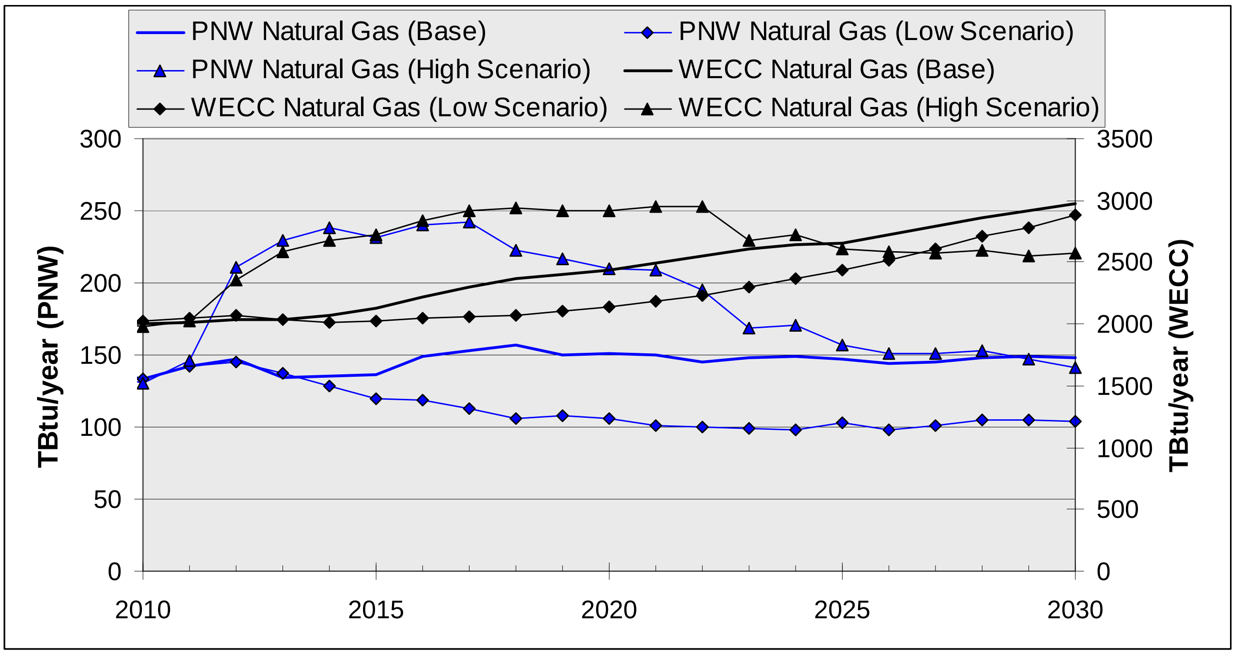
Extensive construction of gas-fired combined-cycle capacity has greatly increased the use of natural gas for power generation in the Western United States since the early 1990s. In the Northwest, gas-fired capacity increased from 1,550 megawatts, representing about 3 percent of regional capacity, to over 9,000 megawatts in 2009, representing 16 percent of regional capacity. This development has been motivated by the introduction of reliable, low emission, high efficiency combined-cycle gas turbine power plants, and generally attractive natural gas prices (despite several relatively short term peaks). This forecast suggests that natural gas-fired plants will continue to supersede coal units as the primary thermal component of the power system. This raises the issue of future gas supply, transportation and storage adequacy. Over the past two decades, increased use of natural gas for power generation has been offset by reduction in industrial demand for gas; however, it is not clear that additional offset can be expected from this source.

Annual natural gas consumption for the Base, High Scenario and Low Scenario cases is shown in Figure D-18. Northwest consumption (blue lines) is plotted against the left-hand axis and WECC consumption (black lines) is plotted against the right-hand axis. The Base case results show consumption for WECC as a whole rising about 43 percent from 2010 through 2030, as natural gas substitutes for coal in response to rising CO_2 prices. The Base case Northwest consumption, however, is nearly flat over the same period, despite retirement of over 2500 megawatts of coal capacity and rising CO_2 prices. Examination of resource dispatch and interzonal transfers in the base case show substantial reduction in net power exports from the Northwest during this period. It appears that construction of new gas combined-cycle units outside of the Northwest (28,000 megawatts of new combined-cycle units are constructed in the Base case - all outside of the Northwest) for purposes of capacity and energy results in reduction of net Northwest exports, allowing the Northwest to maintain energy adequacy without increasing natural gas use.

The Low Scenario shows reduction of natural gas use in the Northwest - probably a result of low load growth (net of conservation), continued coal use, and the additional energy of RPS resources. WECC-wide gas use increases nearly at the same rate as in the Base case. This appears to be due to more rapid rates of load growth outside the Northwest and construction of new gas combined-cycle units in response to low natural gas prices (33,000 megawatts of new combined-cycle units are constructed in the Low Scenario - again all outside of the Northwest).

