Appendix D: Electricity Price Forecast Preliminary Draft

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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 mean value electricity market price for the Council's portfolio risk model and is used for the ProCost model used 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 AURORA$^{xmp®}$ Electric Market Model[1] to forecast wholesale power prices. AURORA$^{xmp®}$ 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, once updated and otherwise set up for the forecast, is also used to support the analysis of issues related to power system composition and operation, such as the effectiveness of greenhouse gas control policies.

A preliminary forecast is prepared early in the development of the power plan to guide resource assessments and to provide an initial basis for the demand forecast and the portfolio analysis. The preliminary forecast described in this appendix. Prior to adoption of the final plan, the

[1] The AURORA^{xmp} Electric Market Model, available from EPIS, Inc (http://www.epis.com/).

forecast will be rerun using the final fuel price forecast, assumptions regarding resources, demand forecast and portfolio recommendations.

FINDINGS

Load serving entities in the Pacific Northwest depend on the wholesale marketplace to match their customer's ever changing demand for electricity with an economical supply. The wholesale power market promotes the efficient use of the region's generating resources by assuring that the resources with the lowest operating cost are serving the demand in the region. In the long-run, the performance of the wholesale power market, and the prices determined in the marketplace, largely depend on the balance between the region's generating resources and demand for electricity. On the supply-side, there are three primary factors that are likely to influence the wholesale power market over the current planning period: (1) the future price of natural gas; (2) the future price of carbon dioxide (CO_2) allowances associated with climate control regulation; and (3) the future path of renewable resource development associated with the region's Renewable Portfolio Standards (RPS).

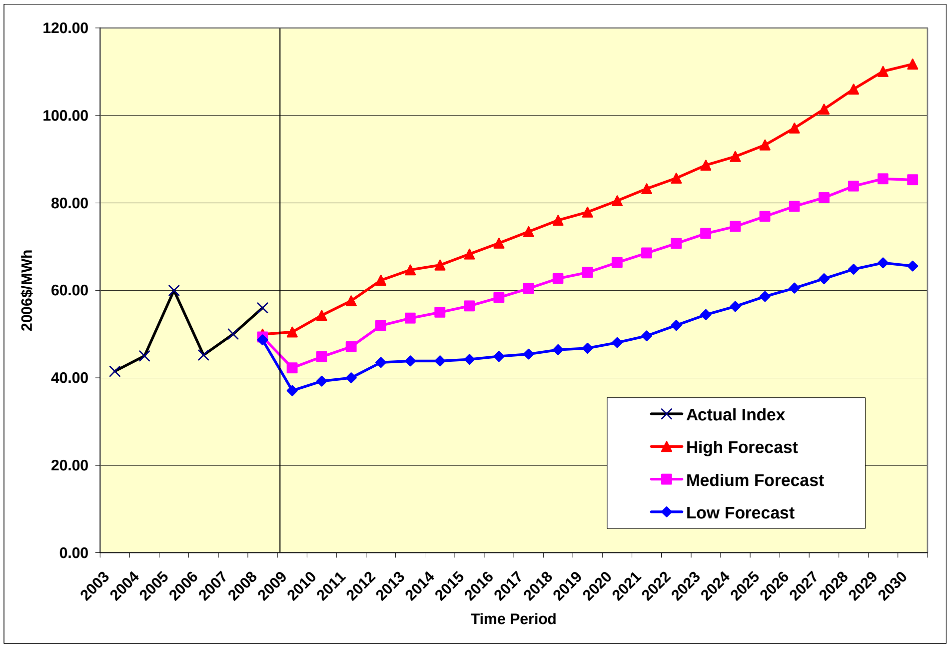
Natural gas-fired generating units are often the marginal generating unit, and determine the wholesale price of electricity during most hours of the year. The cost of natural gas fuel is the major component of the variable cost of operation for a combined-cycle plant and therefore the largest component of the marginal cost of electricity for any hour that a combined-cycle plant is on the margin. To establish a plausible range for the future long-term trend of wholesale power prices in the Pacific Northwest, the Council has forecast wholesale power prices using its low, medium, and high forecasts of fuel prices described in Appendix A.

The Council's forecast of expected CO2 allowance prices begins in 2012 at a price of $8 per short ton of CO_2 emitted, increases to $27 per ton in 2020, and to $47 per ton in 2030. Uncertainties regarding future climate control regulation and its impact on future resource development in the region are discussed more fully in Chapter 10.

Three of the four Northwest states (Montana, Oregon and Washington) have enacted renewable portfolio standards. There has been a rapid pace of renewable resource development in Pacific Northwest in recent years and the region's utilities appear to be well positioned to meet their RPS targets. The Council has forecast an expected build-out of renewable resources associated with state RPS and British Columbia energy policy in the western U.S. as a whole. By 2030, the cumulative capacity of the RPS build-out includes: 17,000 MW from wind plants; 4,000 MW from concentrating solar plants; 3,000 MW from solar photovoltaic plants; and roughly 1,000 MW each from geothermal, biomass, and small hydro plants.

Under "medium" fuel price and carbon dioxide (CO2) emission price assumptions, wholesale power prices at the Mid-Columbia trading hub are projected to increase from $45 per megawatt-hour (MWh) in 2010 to $85 per MWh in 2030. For comparison, Mid-Columbia wholesale power prices averaged $56 per MWh in 2008 (in real 2006 dollars). Figure D-1 compares the forecast range of Mid-Columbia wholesale power prices to actual prices during the 2003 through 2008 period.

Figure D-1: Forecast Range of Annual Mid-Columbia Wholesale Power Prices



The Council's wholesale power price forecasts are projections of the long-term trend of future wholesale power prices. Short-term electricity price risk, due to such factors as disequilibrium of supply and demand, and seasonal volatility due to hydro conditions are not reflected in the long-term trend forecasts. This short-term price volatility is modeled in the Regional Portfolio Model that the Council uses to inform its development of the Power Plan.

Pacific Northwest electricity prices tend to exhibit a seasonal pattern associated with spring runoff in the Columbia River Basin. The Council's forecast of monthly on-peak and off-peak wholesale power prices exhibits an average seasonal hydroelectric trend during each year of the planning period. Figure D-2 shows the medium forecast of Mid-Columbia monthly on-peak and off-peak power prices. The forecast show a narrowing of the difference between on-peak and off-peak power prices over the planning period. Table D-1 shows the forecast values for selected years.

Figure D-2: Medium Forecast of Mid-Columbia Wholesale Power Prices

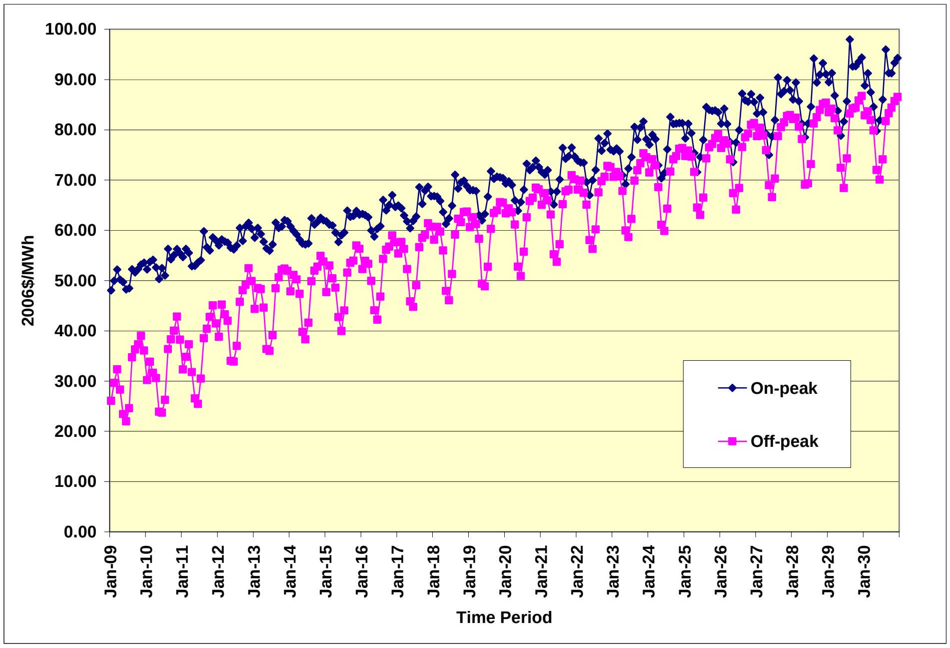


Table D-1: Forecast of Mid-Columbia Wholesale Power Prices

	On-Peak	Off-Peak	Average
Actual 2008	62.00	49.00	56.00
2010	54.00	33.00	45.00
2015	61.00	50.00	56.00
2020	70.00	62.00	66.00
2025	80.00	73.00	77.00
2030	89.00	81.00	85.00
Growth Rates			
2010-2020	2.61%	6.30%	3.93%
2020-2030	2.43%	2.62%	2.51%

