Northwest Power and Conservation Council

DRAFT

Interim Wholesale Power Price Forecast

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This report describes an interim revision to the Northwest Power and Conservation Council's wholesale power price forecast. This forecast incorporates revised fuel price forecasts, estimated renewable resource acquisitions in response to state renewable portfolio standards, resource acquisitions needed to maintain target resource adequacy standards, and revised estimates of the future cost of CO_2 production. This forecast supersedes the final wholesale power price forecast of the Fifth Power Plan. This forecast will be updated as the development of the Sixth Plan progresses.

Introduction

The Northwest Power and Conservation Council forecasts regional wholesale power market prices as part of its electric power and conservation planning process. The power price forecast is a key input to the Council's portfolio risk model that is used to assess various future resource development strategies. The price forecast is also used for preliminary estimates of the cost-effectiveness of conservation and generating resources. The price forecast has also been used for planning and resource assessment by utilities and other organizations. The wholesale price forecast presented in this paper is an interim forecast primarily intended for preliminary analyses leading up to the Council's Sixth Power Plan. The forecast will be revisited as refined assessments of demand, generating resource costs, performance, and availability and other factors become available during development of the Sixth Power Plan.

The Council's interim forecast of Mid-Columbia trading hub electricity prices, levelized for the period 2007 through 2026, is $39.90 per megawatt-hour (in year 2006 dollars).[1] This is a 2.6 percent increase from the base case forecast of the Fifth Power Plan (levelized value of $38.90 per megawatt-hour). A comparison of the interim base case forecast and various sensitivity case forecasts is shown in Figure 1. Each sensitivity case varies a single model input. Sensitivity cases include: a high CO_2 cost case, high and low fuel price cases, and a 75 percent renewable portfolio standard (RPS) achievement case. A sensitivity case that eliminated incremental RPS resource development was run to illustrate the impact of RPS resource additions on wholesale power prices.

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

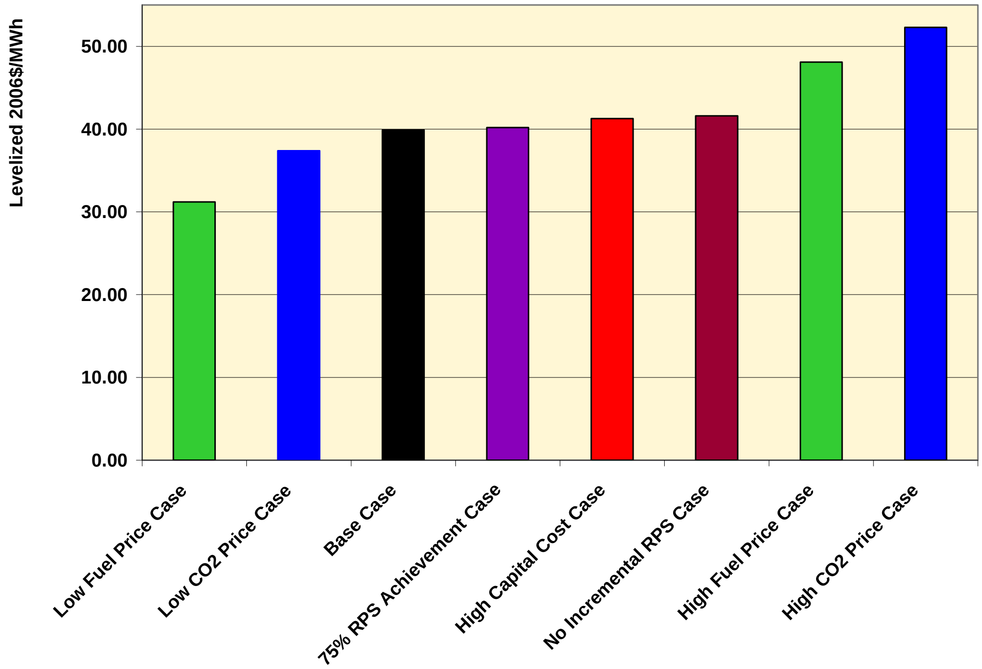

Figure 1: Interim base case and sensitivity case forecasts

An important finding of this paper is that Northwest ratepayers and utilities are likely to see, at the same time, declining wholesale power prices and rising retail rates in the near-term. This divergence between wholesale power prices and retail electricity rates is the result of the renewable portfolio standards (RPS) recently implemented in Montana, Oregon, Washington, and many other Western states.