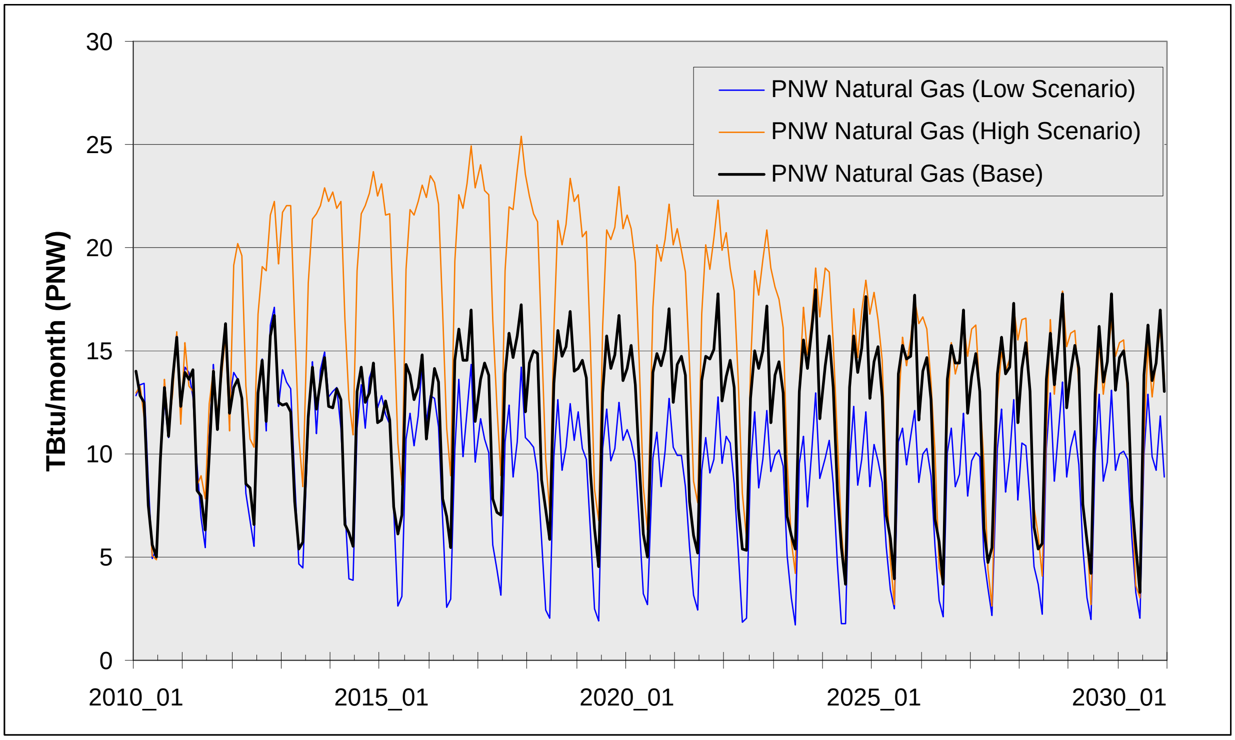
The High Scenario shows rapidly increasing natural gas consumption in the near- to mid-term as CO_2 prices increase - both for the Northwest as well as for WECC as a whole - as dispatch shifts from coal to combined-cycle units. In the longer-term, Northwest gas consumption for power generation returns to 2010 levels as gas combined-cycle units and discretionary renewable resources are constructed outside the Northwest. This allows the Northwest to reduce net exports and retire coal units, yet serve native loads while reducing natural gas usage. Accelerated construction of discretionary renewable resources throughout WECC results in declining gas consumption in the long-term.

Figure D-18: Forecast Annual Natural Gas Consumption for Power Generation



The seasonal pattern of natural gas use affects the configuration of the gas supply system. Even if annual gas demand remains fairly constant, increasing seasonal volatility may require storage capacity to be expanded. Figure D-19 illustrates monthly patterns of natural gas consumption in the Northwest, for the Base, Low Scenario and the High Scenario cases. Seasonal minimums decline in all cases, as a likely result of the increasing penetration of low variable cost RPS resources. These will reduce operation of gas-fired units during the low-load, high-runoff spring months. Seasonal maximums remain fairly constant in the Base case and decline somewhat in the Low Scenario. Seasonal maximums increase rapidly in the near- to mid-term in the High Scenario as dispatch shifts from coal to combined-cycle units, then fall off as Northwest exports decline as a result of capacity additions outside of the Northwest. It is not known whether the existing gas supply system could support the increase in seasonal maxima of the High Scenario case.