The range of trend forecasts discussed here represents only one aspect of the uncertainty addressed in the Council's power plan. The low to high trend forecasts are meant to reflect current analysis and views on the likely range of future prices, but the plan's analysis also considers variations expected to occur around those trends. The plan reflects three distinct types of uncertainty in wholesale electricity prices: (1) uncertainty about long-term trends, (2) price excursions due to disequilibrium of supply and demand that may occur over a number of years, and (3) short-term and seasonal volatility due to such factors as temperatures, storms, or storage levels. These forecasts discuss only the first uncertainty. Shorter-term variations are addressed in the Council's portfolio model analysis.

APPROACH AND ASSUMPTIONS

The Council uses the AURORA$^{xmp®}$ Electric Market Model to forecast wholesale electricity prices for the Pacific Northwest.[2] The AURORA^{xmp} model projects future wholesale power market prices based on model inputs that determine the underlying supply and demand conditions in the future. Key inputs to the AURORA^{xmp} model include forecasts of future electricity demand, inventories of existing electricity generating plants, forecasts of construction costs for new electricity generating plants, and forecasts of future fuel prices for electricity generating plants. Given the forecast of future electricity demand and the set of drivers of future electricity supply, the model then uses economic logic to project future resource additions and market-clearing wholesale electricity prices.

Many of the inputs to the AURORA^{xmp} model are described in chapters or appendices of Sixth Power Plan. Chapters 2 and 3 of the Plan describe the demand forecast. Chapter 6 describes the new generating resources assumptions. This section of Appendix D describes inputs to the

The forecast is developed in a two-step process. First, using AURORA^{xmp} long-term resource optimization logic, a forecast of resource additions and retirements is developed. In the second step, the forecasted resource mix is then dispatched on an hourly basis to serve forecast loads. 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.

The Council recently updated its AURORA^{xmp} software to version 8.4.

The Council updated many of the key inputs used in the AURORA^{xmp} model for the electricity price forecast. [Recognize that the electricity price forecast does not yet incorporate draft plan resources for the PNW]

Demand Growth

To forecast future wholesale price of electricity, we need to know the regional demand for electricity as well as demand from other regions in the Western U.S., Canada and Mexico that form the WECC region. Electricity demand is analyzed not only by sector but by geographic region. The Council's AURORAxmp electricity market model requires energy and peak load forecasts for 16 areas, four of which are forecast by the Council's demand forecast model and 12 for other areas in the Western U.S., Canada, and Mexico. Council staff projected both energy and peak demand growth in nine of these 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.

[2] Available from EPIS, Inc. (www.epis.com).
[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

AURORA requires area load projections for each year to 2053, so Council staff extended the forecasts past 2017 by calculating a rolling average of most areas for the past five years. For the Arizona and New Mexico areas, the load from 2021 through 2027 was projected to grow 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).

Firm Capacity Standards

The AURORA^{xmp} model provides the capability to perform long-term system expansion studies. Each study provides a build-out of system resources that is optimized to economically supply energy to the system while maintaining a firm capacity standard. 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 parameter is a planning reserve margin target specified for each region. The second parameter is a firm capacity credit specified for each type of generating resource.

Planning Reserve Margin Targets

The Council has configured AURORA^{xmp} to simulate power plant dispatch in 16 load-resource zones that make up the WECC electric reliability area. Reserve margin targets can be specified for each load-resource zone, for an aggregation of load-resource zones called an operating pool, or for both. The Council has specified planning reserve margin targets for two operating pools: (1) the Pacific Northwest region, which has 4 load-resource zones; and (2) the California Independent System Operator (CAISO), which has 2 load-resource zones. The remaining 8 load-resource zones are given individual reserve margin targets.

For the CAISO and 8 stand-alone zones, the planning reserve margin target was set at 15 percent. For the Pacific Northwest, the Council configured AURORA^{xmp} to reflect the capacity standard of the Pacific Northwest Power Supply 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. These reserve margin targets cannot, however, be input directly into AURORA^{xmp}.

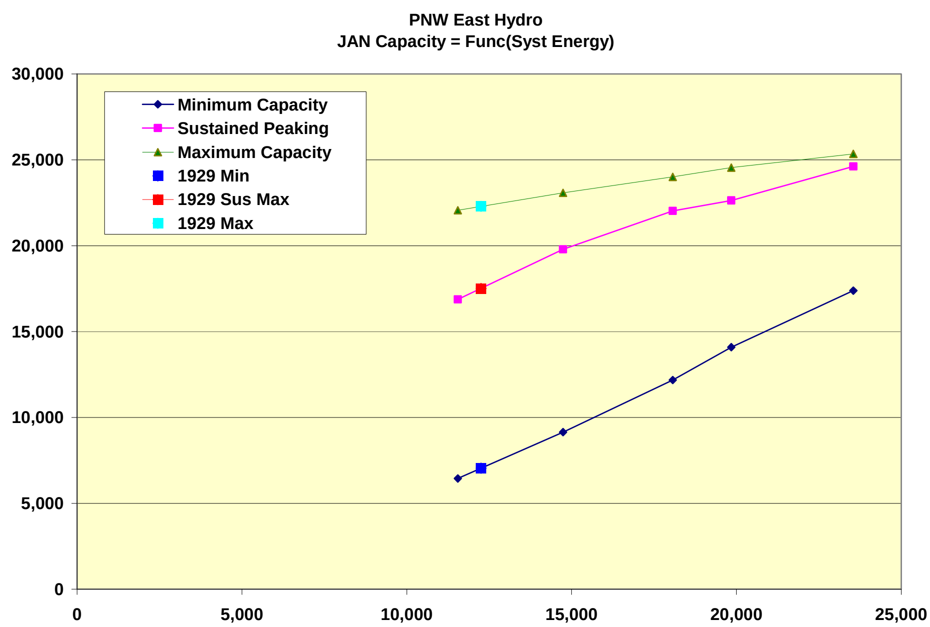
The adequacy forum targets reflect a specific set of resource and load assumptions that cannot be easily replicated in AURORA^{xmp}. For example, the adequacy forum winter reserve margin target is based on consideration of the highest average demand for a three-day 18-hour sustained peak period, while the AURORA^{xmp} targets are based on consideration of the single highest hour of demand. 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 a region's firm capacity standard is the firm capacity credit specified 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 determined by its expected forced outage rates. The Council uses a firm capacity credit for coal-fired and natural-gas fired resources in the range of 90 to 95 percent of installed capacity. For variable wind and solar resources, the Council has estimated the expected output at the time of peak demand. The Council uses a firm capacity credit of 5 percent for wind resources adopted by the Reliability Forum, and an provisional value of 30 percent for solar 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 other load resource areas.