The mandated addition of large amounts of renewable generating resources to the Western power system can be expected to dampen wholesale power prices. As a result, wholesale prices are forecast to be insufficient to cover both the construction and operating costs of new renewable resources needed to comply with RPS requirements. However, in the retail marketplace, where electricity rates are predominately cost-based, the Pacific Northwest will likely see increasing rates as the full cost of the new RPS resources, including the capital, construction, and operating costs, are included in utility rates.

Importantly, though wholesale power prices are expected to be relatively low, the Council is not recommending that regional utilities plan to rely on wholesale market purchases to meet expected load growth. A resource strategy that relies heavily on the wholesale power markets can carry significant risk. In the upcoming Sixth Power Plan, the Council will use its portfolio risk model to evaluate various resource strategies for the region, and it will adopt a final action plan for future resource development.

The divergent direction of wholesale power prices and retail electricity rates also has important implications for the conservation cost-effectiveness analysis. The direct use of the Council's forecasted power prices as "avoided costs" in conservation and generating resource assessments may no longer be appropriate for many utilities. This paper discusses a potential new avoided-cost methodology that blends forecast wholesale power prices and the full cost of RPS resource development to arrive at an overall avoided cost for utilities with RPS obligations. The Council intends to consider this issue more fully during development of the Sixth Power Plan.

Background

The Council prepares and periodically updates a 20-year forecast of wholesale electricity prices for the Pacific Northwest. 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 for the ProCost model used by the Regional Technical Forum to assess the cost-effectiveness of conservation measures. The forecasting model,[2] 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. Finally, the Council's price forecast is used by other organizations for assessing resource cost-effectiveness and for other purposes.

The Council's wholesale power price forecast was last fully updated following completion of the Fifth Power Plan resource portfolio in late 2004. That forecast used the electricity demand and fuel price forecast of the Fifth Power Plan as well as its resource costs and "mean resource development" portfolio.[3] An update of the Fifth Power Plan forecast incorporating higher near-term natural gas prices and new resource development through early 2006 was developed for the Biennial Monitoring Report of the Fifth Power Plan. Significant changes potentially affecting the price forecast have occurred since that review. These include unforeseen rapid escalation in the construction cost of many generating resources, sustained fuel prices above the medium forecast of the Fifth Power Plan, construction of substantial amounts of wind and combined-cycle capacity during a period of regional surplus of generating capacity, adoption of ambitious renewable portfolio standards by Oregon and Washington, and adoption of pilot regional energy and capacity reserve margin targets by the Resource Adequacy Forum. These changes affect future wholesale energy prices, as well as the conventional use of long-term market prices as a determinant of resource cost-effectiveness. For these reasons, it is desirable to revisit the wholesale price forecast prior to beginning work on the Sixth Power Plan.

The next update of the power price forecast will follow the development of the conservation and generating supply curves and the initial demand forecast for the Sixth Power Plan. The final Sixth Power Plan power price forecast will be prepared following development of the recommended resource portfolio.

[2] The AURORA^{xmp} Electric Market Model, available from EPIS, Inc.

[3] The resource portfolio of the Fifth Power Plan is not deterministic, but rather lays out an inventory of cost-effective resources that would be developed as needed in the future. Except for the recommendations contained in the five-year action plan, there is no single resource development schedule in the Fifth Power Plan. The mean level of resource additions, for each year and resource type observed over the 750 futures tested in the portfolio risk model, was incorporated into the AURORA model for the final price forecast of the Fifth Power Plan.