Figure D-19: Forecast Northwest Monthly Natural Gas Consumption for Power Generation



CARBON DIOXIDE PRODCTION

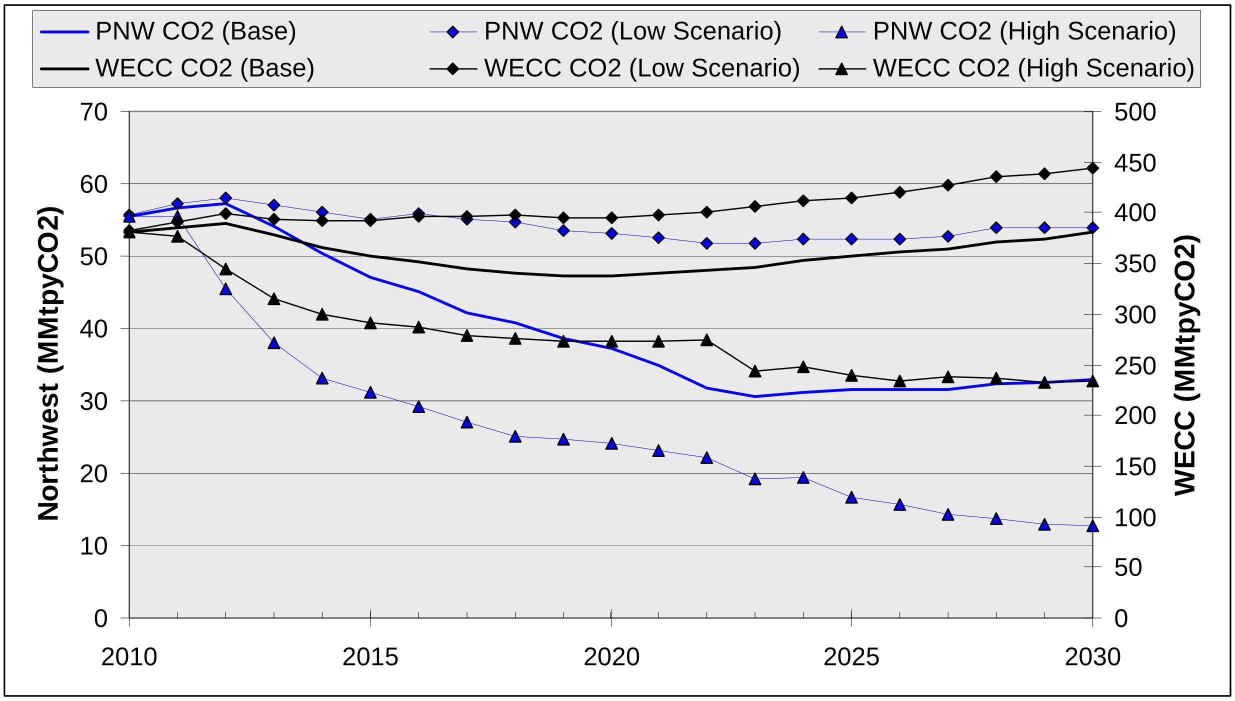
The annual CO_2 production for the Base, Low Scenario and High Scenario cases is shown in Figure D-20. Northwest CO_2 production consistent with Oregon and Washington policy goals is about 35 million tons per year of CO2 (MMtpy) by 2030 and continued reduction through 2050 ("geographic basis" as used in the Council's 2007 CO_2 Footprint study). This is about 60 percent of expected 2010 levels under average water conditions. The equivalent level for WECC as a whole is about 235 MMtpy.

In the base case, Northwest CO_2 production declines to 35 MMtpy by 2021, but commences to rise slowly in 2024, though remaining below 35 MMtpy in 2030. WECC as a whole in the base case, however, declines only to 337 MMtpy by 2019 and rises thereafter to 2010 levels by 2030, well above proposed greenhouse gas target levels.

The High Scenario CO_2 price assumptions are far more effective in reducing CO_2 production, even though natural gas prices are greater in this scenario. Northwest production declines rapidly through the entire period, achieving about 13 MMtpy by 2030, well below target levels. WECC CO_2 production as a whole declines fairly steadily through the period, reaching 60 percent of 2010 levels (234 MMtpy) by 2030.

The Low Scenario results in slowly increasing CO_2 production for WECC as a whole and fairly stable production for the Northwest. The Medium-Low natural gas prices of this scenario and continued acquisition of RPS resources are likely responsible for the low WECC-wide increase in CO_2 production even in the absence of significant CO_2 prices.