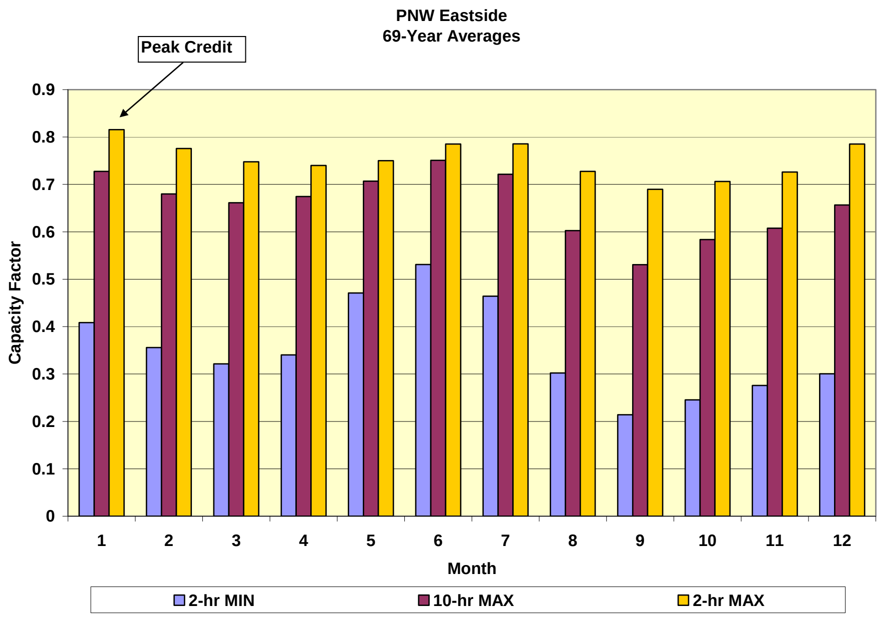
The firm capacity credits for Pacific Northwest hydro resources are based on sustained peaking studies conducted for the Pacific Northwest Power Supply Adequacy Forum. Figure D-3 shows the January peaking capability of Pacific Northwest east-side hydro resources as a function of monthly energy output. On the horizontal axis, the average monthly energy output of these hydro resources can be seen to range from 11,000 to 24,000 average megawatts. 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 (or stream flow conditions). For example, given 1929 modified streamflows and a monthly energy output of 12,000 MWa, the east-side hydro resources would be expected to provide roughly 22,000 MW of firm capacity over a two-hour peak period.

Fig D-3: PNW East Hydro
JAN Capacity = Func(Sy at Energy)



The Council has calculated the two-hour sustained firm capacity credit for both east-side and west-side hydro resources by month for each of the 69 calendar years in the Pacific Northwest streamflow record. Figure D-4 shows the two-hour firm capacity credit for east-side hydro resources by month. For hydro modeling in AURORA^{xmp}, the Council uses the January values of 82 percent of installed capacity for east-side hydro resources and 83 percent for west-side hydro resources.

Figure D-4: PNW Eastside Hydropower, 69-Year Average



Existing Resources

[Portions of this section are yet to be completed]

New Resource Options

[Portions of this section are yet to be completed]

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 located in three load-resource zones: Pacific Northwest Eastside; Pacific Northwest Westside; and Idaho South . Figure D-5, 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-5: Annual capacity factor of Pacific Northwest Eastside hydropower resources

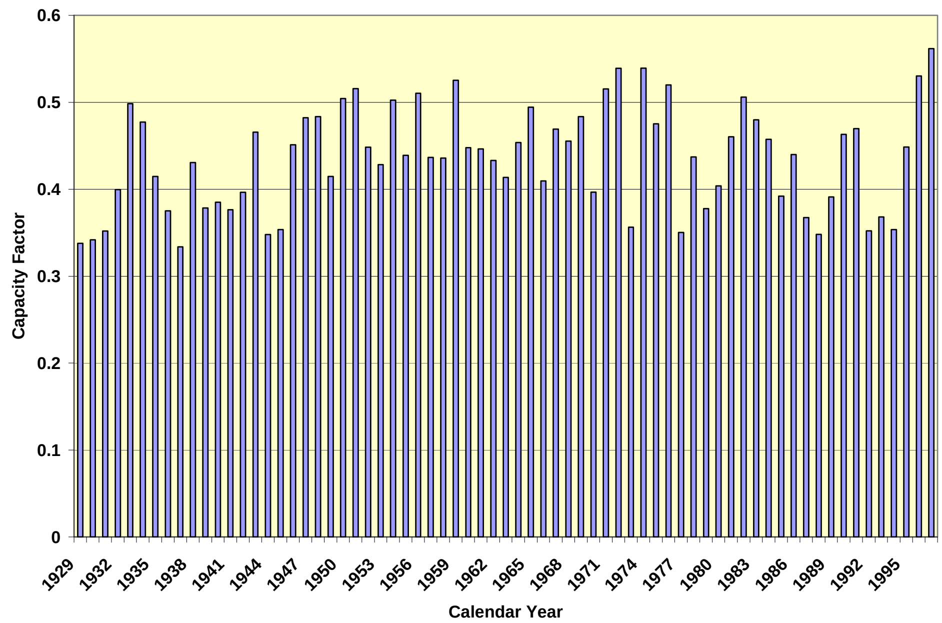
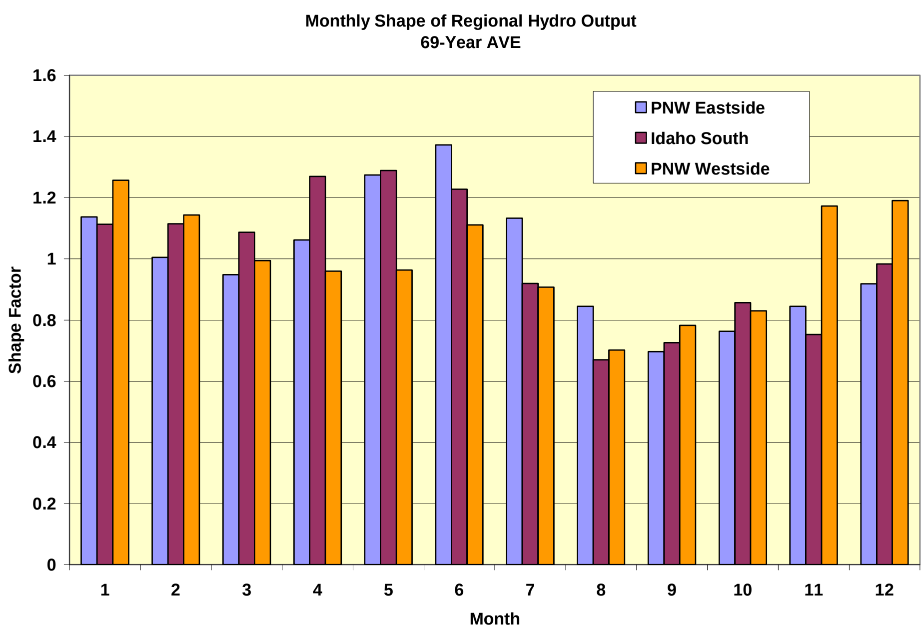


Figure D-6: Monthly Shape of Regional Hydro Output, 69 Year Avg.



State Renewable Portfolio Standards

Renewable resource portfolio standards targeting the development of certain types and amounts of resources have been adopted by eight states within the WECC; four (Colorado, Oregon, Montana, and Washington) since adoption of the Fifth Power Plan. In addition, British Columbia has adopted an energy plan with conservation and renewable energy goals equivalent to an aggressive RPS. The key characteristics of the state renewable portfolio standards and the B.C. Energy Plan are summarized in Table 3.