Approach and Assumptions

The Council uses the AURORA$^{xmp®}$ Electric Market Model[4] to forecast wholesale electricity energy prices for the Pacific Northwest. 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. A more detailed description of the Council's wholesale electricity price forecasting methodology is provided in Appendix C of the Fifth Power Plan.

The Council recently updated its AURORA^{xmp} software to version 8.4. As a result, this is the first time that the Council has implemented the capacity reserve margin capability of AURORA^{xmp}. The capacity reserve margin modeling is an extension of the long-term resource optimization logic and, therefore, affects the first-step of the Council's electricity price forecast process. Prior to this enhancement, the AURORA^{xmp} optimization logic iteratively added new resources and retired existing resources based on a resource's ability to cover its fully allocated going-forward costs at forecasted energy market prices. With the new enhancement, the AURORA^{xmp} optimization logic not only builds resources to meet target planning reserve margins, but also simultaneously produces estimates of the capacity prices needed to achieve or maintain the target reserve margin. The resulting forecast of resource additions and retirements now depends on the revenues derived from the capacity prices, as well as the hourly energy prices.

The Council updated many of the key inputs used in the AURORA^{xmp} model for the interim electricity price forecast. The starting point was the AURORA^{xmp} configuration used in the Council's recent CO_2 Footprint Paper. Essentially, this is the configuration described in Appendix C of the Fifth Power Plan, plus an updated inventory of existing Western Electricity Coordinating Council (WECC) area resources to include construction starts announced since adoption of the Fifth Power Plan in December 2004. This configuration was then updated to include coal and natural gas price forecasts from the Council's recent revised fuel price forecast,[5] and new resource capital costs estimates from the Council's biennial assessment of the Fifth Power Plan. The schedule of resource additions was also updated to include resources needed to fully meet state renewable portfolio standard requirements. Finally, the model's financial inputs were updated to account for recent price inflation and to consistently express the 20-year time profile of costs and revenues in constant 2006 dollars.

Coal Prices

The Council forecasts the variable cost of delivered coal to each load-resource zone defined in its electricity market model. The delivered coal cost is the sum of the wholesale 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

[4] Available from EPIS, Inc. (www.epis.com).
[5] Northwest Power and Conservation Council. Document 2007-14, "Revised Fuel Price Forecasts." September 2007.

variable costs of transportation are based on average transportation rates for PRB coal and average shipment distances from Wyoming to each load-resource zone.

The U.S. Energy Information Administration maintains the Coal Transportation Rate Database. The transportation rate for PRB coal shipments to electric utilities located in the Midwest census region averaged 10 mills per ton-mile for 2000-2001.[6] In order to protect the confidentiality of power producers, the average transportation rate for PRB shipments to electric utilities in the West census region was not reported. In its electricity market modeling, the Council used 9.8 mills per ton-mile as the variable transportation rate for shipping PRB coal to the load-resource zones in the West.[7]

To estimate the variable transportation cost of delivering PRB coal to each of the modeled load-resource zones in the West, the variable transportation rate is multiplied by the average rail distance between Wyoming and the load-resource zones. The Council used average rail shipment distances for shipments originating in Wyoming from the U.S. Department of Transportation and the U.S. Department of Commerce 2002 Commodity Flow Survey.[8] Coal shipments make up 98 percent of the ton-miles of rail transportation originating in Wyoming. Finally, the variable transportation cost was adjusted to reflect annual changes in the Council's forecast of diesel fuel prices.[9] The following table shows the average rail shipment distances and variable transportation costs for delivering PRB coal to Western load-resource zones.