Figure D-20: Forecast Annual CO_2 Production from Power Generation



TABULAR DATA

Table D-1: Forecasted Energy Loads for the Load-resource Areas

	AB	AZ	BC	Baja N.	CA N.	CA S.	CO	ID S.	MT E.	NM	NV N.	NV S.	PNWE	PNWW	UT	WY
2008	8413	9380	7141	1195	14914	18647	6077	2596	1028	2362	1384	2944	2362	5357	13960	2732
2009	8332	9293	6893	1170	14536	18245	6042	2367	945	2412	1298	2865	2412	5152	13493	2741
2010	8596	9591	6931	1194	14572	18595	6257	2420	901	2565	1269	2905	2565	5175	13615	2866
2011	9051	10102	7113	1243	14729	19343	6613	2485	892	2785	1265	3006	2785	5220	13743	3058
2012	9530	10640	7300	1294	15007	20121	6989	2501	874	3023	1262	3111	3023	5268	13899	3263
2013	10009	10904	7379	1320	15210	20370	7128	2495	863	3090	1275	3185	3090	5240	13844	3345
2014	10514	11197	7399	1347	15340	20622	7253	2509	863	3152	1274	3255	3152	5258	13905	3431
2015	11010	11496	7289	1374	15465	20875	7376	2512	854	3229	1289	3330	3229	5245	13886	3508
2016	11471	11796	7273	1401	15596	21109	7523	2525	857	3283	1309	3416	3283	5275	13961	3587
2017	11854	12113	7263	1429	15745	21339	7662	2532	854	3341	1321	3484	3341	5272	13949	3643
2018	12189	12422	7256	1458	15883	21580	7808	2530	852	3399	1343	3575	3399	5266	13930	3713
2019	12507	12736	7248	1486	16021	21698	7950	2505	843	3458	1358	3651	3458	5243	13883	3772
2020	12949	13040	7218	1518	16167	21919	8097	2481	836	3505	1375	3736	3505	5210	13792	3844
2021	13376	13334	7204	1551	16311	22134	8249	2482	835	3543	1393	3823	3543	5194	13742	3915
2022	13793	13664	7190	1583	16458	22345	8403	2501	837	3598	1410	3910	3598	5206	13769	3984
2023	14217	13998	7175	1615	16605	22552	8559	2523	839	3651	1429	4001	3651	5222	13808	4056
2024	14662	14336	7159	1648	16753	22752	8718	2555	845	3704	1447	4092	3704	5260	13905	4129
2025	15136	14680	7142	1683	16903	22968	8880	2579	849	3755	1465	4186	3755	5276	13945	4204
2026	15615	15032	7126	1718	17055	23184	9046	2610	854	3807	1484	4283	3807	5310	14031	4280
2027	16107	15397	7111	1754	17207	23400	9214	2646	860	3863	1503	4381	3863	5353	14139	4357
2028	16614	15769	7095	1790	17361	23617	9385	2695	871	3918	1522	4482	3918	5422	14317	4435
2029	17140	16149	7080	1827	17517	23836	9560	2731	876	3973	1541	4585	3973	5462	14420	4515
2030	17683	16538	7064	1865	17674	24059	9738	2776	885	4030	1561	4691	4030	5521	14573	4597

Table D-2: New Resource Options

	Capacity (MW)	Earliest Service	Note
Gas Combined-cycle	415	2013	
Aeroderivative GT	2 x 45	2011	
Wind	100	2011	
MT Wind > PNW (Via Colstrip Transmission Upgrade)	659	2015	Capacity limited by CTS upgrade potential
MT Wind > PNW (New transmission via S. ID)	570	2015	
Advanced Nuclear	1100	2023	
Solar (Parabolic trough)	200	2013	AZ, CA, CO, NM, NV & UT areas only
Coal-steam (Supercritical, no CCS)	400	2017	n/a in BC, CA, ID, MT, OR or WA areas because of policy restrictions
Coal gasification (with 88% CSS)	520	Uncertain	Tested but not selected in the draft forecast, removed for the final forecast because of uncertain availability of sequestration
Solar Photovoltaics	5 x 20 MW	2012	Utility-scale plants

Table D-3: State Renewable Portfolio Standards (September 2009)