As discussed later in this paper, forced development of low variable-cost renewable resources can have potentially significant effects on wholesale power prices. Thus, assumptions must be made regarding the types of renewable resources that will be developed and the success in achieving the targets. For the Fifth Power Plan power price forecast, states that had enacted renewable portfolio standards were assumed to meet 75 percent of their target levels of renewable resource development.[5] Additional resources corresponding to the estimated levels of development from the Oregon and Montana system benefit charge programs were also included. Because of much greater public concern regarding greenhouse gas control, expanded initiatives for renewable resource development, prospects for even more aggressive RPS in some states, and indications that utilities will be able to achieve the initial target levels of development in many RPS states, 100 percent achievement of RPS targets was assumed for the base case of this forecast. Furthermore, because of the potentially significant effect of RPS acquisitions on wholesale prices, a more thorough assessment of the expected resource development effects of the various state RPS efforts was undertaken for this forecast.

Fuel Prices

The Council forecasts the cost of coal delivered to each load-resource zone defined in its electricity market model. The delivered coal cost is the sum of the mine-mouth price of Powder River Basin (PRB) coal, plus the variable cost of transporting PRB coal to each load-resource zone. The Council issued its current forecast of PRB coal prices on September 11, 2007. The variable costs of transportation are based on average transportation rates for PRB coal and average shipment distances from Wyoming to each load-resource zone.

Natural gas prices from the Council's recently revised fuel price forecast are used for this power price forecast. With the exception of Idaho and Montana, the assumptions used to convert natural gas commodity prices into delivered load-resource area prices for AURORA^{xmp} are those used for the Fifth Power Plan. The approaches used to estimate Idaho and Montana natural gas prices were revised to better reflect the factors controlling gas prices in those two states.

Carbon Dioxide Emission Prices

A number of industrialized nations are taking action to limit the production of carbon dioxide and other greenhouse gasses. Within the United States, a number of states, including Washington and Oregon, have initiated efforts to control carbon dioxide production. It appears that the Region could see control policy enacted at the federal, West-wide, or state level.

It is unlikely that reduction in carbon dioxide production can be achieved without cost. Consequently, future climate control policy can be viewed as a cost risk to the power system of uncertain magnitude and timing. A cap and trade allowance system appears to have been a successful approach to SO2 control and may be used again for CO_2 production control. Alternatively, a carbon tax has the benefit of simpler administration and perhaps fewer opportunities for manipulation. It is also unclear where in the carbon production chain – the source, conversion, or use – a control policy would be implemented. It is unclear what share of total carbon production the power generation sector would bear or what would be done with any

[5] States with enacted legislation at the time of the Fifth Power Plan include: Arizona, California, Nevada, and New Mexico.

revenues generated by a tax or trading system. It is unclear which ratepayer sector will pay for which portion of any costs associated with a control mechanism.

The Council's studies use a fuel carbon content tax as a proxy for the cost of CO_2 control, whatever the means of implementation. When considered as an uncertainty, studies represent carbon control policy as a penalty (dollars per ton CO_2) associated with burning natural gas, oil, and coal.

The CO_2 allowance cost values used for this forecast are described in Appendix I.

Carbon Dioxide Emission Performance Standards

As described in Chapter 10, California, Montana, Oregon and Washington have established carbon dioxide 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 lbCO2/MWh). The California standard is less restrictive, allowing production of 1100 lbCO2/MWh - a level that would allow baseload operation of many of the simple-cycle aeroderivative gas turbines installed in that state, or alternatively, require sequestration of about 50% of the CO2 production of a coal-fired plant. Although the 1100 lbCO2/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 lbCO2/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, the BC Energy Plan requires any new interconnected fossil fuel generation in the province to have zero net greenhouse gas emissions.

The BC Energy Plan requirement was approximated in AURORA^{xmp} 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.[6] The four state performance standards, in effect preclude new coal-fired plants serving utilities within the four states (investor-owned utilities only in Montana), unless the facility can be provided with carbon separation and sequestration for 40 to 50 percent of the uncontrolled carbon dioxide production of the plant. The state performance standards are difficult to simulate because contractual paths are not modeled in AURORA^{xmp}. 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 conventional coal was precluded in Idaho because of the current 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.

[6] Because the cost and performance estimates for the technology have not yet been developed by Council staff, new combined-cycle units available to the B.C. load-resource area did not include CO_2 separation and sequestration.

Initial runs showed some new economically driven coal resource development in some load-resource areas not subject to performance standards. However, subsequent runs incorporating the revised carbon allowance cost forecast showed no new coal development within the entire WECC area. Coal-fired units were subsequently removed from the available set of new resources to expedite later runs.

WHOLESALE POWER PRICE FORECASTS

The Council's forecast of Mid-Columbia trading hub electricity prices, levelized for the period 2010 through 2029, is $62.40 per megawatt-hour (in year 2006 dollars).[7] This is a 60 percent increase from the base case forecast of the Fifth Power Plan (levelized value of $38.90 per megawatt-hour). Table D-2 shows the forecast values for selected years.

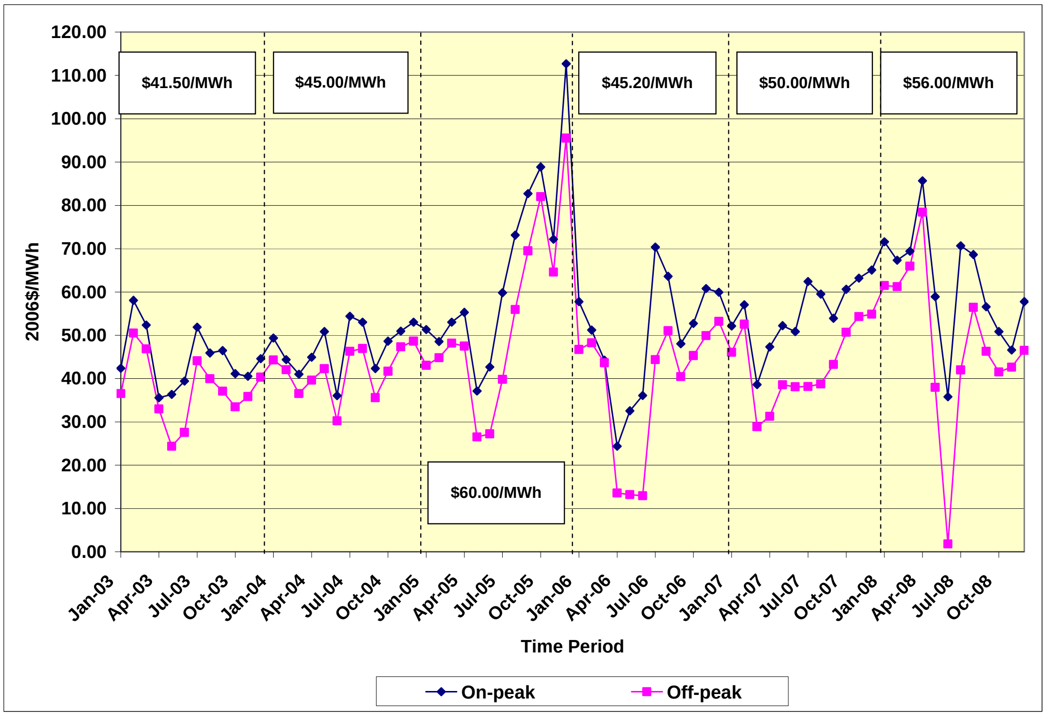
Table D-2: Forecast of Mid-Columbia Wholesale Power Prices ($2006)

	On-Peak	Off-Peak	Average
Actual 2008	62.00	49.00	56.00
2010	54.00	33.00	45.00
2015	61.00	50.00	56.00
2020	70.00	62.00	66.00
2025	80.00	73.00	77.00
2030	89.00	81.00	85.00
Growth Rates			
2010-2020	2.61%	6.30%	3.93%
2020-2030	2.43%	2.62%	2.51%

The following figure shows actual average monthly on- and off-peak prices (in $2006) at the Mid-Columbia trading for the period 2003 through 2008.