[6] U.S. Energy Information Administration (EIA), Coal Transportation Rate Database (CTRDB), Table 2.02 Coal Field to Census Division: Average Transportation Rates, Distances, and Costs for Contract Coal Shipments to Electric Utilities, by Coal Field and Census Division, 1979, 1990, 1999, 2000, 2001.
[7] This rate reflects the 10 mill per ton-mile rate for Midwest utilities, with an adjustment to remove the fixed costs associated with rail rolling stock.
[8] U.S. Department of Transportation and U.S. Department of Commerce, 2002 Economic Census, 2002 Commodity Flow Survey, Wyoming, Issued December 2004.
[9] Annual variable transportation costs are adjusted to reflect 25 percent of the annual change in the Council's diesel fuel forecast. See the Council's "Revised Fuel Price Forecast," September 11, 2007.

Table 1: Average Shipment Distance and Base Coal Transportation Rate by Load-Resource Zone

Load-Resource Zone		Average Rail Shipment Distance from Wyoming (Miles)	Base Transportation Rate (2006$/MMBtu)
Pacific Northwest - West	PNWW	1,263	0.69
Pacific Northwest - East	PNWE	1,009	0.55
Idaho	ID	465	0.25
Montana	MT	411	0.22
California - North	CAN	1,233	0.67
California - South	CAS	1,233	0.67
Nevada - North	NVN	896	0.49
Nevada - South	NVS	896	0.49
Wyoming	WY	138	0.08
Utah	UT	259	0.14
Colorado	CO	517	0.28
Arizona	AZ	958	0.52
New Mexico	NM	762	0.42
British Columbia	BC	1,300	0.71
Alberta	AB	900	0.49

Natural Gas Prices

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.

Previously, the Idaho load-resource area price was based on the Rocky Mountain hub price adjusted for a distance-based differential representing transportation on the Williams Northwest pipeline serving southern Idaho. For the current forecast, Idaho natural gas prices are based on Sumas hub prices and the basis differential used for the Northwest west of the Cascades load-resource area. The resulting Idaho natural gas prices are therefore identical to the western Pacific Northwest gas prices. Underlying this approach is the fact that the Williams Northwest pipeline levies a constant "postage stamp" rate; hence, prices along the pipeline ought not to be sensitive to distance.[10]

Montana gas prices, like those of Idaho in earlier forecasts, were based on the Rockies trading hub plus a distance-based basis differential. Montana utility staff have indicated that pipeline capacity to Montana would require expansion to accommodate any significant increase in gas-fired generating capacity, and that that expansion would likely source Alberta gas. Hence, the

[10] Subsequent to setting up the AURORA^{xmp} model for these price forecasts, the derivation of Idaho natural gas prices was again revised to use the Rockies trading hub as a basis. Though not reflected in this forecast, this revision is unlikely to substantially affect the results reported in this paper. The new derivation of Idaho prices will be used for the development of the Sixth Power Plan.

Montana gas price in this study is based on Alberta's AECO hub prices, plus a basis differential equivalent to the basis differential used for the Pacific Northwest East (PNWE) load-resource area (PNWE gas prices are also based on the AECO hub because of the Alberta origin of the PGT pipeline serving the PNWE area). The revised natural gas prices for the Northwest load-resource areas are shown in Figure 2.