	Qualifying Generating Resource Types	Existing Resource Vintage Eligibility	Applicable Providers	Ultimate Target (%sales)
Arizona	Solar, Landfill gas, Wind, Biomass, Hydro, Geothermal, CHP	Jan 1997	IOUs, Coops, Retail Providers	15% by 2025
California	Biomass, Geothermal, MSW, Anaerobic digestion, Small hydro, Tidal, Wave, Ocean Thermal, Biodiesel	Sep 1996 + earlier QF & SPPs	All providers[9]	33% by 2020[10]
Colorado	Solar, Wind, Geothermal, Biomass, Small hydro, bottoming cycle CHP	Not specified	IOU's, larger coops and munis	IOUS: 20% by 2020 Coops & munis: 10% by 2020
Montana	Solar, Landfill Gas, Wind, Biomass, Hydro (10 MW or less), Geothermal, Anaerobic digestion	Jan 2005	IOU's, retail suppliers	15% by 2015
New Mexico	Solar, Wind, Landfill, Biomass, Hydro, Geothermal, "Zero emission technology", Anaerobic digestion	No limit except hydro (July 2007, or later)	IOU's, certain coops	IOUs: 20% by 2020 Coops: 10% by 2020
Nevada	Energy-efficiency, Solar, Landfill gas, Wind, Biomass, Certain hydro, Geothermal, MSW, Tires	No limit	IOU's, retail suppliers	25% by 2025
Oregon	Existing low-impact hydro (50 aMW max per utility); new hydro, wind, solar, ocean, geothermal, non-contaminated biomass	Jan 1995 with exceptions	All	Large: 25% by 2025 Medium: 10% by 2025 Small: 5% by 2025
Washington	Solar, landfill gas, wind, biomass, hydro efficiency improvements and conduit projects, geothermal, anaerobic digestion, tidal, wave, ocean thermal and biodiesel	March 31, 1999	Utilities serving more than 25,000 customers	15% by 2020

[9] Mandated for publically-owned utilities by Executive Order S-21-09 of September 15, 2009.
[10] The California RPS was increased to 33% by 2020 by Executive Order S-21-09 of September 15, 2009.

Table D-4: Estimated Committed and Forecast Incremental RPS Energy Requirements (average megawatts, 100% achievement)

	AZ	BC	CA (33%)	CO	MT	NM	NV11	OR	WA
Committed	87	366	3954	454	6512	111	273	465	520
Cumulative new (100% achievement of standards)									
2010	32	0	425	0	0	0	21	0	0
2011	77	0	1068	0	0	0	63	0	0
2012	115	0	1774	0	19	0	137	0	0
2013	157	0	2416	0	24	112	277	0	0
2014	196	17	2863	280	31	147	339	0	218
2015	240	85	3329	368	37	184	452	0	367
2016	313	136	3401	450	37	214	463	0	511
2017	390	185	3477	537	37	243	496	0	662
2018	471	239	3551	626	37	273	508	0	812
2019	555	296	3602	718	37	304	524	0	958
2020	642	351	3674	813	37	335	537	0	953
2021	733	406	3745	836	37	341	551	0	941
2022	826	462	3816	860	37	346	566	478	939
2023	925	520	3885	885	37	353	580	538	939
2024	1027	579	3954	910	37	359	595	599	941
2025	1134	638	4026	935	38	366	610	662	944
2026	1163	698	4099	961	38	372	626	670	950
2027	1192	758	4171	987	39	379	641	677	956
2028	1223	819	4244	1014	39	385	657	685	965
2029	1254	882	4318	1041	40	392	672	697	977
Total	1341	1248	8272	1495	105	503	945	1162	1497

[11] Nevada values are based on the earlier ultimate target of 20% by 2015.
[12] Overestimate, should be 51MWa. Includes 14 MWa of existing resources that entered service prior to January 2005.

Table D-5: Forecast Carbon Dioxide Prices (2006$/tonCO2)

	Mean of $0 - 100 portfolio Risk analysis	90% Probability of Exceedance (10% decile)	10% Probability of Exceedance (90% decile)
2010	$0.43	$0.00	$0.00
2011	$3.83	$0.00	$15.66
2012	$10.31	$0.00	$37.33
2013	$17.87	$0.00	$54.67
2014	$24.55	$0.00	$67.02
2015	$29.29	$0.00	$77.54
2016	$33.53	$0.00	$86.84
2017	$37.11	$0.00	$96.83
2018	$39.51	$0.06	$100.00
2019	$41.16	$1.19	$100.00
2020	$42.50	$2.27	$100.00
2021	$43.41	$2.97	$100.00
2022	$44.26	$3.67	$100.00
2023	$45.20	$4.45	$100.00
2024	$45.88	$4.94	$100.00
2025	$46.27	$5.16	$100.00
2026	$46.71	$5.49	$100.00
2027	$47.11	$5.88	$100.00
2028	$47.34	$5.96	$100.00
2029	$47.64	$5.96	$100.00
2030	$47.64	$5.96	$100.00

Table D-6: Annual Average Mid-Columbia Wholesale Power Prices - Base Case Forecast (2006$/MWh)

	On-peak	Off-peak	All Hours
2010	$35	$22	$30
2011	$39	$26	$34
2012	$45	$33	$40
2013	$49	$39	$45
2014	$54	$45	$50
2015	$58	$48	$54
2016	$61	$51	$57
2017	$64	$53	$59
2018	$65	$54	$60
2019	$67	$56	$62
2020	$68	$57	$63
2021	$70	$59	$65
2022	$71	$59	$66
2023	$73	$61	$68
2024	$75	$62	$69
2025	$75	$63	$70
2026	$76	$63	$71
2027	$77	$64	$72
2028	$78	$65	$73
2029	$79	$65	$73
2030	$80	$66	$74