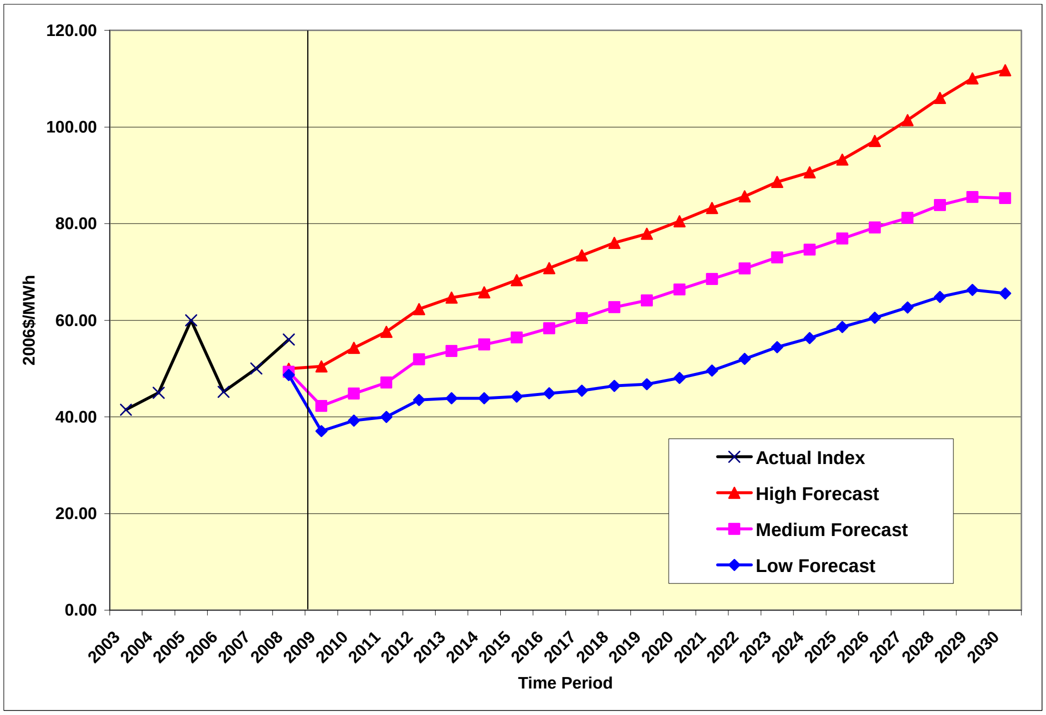
[7] All dollar values appearing in this paper are in year 2006 dollars unless otherwise indicated.

Figure-D-7: Actual 2003 -2008 Mid-Columbia Wholesale Power Prices



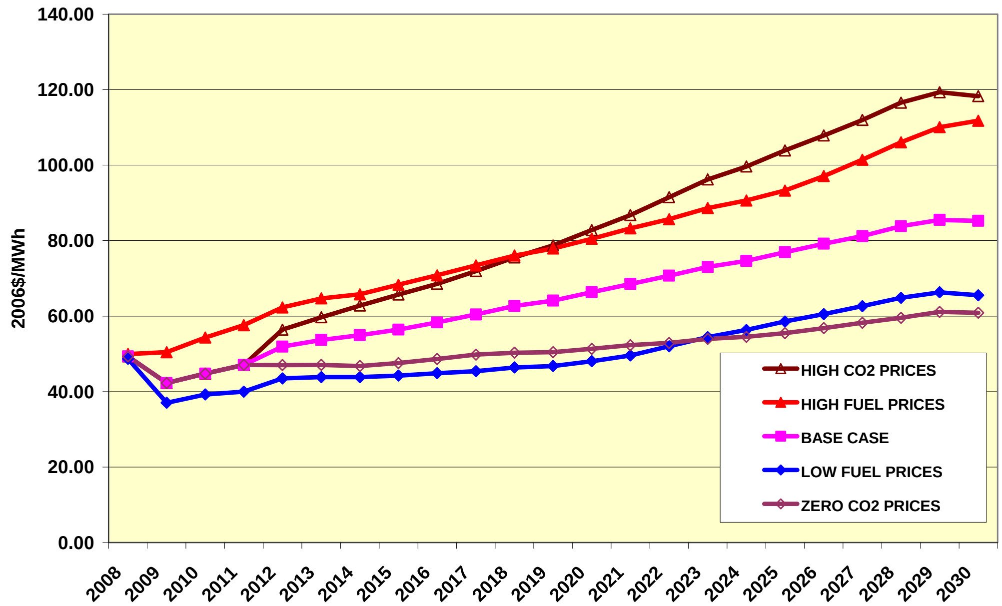
The monthly data exhibit a wide range of variation. The highest average on-peak price for the period was nearly $113 per MWh in December 2005. The lowest average on-peak price was $24 per MWh in April 2006. Annual average Mid-C prices ranged from a low of $41.50 per MWh in 2003 to a high of $60.00 per MWh in 2005.

Figure D-8: Comparison of Actual and Forecast Mid-Columbia Wholesale Power Prices



Uncertainty regarding future CO2 emissions prices and future natural gas prices could dramatically change the long-term trend forecast for wholesale power prices. We attempted to bracket the future trajectory of Mid-Columbia wholesale power prices using scenario analysis. We modeled high and low fuel price cases and high and low CO2 emissions price cases. We did not consider the potential combination of these sensitivity cases. Explain the input ranges???

Figure D-9: High and Low Mid-Columbia Wholesale Power Price Forecasts

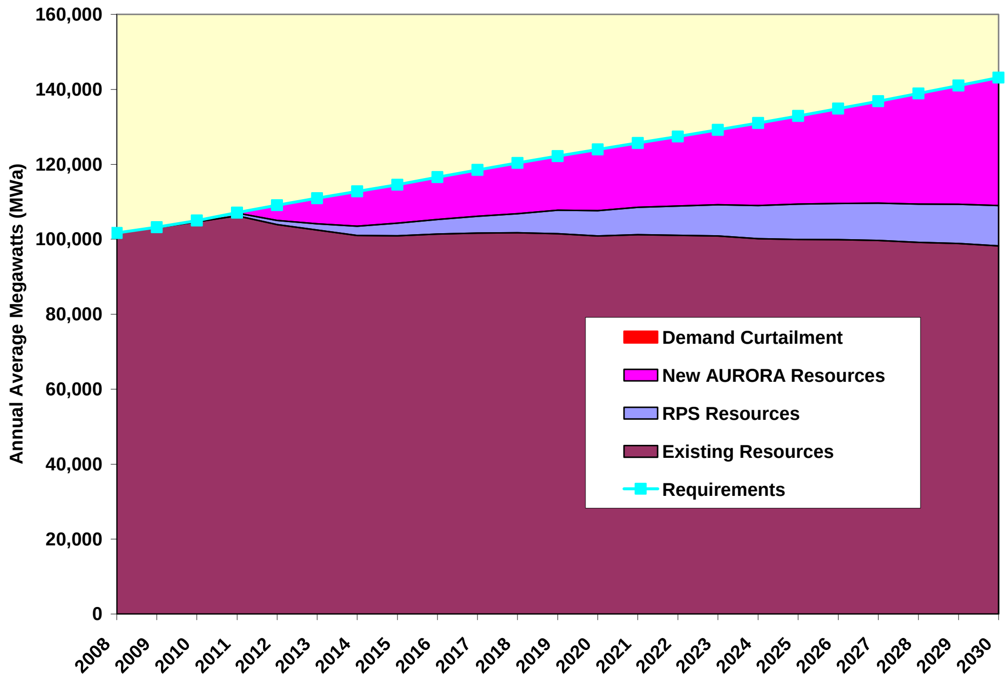


Underlying Market Fundamentals

Another way to assess the reasonableness of the wholesale power price forecast is to examine the underlying supply and demand fundamentals. Figure D-10 show the underlying annual energy load-resource balance for the Western Electricity Coordinating Council area.[8] Existing resources are shown at the bottom, "forced" RPS resource additions (discussed above) are shown as the middle wedge, and finally, modeled resource additions are shown at the top.