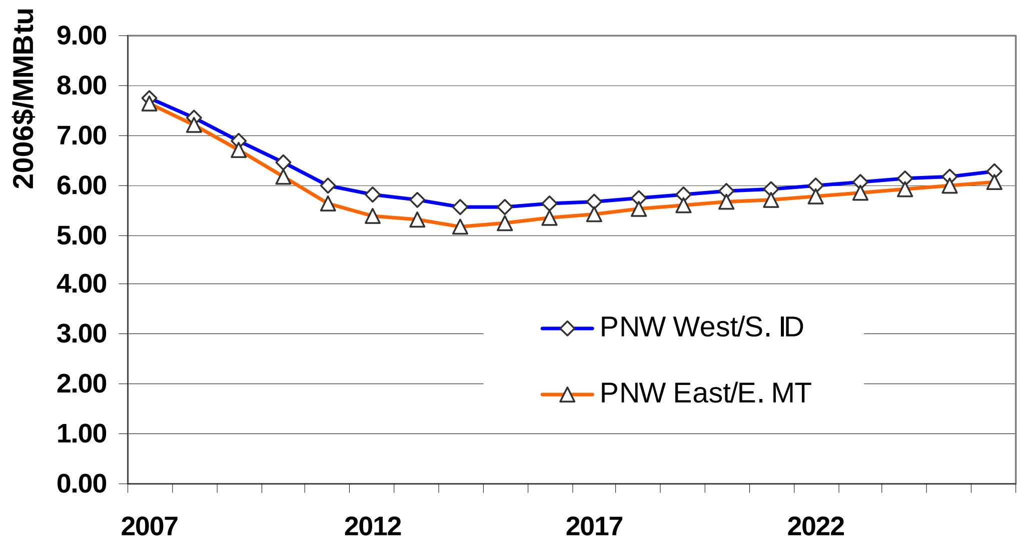

Figure 2: Delivered natural gas prices for the Pacific Northwest load-resource areas

Carbon Dioxide Emission Prices

In the Fifth Power Plan, the Council's estimates of the cost of CO_2 offsets were guided by the CO_2 offset experience of Oregon and Washington, the conclusions of a Council-sponsored workshop held in May 2003, a June 2003 MIT study of the cost of implementing the proposed McCain-Lieberman Climate Stewardship Act, and an August 2003 MIT study of the costs of CO_2 sequestration. The range of estimates of CO_2 control costs from these sources is very wide. The Oregon and Washington offset payments were about $0.87 per ton CO_2 for Oregon and $2.10 per ton CO_2 for Washington. The MIT estimates of the costs of compliance with the Climate Stewardship Act ranged from zero to $39 per ton CO_2 in 2010, $10 to $70 per ton CO_2 in 2015, and $13 to $86 per ton CO_2 in 2020. The Council workgroup estimated offset credits on the international market to range from $5 to 10 per ton CO_2 in the 2005 - 2013 timeframe, and $20 to $40 per ton CO_2 from 2010 - 2025. Finally, the MIT study on the costs of CO_2 sequestration estimated costs ranging from $2 to $23 per ton CO_2 for various forms of geologic sequestration (2000 dollars).

The Council incorporated this uncertainty into its power system planning by modeling future CO_2 emissions prices probabilistically. In the Council's portfolio risk model, future carbon emission prices were randomly selected from between zero and $15 per ton if carbon regulation was enacted between 2008 and 2016; and between zero and $30 per ton if regulation was enacted after 2016 (in 2004 dollars). This modeling produced 750 possible future trajectories of CO_2 emission prices.

In subsequent wholesale power price forecasts, the Council used the average of the 750 trajectories as its base case CO_2 emissions price forecast. Base case CO_2 emission prices gradually increased from zero dollars per ton in 2007 to $7.92 per ton in 2026 (levelized value of $3.50 per ton in 2006 dollars).

In developing the revised base case estimates of future CO_2 emission prices for this forecast, Council staff considered the range of cap and trade proposals introduced in the 110th Congress. Staff considered future adoption of the most restrictive or most lenient proposals to be unlikely. Staff identified the "safety valve" price in the Low Carbon Economy Act, put forth by Senators Bingaman and Specter, as a reasonable mid-range forecast.[11]

The Bingaman-Specter legislation would cap CO_2 emissions at 2006 levels in 2020 and at 1990 levels in 2030. These caps are less stringent than those in other proposed legislation introduced in the 110th Congress. However, unlike the other proposals, which include generic measures designed to release the CO_2 emissions cap if the cost of compliance becomes unacceptably high, the Bingaman-Specter legislation specifically identifies a cost of compliance that triggers regulatory relief. Council staff concluded that the Bingaman-Specter "safety valve" price would likely be economically sustainable over the forecast period, and therefore represent a good interim base case forecast.