Table D-7: Monthly Average Mid-Columbia Wholesale Power Prices - Base Case Forecast (2006$/MWh)

Month	Heavy Load Hours	Light Load Hours	All Hours	Month	Heavy Load Hours	Light Load Hours	All Hours
Jan-2010	$37.03	$23.87	$31.23	Jan-2015	$60.08	$52.16	$56.76
Feb-2010	$37.54	$24.62	$32.00	Feb-2015	$60.60	$53.93	$57.74
Mar-2010	$35.65	$22.57	$30.16	Mar-2015	$58.24	$52.62	$55.76
Apr-2010	$33.30	$20.70	$27.98	Apr-2015	$54.71	$48.00	$51.88
May-2010	$31.43	$17.43	$25.26	May-2015	$49.77	$37.33	$44.29
Jun-2010	$32.82	$16.41	$25.89	Jun-2015	$49.81	$30.17	$41.52
Jul-2010	$34.27	$18.70	$27.74	Jul-2015	$57.21	$43.87	$51.61
Aug-2010	$36.41	$23.51	$30.72	Aug-2015	$61.08	$49.26	$55.87
Sep-2010	$34.95	$23.79	$30.24	Sep-2015	$58.44	$51.46	$55.49
Oct-2010	$35.06	$23.81	$30.10	Oct-2015	$59.36	$52.62	$56.53
Nov-2010	$39.52	$26.16	$33.88	Nov-2015	$61.98	$55.81	$59.24
Dec-2010	$36.85	$24.51	$31.68	Dec-2015	$59.86	$53.47	$57.18
Jan-2011	$40.88	$28.93	$35.61	Jan-2016	$63.19	$56.68	$60.32
Feb-2011	$41.58	$29.16	$36.26	Feb-2016	$63.83	$56.22	$60.59
Mar-2011	$39.36	$27.19	$34.26	Mar-2016	$60.98	$56.13	$58.94
Apr-2011	$36.55	$25.17	$31.75	Apr-2016	$57.18	$50.47	$54.35
May-2011	$35.07	$20.72	$28.74	May-2016	$54.05	$39.90	$47.81
Jun-2011	$36.67	$18.16	$28.85	Jun-2016	$51.62	$34.59	$44.43
Jul-2011	$38.05	$23.67	$31.71	Jul-2016	$60.41	$45.33	$53.76
Aug-2011	$40.36	$27.30	$34.88	Aug-2016	$64.97	$51.95	$59.51
Sep-2011	$38.43	$27.44	$33.79	Sep-2016	$61.27	$54.07	$58.23
Oct-2011	$39.38	$28.15	$34.43	Oct-2016	$62.54	$56.43	$59.85
Nov-2011	$44.77	$31.86	$39.32	Nov-2016	$66.21	$59.35	$63.31
Dec-2011	$41.45	$29.25	$36.33	Dec-2016	$62.26	$56.54	$59.86
Jan-2012	$45.76	$36.30	$41.59	Jan-2017	$66.27	$59.13	$63.12
Feb-2012	$47.07	$36.22	$42.46	Feb-2017	$66.64	$59.23	$63.46
Mar-2012	$44.17	$35.02	$40.33	Mar-2017	$63.44	$58.74	$61.47
Apr-2012	$41.42	$31.82	$37.15	Apr-2017	$60.32	$51.94	$56.59
May-2012	$40.61	$25.68	$34.35	May-2017	$57.86	$38.73	$49.84
Jun-2012	$39.82	$23.91	$33.10	Jun-2017	$52.13	$32.53	$43.85
Jul-2012	$43.93	$30.18	$37.87	Jul-2017	$63.18	$47.53	$56.28
Aug-2012	$45.99	$33.51	$40.75	Aug-2017	$67.95	$54.72	$62.40
Sep-2012	$43.33	$34.04	$39.20	Sep-2017	$64.45	$56.00	$60.88
Oct-2012	$46.07	$36.16	$41.91	Oct-2017	$66.16	$58.52	$62.79
Nov-2012	$50.63	$40.51	$46.36	Nov-2017	$69.53	$62.28	$66.47
Dec-2012	$45.81	$36.29	$41.61	Dec-2017	$65.45	$59.30	$62.74
Jan-2013	$51.18	$42.23	$47.43	Jan-2018	$67.31	$60.17	$64.32
Feb-2013	$51.39	$43.56	$48.04	Feb-2018	$69.01	$61.33	$65.72
Mar-2013	$48.56	$41.90	$45.62	Mar-2018	$66.55	$60.48	$64.01
Apr-2013	$45.73	$38.26	$42.58	Apr-2018	$61.68	$55.24	$58.82
May-2013	$43.62	$31.59	$38.57	May-2018	$56.49	$36.40	$48.06
Jun-2013	$42.94	$28.45	$36.50	Jun-2018	$52.42	$33.00	$44.22
Jul-2013	$48.33	$36.27	$43.27	Jul-2018	$64.03	$48.01	$56.97
Aug-2013	$51.46	$39.92	$46.62	Aug-2018	$70.33	$56.27	$64.43
Sep-2013	$48.86	$40.98	$45.36	Sep-2018	$66.87	$58.00	$62.93
Oct-2013	$49.86	$41.95	$46.54	Oct-2018	$67.31	$59.18	$63.90
Nov-2013	$52.34	$44.86	$49.18	Nov-2018	$69.76	$63.16	$66.97
Dec-2013	$51.48	$43.99	$48.18	Dec-2018	$66.90	$61.29	$64.42
Jan-2014	$56.23	$48.05	$52.80	Jan-2019	$69.21	$61.35	$65.92
Feb-2014	$56.08	$48.76	$52.94	Feb-2019	$70.97	$62.46	$67.32
Mar-2014	$53.29	$47.49	$50.74	Mar-2019	$68.68	$61.03	$65.31
Apr-2014	$51.33	$44.02	$48.24	Apr-2019	$63.53	$55.35	$60.08
May-2014	$48.55	$34.47	$42.64	May-2019	$57.68	$39.13	$49.90
Jun-2014	$47.62	$32.69	$40.98	Jun-2019	$53.90	$35.12	$45.55
Jul-2014	$53.98	$41.37	$48.69	Jul-2019	$65.78	$48.55	$58.55
Aug-2014	$56.66	$45.69	$51.82	Aug-2019	$71.72	$56.71	$65.42
Sep-2014	$53.65	$46.88	$50.79	Sep-2019	$69.42	$55.15	$62.09
Oct-2014	$55.28	$47.74	$52.12	Oct-2019	$68.85	$55.26	$62.24
Nov-2014	$57.53	$51.05	$54.65	Nov-2019	$71.99	$55.37	$62.39
Dec-2014	$55.75	$49.91	$53.30	Dec-2019	$68.40	$55.48	$62.54