[8] The load-resource balance is based on the economic dispatch of the resources, not the theoretical availability the resources.

Figure D-10: WECC Annual Energy Load-Resource Balance

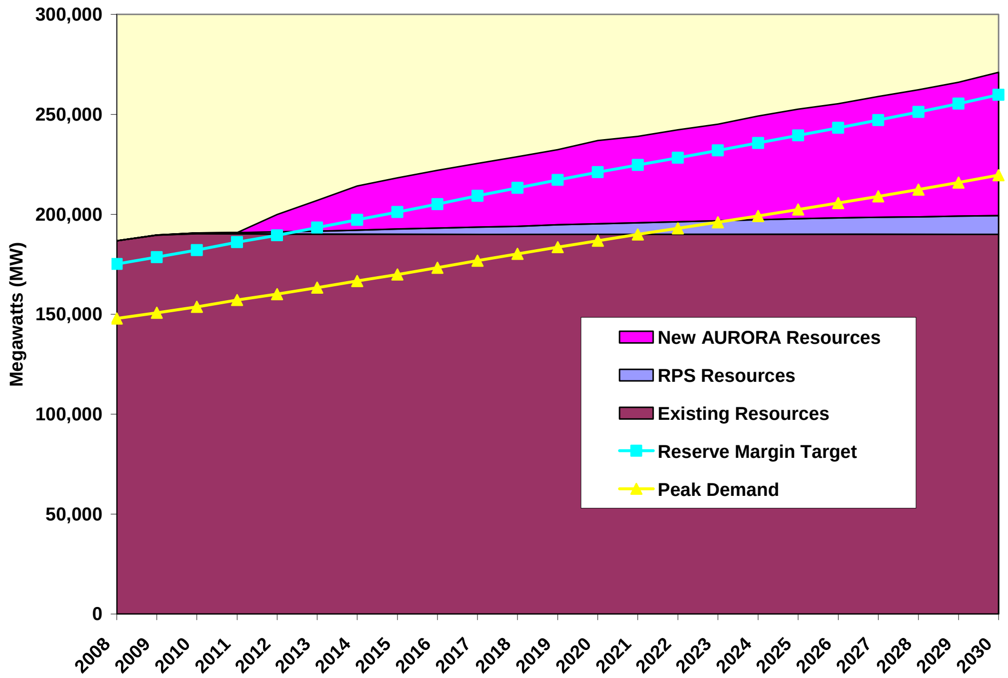


The modeled resource additions are comprised primarily of natural gas-fired combined-cycle combustion turbines. The combined-cycle turbines not only help to fill the WECC's energy deficit, but also satisfy the targeted planning reserve margins. The model's selection of resources capable of making significant contributions to meeting peak hour demand is partly due to fact that a significant part of the energy requirement is being met by "forced" RPS resources that tend to make a low contribution to meeting peak hour demand.

Figure - ??? show the underlying capacity load-resource balance by year for the Western Electricity Coordinating Council area. The figure shows the small contribution of "forced" RPS resource additions and the large contribution of "modeled" resource additions towards meeting peak hour demand.

It also shows that the model has built to a capacity surplus on a WECC wide basis. This is due to our configuration of the planning reserve margin targets. The configuration forces the model to meet planning reserve margin targets at the level of individual load-resource zones and pools. In other words, the model adds resources, in part, to fill capacity deficits at the zone and pool levels. At the WECC wide level, the sum of resource capacity contributions is greater than the need due to non-coincident hourly peaks.

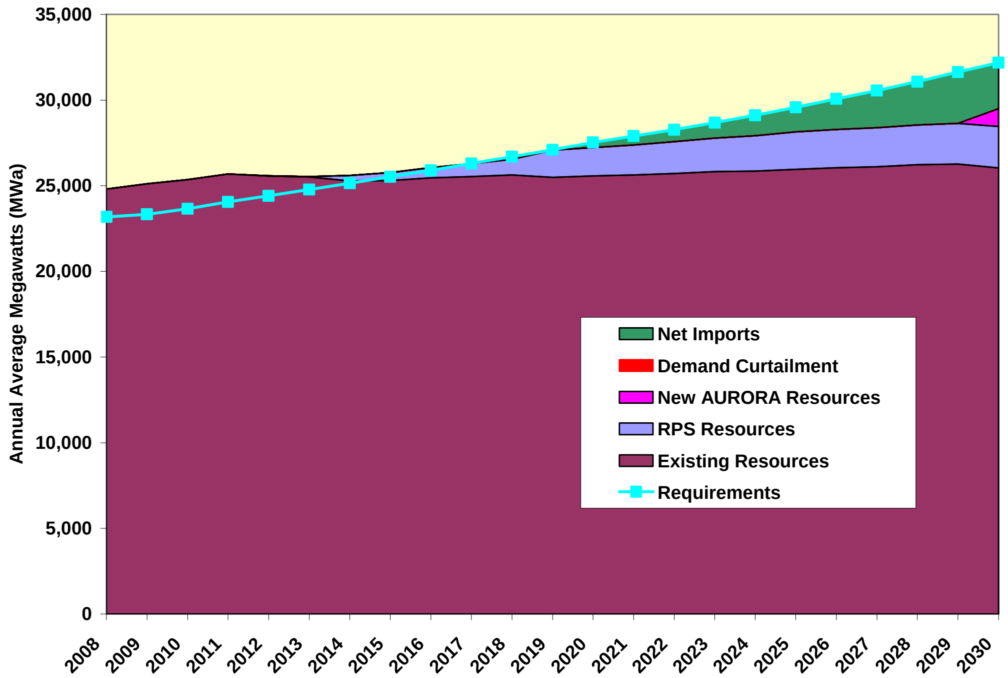
Figure D-11: WECC Annual Capacity Load-Resource Balance



The modeled addition of natural gas-fired combined-cycle combustion turbines has a significant impact on the forecasted energy load-resource balance for the Pacific Northwest. At the sub-WECC level, energy imports and exports become an important consideration. Figure - ??? shows the underlying annual energy load-resource balance for the Northwest load-resource pool.[9] Existing resources, assuming normal hydro conditions, are shown at the bottom, "forced" RPS resource additions are shown as the middle wedge, and finally, energy imports from other zones and modeled resource additions comprise the top two wedges. In the model, the region's current energy and capacity surpluses put it in the position of being able to take advantage of the excess capacity built in other areas of the WECC to meet future energy needs. This is a logical model result, it is not a recommended resource portfolio for the region.

[9] The load-resource balance is based on the economic dispatch of the resources, not the theoretical availability the resources.

Figure D-12: Pacific Northwest Annual Energy Load-Resource Balance



Forecast of Retail Electricity Prices

Typically, the price of electricity is determined through a regulatory approval process, with utilities bringing a rate proposal to their regulatory body, board of directors or city council, to seek approval of future rates. Rates are dependant on the anticipated cost of serving customers and the level of sales. Sales are determined either for a future period or for a past period. The approved rates should cover the variable *and* fixed-cost components of serving the customers.

The methodology used for forecasting future electricity prices in the Sixth Power Plan is similar to the methodology used for forecasting other fuel prices such as gas, oil, and coal. A fuel price forecast starts with a national or regional base price and then modifies the base price through the addition of delivery charges to calculate regional prices. In forecasting retail electricity prices, a similar approach is used. Starting with a forecast of the wholesale price at the Mid-C, transmission and delivery charges, plus other incremental fixed costs that are not reflected in market clearing, are added. Examples of these incremental fixed costs include the cost of conservation investments or the cost of meeting renewable portfolio standards (RPS).