In the revised base case, CO_2 emission prices jump from zero dollars per ton in 2007 to $10.35 per ton in 2012, and then gradually increase to $14.50 per ton in 2026. The levelized value of $7.80 per ton is a 123 percent increase above the previous base case value. The Fifth Power Plan average price trajectory is now used as a low CO_2 emission price sensitivity case. We also model a high CO_2 emission price case with a levelized value of $28.00 per ton. The following figure compares these three cases.

[11] The "safety valve" price (called a "technology accelerator payment" in the Act) is $12 per ton in 2012 and would increase at 5 percent above inflation annually.

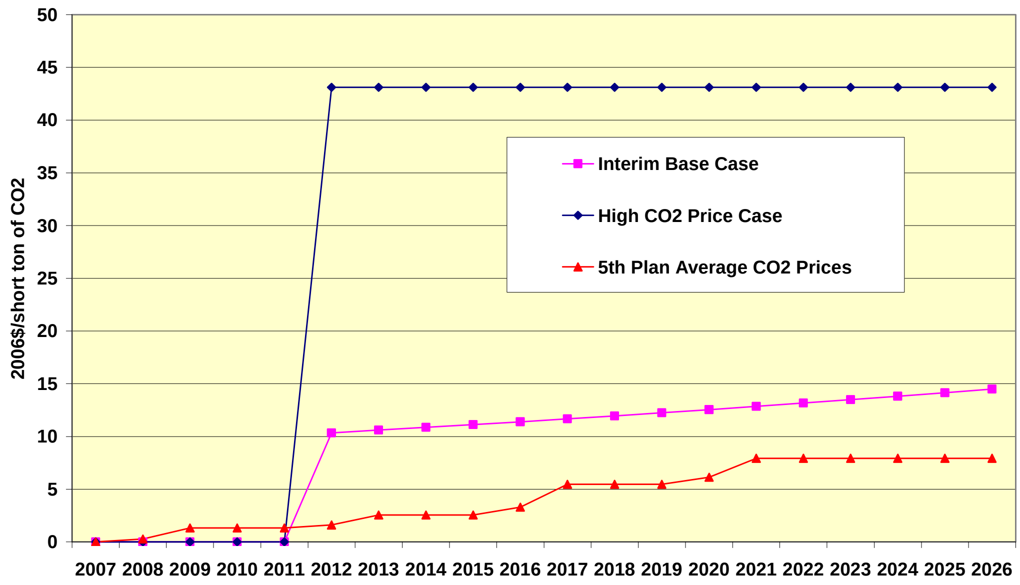

Figure 3: CO_2 emissions prices in base and sensitivity cases

The Council will further evaluate CO_2 emission prices during development of the Sixth Power Plan.

New Resource Capital Costs

The real (constant dollar) capital costs of most new generating resource technologies had declined on average for many years prior to 2004. These declines were driven by factors including technology improvements, production economies, buyer's markets, and a strong dollar. Anticipating continuation of this declines, the Council, in its Fifth Power Plan for most generating resources forecast continued real cost reductions based on historical rates of real cost de-escalation.

Beginning in 2004, power plant construction costs began to rise in real dollar terms. This increase was first evident in the cost of wind power development. In its 2006 Biennial Monitoring Report of the Fifth Power Plan, the Council identified a capital cost increase of 20 to 30 percent over the Fifth Power Plan base year costs for wind power. This increase was attributed to a weakening dollar, escalation in the price of commodities such as copper, steel, and cement used in power plant construction, and a shortage in skilled labor and specialized equipment for construction of wind plants resulting from strong demand. The Council concluded that the observed cost increases were likely cyclic and costs would revert to trends identified in the Fifth Power Plan unless the adoption of state resource portfolio standards continued to drive a strong seller's market in wind power. At the time, fossil fuel generation technologies appeared to be only moderately affected by escalating construction costs.

The base case of this forecast uses the resource capital costs of the biennial monitoring report. With the exception of solar photovoltaics, no real reduction in cost is assumed given the uncertainty regarding future price trends. The base year (2006) resource construction costs used in this forecast are shown in Table 2 compared to the equivalent costs of the Fifth Power Plan.