Month	Heavy Load Hours	Light Load Hours	All Hours	Month	Heavy Load Hours	Light Load Hours	All Hours
Jan-2020	$70.64	$62.70	$67.31	**Jan-2025**	$79.56	$70.15	$75.62
Feb-2020	$71.90	$63.42	$68.30	**Feb-2025**	$81.34	$71.36	$77.06
Mar-2020	$69.04	$62.17	$66.01	**Mar-2025**	$77.01	$69.21	$73.57
Apr-2020	$64.03	$56.00	$60.64	**Apr-2025**	$70.87	$62.86	$67.49
May-2020	$61.37	$39.42	$51.69	**May-2025**	$61.44	$43.65	$53.98
Jun-2020	$58.08	$33.57	$47.73	**Jun-2025**	$57.81	$35.95	$48.09
Jul-2020	$68.00	$50.48	$60.65	**Jul-2025**	$75.64	$55.60	$67.23
Aug-2020	$72.63	$58.56	$66.43	**Aug-2025**	$82.11	$65.37	$74.73
Sep-2020	$71.01	$60.50	$66.57	**Sep-2025**	$80.01	$65.82	$74.02
Oct-2020	$70.02	$62.03	$66.67	**Oct-2025**	$77.98	$68.23	$73.89
Nov-2020	$73.77	$66.41	$70.50	**Nov-2025**	$82.62	$74.94	$79.21
Dec-2020	$69.70	$63.14	$66.95	**Dec-2025**	$78.01	$70.38	$74.81
Jan-2021	$72.98	$64.67	$69.32	**Jan-2026**	$80.82	$71.28	$76.82
Feb-2021	$74.00	$66.14	$70.63	**Feb-2026**	$82.08	$72.14	$77.82
Mar-2021	$70.59	$64.06	$67.85	**Mar-2026**	$77.45	$70.04	$74.18
Apr-2021	$66.52	$57.89	$62.87	**Apr-2026**	$70.98	$63.52	$67.83
May-2021	$58.94	$42.40	$51.65	**May-2026**	$63.89	$44.26	$55.23
Jun-2021	$60.40	$34.78	$49.58	**Jun-2026**	$60.46	$36.38	$50.29
Jul-2021	$69.79	$51.86	$62.27	**Jul-2026**	$76.12	$56.02	$67.69
Aug-2021	$74.87	$60.46	$68.52	**Aug-2026**	$82.75	$65.92	$75.33
Sep-2021	$72.74	$62.63	$68.47	**Sep-2026**	$80.06	$67.36	$74.70
Oct-2021	$72.28	$64.58	$68.88	**Oct-2026**	$78.90	$68.36	$74.48
Nov-2021	$77.67	$69.00	$74.01	**Nov-2026**	$84.20	$75.31	$80.25
Dec-2021	$71.56	$65.92	$69.19	**Dec-2026**	$77.85	$71.15	$75.04
Jan-2022	$74.08	$66.35	$70.68	**Jan-2027**	$81.23	$73.26	$77.72
Feb-2022	$75.43	$66.72	$71.70	**Feb-2027**	$83.44	$73.61	$79.23
Mar-2022	$71.36	$64.64	$68.54	**Mar-2027**	$78.14	$70.10	$74.77
Apr-2022	$66.89	$58.08	$63.17	**Apr-2027**	$71.87	$64.49	$68.75
May-2022	$61.24	$42.76	$53.10	**May-2027**	$63.12	$46.86	$55.95