Retail Rates Estimation Methodology

A three-step process was used to calculate the retail electricity prices for each state.

Step 1: For each state, the average price of electricity in 2007, measured as the average revenue per megawatt hour of sales, is calculated. The 2007 wholesale market price for Mid-C market is calculated. The difference between the average retail price of electricity and the wholesale price at Mid-C is treated as a proxy for transmission and distribution cost additions.

Note that the transmission and distribution charges calculated here (shown in the following table under the column labeled -Proxy Non-generation costs) are simply proxies for the actual transmission and distribution charges. At this point, it is assumed that these charges will stay constant in real terms over the forecast horizon.

Table D-3: Components of Retail Rate

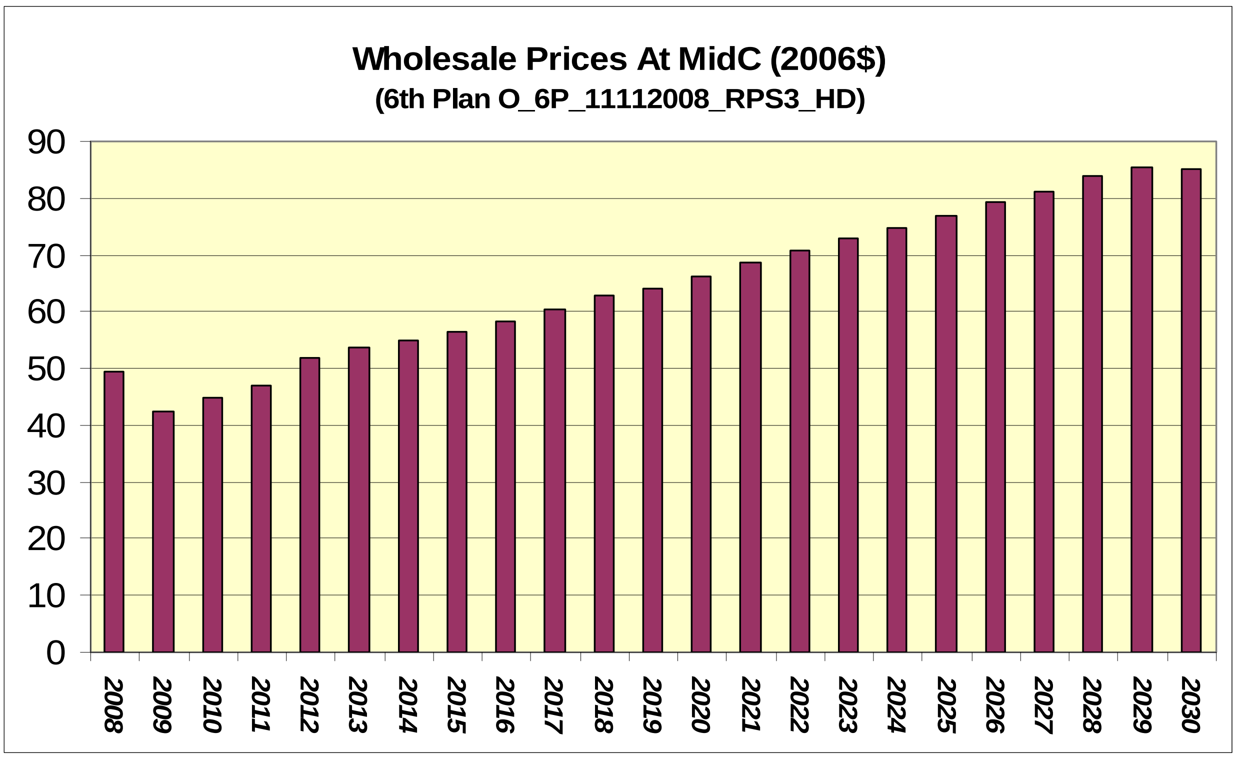
State	Average Retail Price of Electricity 2007 $/MWH	Wholesale Price Forecast for Mid C * 2007 $/MWH	Proxy Non-generation costs 2007 $/MWH
IDAHO	50.63	45.34	5.03
MONTANA	75.06	45.34	29.46
OREGON	69.96	45.34	24.36
WASHINGTON	64.12	45.34	18.52

*- based on Aurora run 6th Plan 03-13-2008 RPS HCAPTL HD

Step 2: The Interim Base Case forecast of wholesale market prices for 2008-2030, is used as the base wholesale price for electricity. The AURORA^{xmp} model produces wholesale price forecasts for many markets in the West. For the retail electricity price analysis, the Mid-C wholesale price forecast was selected as the base market hub.

The following graph shows the forecast electricity price at Mid-C for the scenario that is currently used to calculate retail electricity rates. Wholesale prices at Mid-C are projected to grow at an average annual rate of 3.3 percent for the 2010-2030 period.

Figure D-13: Wholesale Price of Electricity at Mid C



Step 3: Calculate additional costs to meet RPS standards.

RPS targets vary by state. In order to calculate additional electricity rate increases incurred by utilities for added resources to meet RPS targets, it is assumed that the costs of committed RPS resources are already reflected in the retail rates in 2007. Therefore, any additional costs would be due to the new RPS resources.

To estimate new RPS resource requirements, state or utility RPS obligations for a given year are calculated. The RPS obligation is calculated as the load forecast multiplied by the RPS target percent. If the committed RPS is above incremental RPS, no new RPS resources would be built in that year; otherwise, new RPS resources are built.

There are different resource mix options for new RPS resources that need to be built. The following table shows the Council's current assumption on how the uncommitted/new RPS resources are going to be built.

Table D-4: Assumed Market Share of New RPS Resources

	Montana	Oregon	Washington
Biomass	25.0 percent	20.0 percent	20.0 percent
Geothermal		10.0 percent	
Hydro			
Solar Photovoltaic (Load-side)		5.0 percent	5.0 percent
Solar Thermal			
Wind	75 percent	65.0 percent	75.0 percent

Each renewable generation technology has its own set of costs, including transmission and integration costs. At the moment, however, incremental transmission costs are not included in this analysis.

Interaction of RPS and Conservation: Conservation achievements reduce loads, and by reducing a utility's load, a utility's RPS target is likewise reduced. In this analysis, we calculated the rate impact of RPS with *and* without incremental conservation. Preliminary analysis indicates that, given current load forecasts and committed RPS, the region can meet RPS requirements without any new RPS resources in significant amounts until 2012.

Table D-5: Cumulative New RPS Qualifying Resources Needed (MWa)

Cumulative New RPS Qualifying Resources Needed (MWa)								
	Without Conservation			With 200 MWa /Yr Conservation target				
	MT	OR	WA		MT	OR	WA	
2008	0	0	0		0	0	0	
2009	0	0	0		0	0	0	
2010	1	0	0		0	0	0	
2011	16	0	0		15	0	0	
2012	31	0	0		30	0	0	
2013	38	23	6		37	2	0	
2014	46	34	144		44	3	108	

2015	54	48	324		52	4	272	
2016	54	59	490		52	5	419	
2017	55	180	662		52	115	568	
2018	56	515	839		53	439	720	
2019	56	583	1023		53	494	876	
2020	57	654	1214		54	551	1035	
2021	58	746	1243		54	626	1049	
2022	59	836	1272		55	698	1063	
2023	60	929	1302		55	772	1078	
2024	61	1027	1334		56	850	1095	
2025	62	1130	1368		57	931	1115	
2026	63	1164	1403		58	953	1134	
2027	64	1196	1441		58	972	1158	
2028	65	1231	1479		59	994	1182	
2029	66	1267	1518		60	1018	1206	
2030	67	1305	1559		61	1044	1232	

To calculate the effect on rates, above-market costs for RPS resources are calculated and are assumed to be recovered from target customers. For each state, using Mid-C market prices from step 1 and the levelized total cost of renewable generation technologies, total above-market costs are calculated and recovered from qualified ratepayers. For Montana, the above-market costs are recovered from Northwest customers. For the state of Washington, the RPS is applicable to 84 percent of state load, and must be met by both public and private utilities. For the state of Oregon, three different target rates are given, and the above-market costs are recovered from these target customers.