Power plant costs have continued to rise in real terms, and have now affected nearly all forms of power generation with the exception of solar photovoltaics. The cost of power from capital-intensive options such as coal-fired power generation will be more significantly affected than the cost of power from less capital-intensive generation such as natural gas combined-cycle plants. This will potentially shift future resource choice compared to that of the base case, and may increase the price forecast. For these reasons a high capital cost sensitivity analysis was run.

The high capital cost case used preliminary resource construction cost estimates for initial development of the Sixth Power Plan. High capital cost base year capital costs are compared to the base case and Fifth Power Plan assumptions in Table 2. The forecast cost trajectories for the high capital cost case are shown in Figure 4. Costs to the left of the vertical bar in the figure are based on historical values; those to the right are forecast. Costs are assumed to continue to increase in real terms until 2009, level, then decline through 2015 to equilibrium levels about 30% higher (in real terms) than 2005. Following 2015, costs resume trajectories reflecting the technology improvement rates of the Fifth Power Plan.[12]

The years shown on the horizontal axis of Figure 4 represent the vintage of the cost estimate. Construction costs are assumed to be fixed at the beginning of construction, so that the cost of a plant of given vintage will depend on the construction period. Thus, a wind project completed in 2015 is assumed to incur 2014 vintage construction costs (plus any general inflation), reflecting the one-year construction period typical of a wind project. In contrast, an IGCC plant completed in 2015 is assumed to incur 2011 construction costs because of its four-year construction period.

Table 2: Overnight base year (2006) capital cost assumptions for new resources (2006$/kW)

	Fifth Power Plan	Biennial Assessment	High Capital Cost Case
Gas turbines (aeroderivative)	$680	$680	$840
Gas turbines (frame)	$420	$420	$520
Combined-cycle	$590	$590	$730
Pulverized coal-steam	$1,450	$1,450	$1,900
Integrated gasification combined-cycle (without CS)[13]	$1,620	$1,750	$2,100
Integrated gasification combined-cycle (with 90% CS)	$2,090	$2,300	$2,700
Solar photovoltaics	$4,920	$3,288	$5,820
Wind power	$910	$1,500	$1,650

[12] An exception is the technology improvement curve for solar photovoltaics. The rate of cost reduction for solar photovoltaics is assumed to decline through time in the high capital cost case compared to the constant rate of decline assumed for Fifth Power Plan.
[13] CS: CO_2 separation and compression (excludes the capital cost of CO_2 pipeline and storage)