Jun-2022	$57.88	$34.58	$48.04	**Jun-2027**	$59.99	$34.25	$49.12
Jul-2022	$69.96	$53.78	$62.83	**Jul-2027**	$76.32	$57.34	$68.36
Aug-2022	$76.75	$60.43	$69.91	**Aug-2027**	$84.59	$66.39	$76.56
Sep-2022	$74.06	$62.67	$69.25	**Sep-2027**	$81.07	$67.47	$75.33
Oct-2022	$74.12	$64.79	$70.01	**Oct-2027**	$80.16	$70.20	$75.77
Nov-2022	$79.24	$70.65	$75.61	**Nov-2027**	$86.26	$77.00	$82.35
Dec-2022	$72.92	$65.53	$69.82	**Dec-2027**	$79.66	$72.05	$76.47
Jan-2023	$76.88	$68.57	$73.21	**Jan-2028**	$82.92	$74.03	$79.00
Feb-2023	$77.53	$68.73	$73.76	**Feb-2028**	$84.48	$74.27	$80.13
Mar-2023	$73.79	$66.91	$70.90	**Mar-2028**	$78.45	$71.33	$75.46
Apr-2023	$67.26	$59.66	$63.88	**Apr-2028**	$71.79	$65.28	$68.89
May-2023	$62.20	$41.40	$53.48	**May-2028**	$65.77	$47.27	$58.02
Jun-2023	$57.37	$32.56	$46.90	**Jun-2028**	$59.82	$32.53	$48.30
Jul-2023	$72.73	$53.43	$64.22	**Jul-2028**	$76.97	$59.33	$69.19
Aug-2023	$79.51	$62.52	$72.38	**Aug-2028**	$86.02	$67.69	$78.33
Sep-2023	$75.72	$63.52	$70.57	**Sep-2028**	$81.55	$68.26	$75.94
Oct-2023	$76.44	$67.40	$72.46	**Oct-2028**	$82.30	$70.98	$77.31
Nov-2023	$82.26	$72.80	$78.26	**Nov-2028**	$88.89	$78.48	$84.49
Dec-2023	$74.81	$68.49	$72.02	**Dec-2028**	$79.97	$73.24	$77.00
Jan-2024	$77.58	$69.35	$74.13	**Jan-2029**	$83.56	$74.84	$79.90
Feb-2024	$80.30	$71.12	$76.39	**Feb-2029**	$86.19	$76.25	$81.93
Mar-2024	$76.20	$68.48	$72.79	**Mar-2029**	$81.10	$72.87	$77.65
Apr-2024	$69.36	$61.59	$66.08	**Apr-2029**	$72.08	$64.95	$68.91
May-2024	$62.66	$41.75	$53.89	**May-2029**	$66.62	$44.52	$57.35
Jun-2024	$60.42	$37.00	$50.01	**Jun-2029**	$60.84	$34.65	$49.78
Jul-2024	$73.85	$54.56	$65.76	**Jul-2029**	$78.50	$58.25	$69.57
Aug-2024	$81.15	$63.73	$73.85	**Aug-2029**	$87.28	$68.59	$79.44
Sep-2024	$78.43	$65.87	$72.85	**Sep-2029**	$83.39	$69.74	$77.33
Oct-2024	$76.90	$67.13	$72.80	**Oct-2029**	$82.06	$69.57	$76.82
Nov-2024	$81.21	$73.27	$77.86	**Nov-2029**	$86.91	$76.75	$82.62
Dec-2024	$76.16	$71.06	$73.91	**Dec-2029**	$81.54	$75.06	$78.69