The following table shows the average rate impact of RPS with and without conservation targets. The average rate increase from RPS for the 2010-2030 period is about 1$/MWh for Montana, $3 dollars/MWH for Oregon, and about $2 per MWH for Washington, averaged over a 20-year period. On an annual basis, incremental cost increases are higher, as shown in the following table. The average rate increase for consumers in these states is similar regardless of whether or not conservation was achieved. Conservation targets lower the growth of new load but they do not significantly lower the RPS requirements.

Table D-6: Rate Impact from meeting RPS (2006 $/MWH)

	Without Conservation			With Conservation		
	MT	**OR**	**WA**	**MT**	**OR**	**WA**
2008	0.00	0.00	0.00	-	-	-
2009	0.00	0.00	0.00	-	-	-
2010	0.02	0.00	0.00	0.01	-	-
2011	0.50	0.00	0.00	0.49	-	-
2012	0.94	0.00	0.00	0.95	-	-
2013	1.14	0.22	0.02	1.15	0.02	-
2014	1.30	0.32	0.50	1.33	0.03	0.40
2015	1.45	0.43	1.05	1.49	0.04	0.95
2020	1.41	4.46	3.13	1.46	4.19	3.01

2025	1.37	6.84	3.17	1.44	6.55	3.03
2030	1.34	7.11	3.25	1.42	6.78	3.10
Average 2010-2030	1.14	3.47	1.96	1.18	3.22	1.86

Step 4: Calculate additional costs to meet conservation targets.

The next step in the analysis includes the incremental cost of conservation programs. However, this step of the analysis cannot be completed until the conservation target levels are known. The calculation of incremental costs of meeting conservation targets will be conducted after determining the optimized conservation-acquisition targets.

Table D-7: Mid-Columbia Wholesale Power Price Forecast (2006$/MWh)

Month	On-peak	Off-peak	Flat	Month	On-peak	Off-peak	Flat
Jan-2020	69.29	63.37	66.81	Jan-2025	78.29	74.78	76.82
Feb-2020	69.74	64.37	67.45	Feb-2025	81.22	75.88	78.93
Mar-2020	69.03	63.59	66.63	Mar-2025	79.32	74.64	77.26
Apr-2020	65.95	61.13	63.91	Apr-2025	75.39	71.61	73.79
May-2020	63.91	52.75	58.99	May-2025	71.58	64.53	68.62
Jun-2020	65.58	50.90	59.38	Jun-2025	74.61	63.06	69.47
Jul-2020	68.09	55.72	62.90	Jul-2025	77.99	66.50	73.18
Aug-2020	73.24	62.56	68.53	Aug-2025	84.53	74.32	80.03
Sep-2020	71.97	65.81	69.37	Sep-2025	83.94	76.50	80.80
Oct-2020	72.56	66.46	70.00	Oct-2025	83.76	77.16	80.99
Nov-2020	73.87	68.47	71.47	Nov-2025	83.89	78.35	81.43
Dec-2020	72.56	68.15	70.71	Dec-2025	83.49	79.10	81.65
Jan-2021	71.61	65.06	68.72	Jan-2026	81.22	76.36	79.18
Feb-2021	71.08	67.38	69.50	Feb-2026	84.22	77.91	81.51
Mar-2021	71.98	65.96	69.45	Mar-2026	81.16	77.24	79.43
Apr-2021	67.72	63.15	65.79	Apr-2026	77.56	74.09	76.09
May-2021	65.14	55.20	60.76	May-2026	73.56	67.40	70.84
Jun-2021	67.71	53.73	61.81	Jun-2026	77.47	64.08	71.82
Jul-2021	70.11	57.21	64.70	Jul-2026	79.95	68.42	75.12
Aug-2021	76.41	65.21	71.47	Aug-2026	87.19	76.57	82.51
Sep-2021	74.25	67.76	71.51	Sep-2026	85.88	78.50	82.76
Oct-2021	74.74	68.06	71.79	Oct-2026	85.56	79.27	82.92
Nov-2021	76.45	70.95	74.13	Nov-2026	87.09	81.00	84.38
Dec-2021	74.68	70.14	72.77	Dec-2026	85.50	81.36	83.77
Jan-2022	73.86	68.09	71.32	Jan-2027	83.21	78.74	81.24
Feb-2022	73.50	69.87	71.95	Feb-2027	86.38	80.37	83.80
Mar-2022	73.43	67.47	70.93	Mar-2027	83.48	78.87	81.55
Apr-2022	69.58	65.11	67.69	Apr-2027	79.27	75.92	77.85
May-2022	67.00	58.04	63.05	May-2027	75.01	68.99	72.36
Jun-2022	69.99	56.30	64.21	Jun-2027	78.66	66.60	73.57
Jul-2022	72.02	60.18	66.80	Jul-2027	81.93	70.29	77.05
Aug-2022	78.30	67.55	73.79	Aug-2027	90.39	78.72	85.25
Sep-2022	75.83	69.78	73.27	Sep-2027	87.11	80.53	84.33
Oct-2022	77.36	70.65	74.40	Oct-2027	87.69	81.47	84.95
Nov-2022	79.25	72.81	76.53	Nov-2027	89.89	82.74	86.87
Dec-2022	76.07	72.58	74.61	Dec-2027	87.87	82.93	85.80
Jan-2023	75.72	70.65	73.48	Jan-2028	86.03	82.14	84.32
Feb-2023	76.31	71.61	74.30	Feb-2028	89.39	82.41	86.42
Mar-2023	75.69	70.73	73.61	Mar-2028	85.66	80.62	83.55
Apr-2023	70.93	67.82	69.55	Apr-2028	81.21	78.15	79.85
May-2023	69.19	59.97	65.33	May-2028	78.52	69.08	74.56
Jun-2023	72.30	58.64	66.53	Jun-2028	81.25	69.36	76.23
Jul-2023	74.57	62.26	69.14	Jul-2028	84.61	73.17	79.57
Aug-2023	80.57	69.87	76.08	Aug-2028	94.19	81.25	88.77
Sep-2023	78.02	71.94	75.46	Sep-2028	89.41	82.47	86.48
Oct-2023	80.44	73.35	77.31	Oct-2028	90.97	83.94	87.87
Nov-2023	81.65	75.34	78.99	Nov-2028	93.25	85.14	89.83
Dec-2023	78.12	74.53	76.54	Dec-2028	91.05	85.40	88.56
Jan-2024	77.04	71.51	74.72	Jan-2029	89.45	83.48	86.95
Feb-2024	79.01	74.13	76.93	Feb-2029	91.30	84.18	88.25
Mar-2024	78.11	72.95	75.84	Mar-2029	86.84	82.27	84.92
Apr-2024	72.93	68.59	71.10	Apr-2029	83.79	79.88	82.05
May-2024	70.34	61.06	66.45	May-2029	78.83	72.44	76.15
Jun-2024	71.41	59.86	66.28	Jun-2029	81.63	68.41	76.05
Jul-2024	76.12	64.29	71.16	Jul-2029	85.66	74.30	80.65
Aug-2024	82.55	71.66	77.98	Aug-2029	97.98	83.20	91.78
Sep-2024	81.15	74.10	78.02	Sep-2029	92.58	84.24	88.87
Oct-2024	81.24	74.76	78.52	Oct-2029	92.64	84.42	89.20
Nov-2024	81.34	76.22	79.17	Nov-2029	93.54	85.82	90.28
Dec-2024	81.31	76.35	79.13	Dec-2029	94.38	86.74	91.01