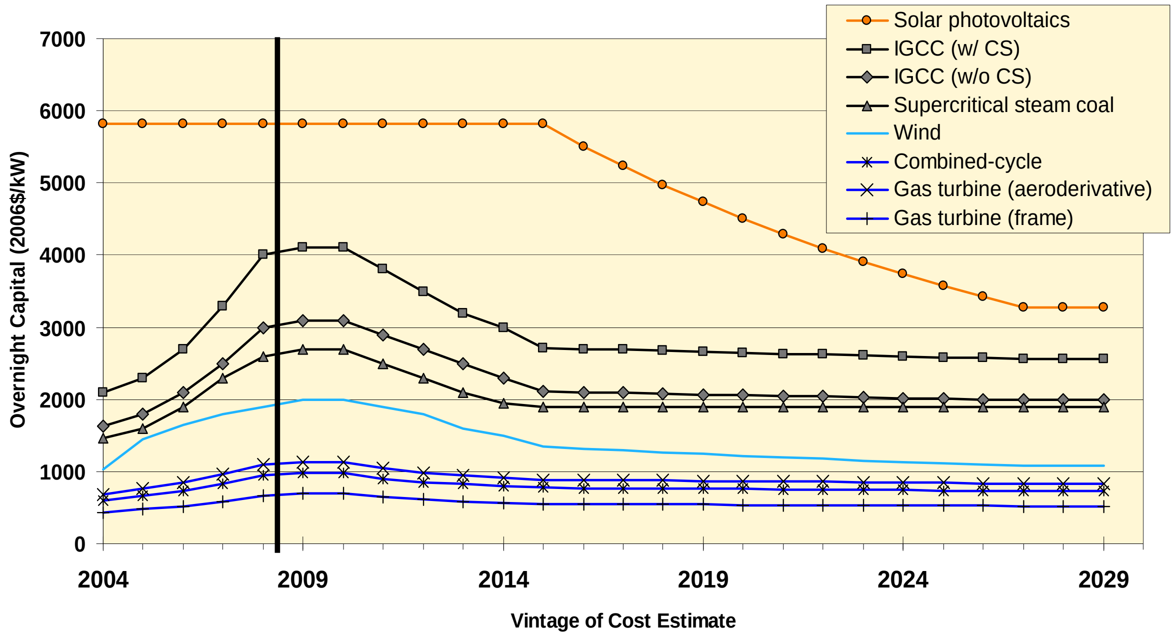

Figure 4: Historic and forecast overnight capital costs for high capital cost case (2006$)

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; three (Colorado, Oregon, 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.[14] 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.

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

Table 3 summarizes the modeling of RPS resource development by state. The right-hand column contains the estimated amount of energy from qualifying committed resources (those existing and under construction), conservation (in states where conservation is a qualifying RPS resource), and the additional resources needed to fully achieve targets in 2025. These assumptions are based on the forecast load growth rates of the Fifth Power Plan, and they assume that conservation and other resources qualifying for extra credit are developed to the fullest extent allowed, and that "off-ramp" provisions are not triggered. A sensitivity analysis assuming 75 percent achievement of RPS targets was also run.

Table 3: Renewable portfolio standard targets and resource mix assumptions

	Basic Standard	Estimated energy needed for full achievement (2025)
Arizona	15% of IOU sales by 2025	Committed 59 aMW Additional 712 aMW
British Columbia	50% of future needs by conservation 90% of all generation renewable	Conservation: 1440 aMW Committed (post-06): 101 aMW Additional: 1195 aMW
California	20% of IOU sales by end of 2010 COUs to recognize legislative intent	Committed 3670 aMW Additional 4406 aMW
Colorado	20% of IOU sales by 2020 10% by COU sales 2020	Committed 509 aMW Additional 414 aMW
Montana	15% of IOU sales by 2015	Committed 54 aMW Additional 49 aMW
New Mexico	20% by 2020 (IOUs) 10% by 2020 (Coops)	Committed 71 aMW Additional 448 aMW
Nevada	15% of IOU sales by 2015 (Up to 25% by conservation)	Conservation: 284 aMW Committed: 232 aMW Additional: 565 aMW
Oregon	25% of sales by 2025 (large utilities) 10% of sales by 2025 (medium utilities) 5% of sales by 2025 (small utilities)	Committed: 389 aMW Additional: 802 aMW
Washington	15% of sales 2020 + cost-effective conservation (utilities w/25,000 or more customers)	Conservation: Fifth Power Plan Committed: 410 aMW Additional: 989 aMW
Total		Conservation: 1,724+ aMW Committed: 5,495 aMW Additional: 9,580 aMW

<u>Windpower Supply Curve</u>

Full achievement of RPS targets was estimated to result in the development of 25,000 additional megawatts of wind by 2025. Because of the magnitude of this development, assumptions regarding the cost and amounts of wind power available for development in each load-resource area were revised using the estimates prepared by the Western Governors' Association Clean and Diversified Energy Initiative Wind Task Force[15] (WTF).

The amount of wind estimated to be available for development for each load-resource area was taken as the total from the Class 4, 5, and 6 supply curve blocks of the WTF assessment, less committed wind capacity, less the estimated wind capacity needed to support full achievement of RPS targets through the study period (assuming that the best resources are the first developed). The remaining capacity was assumed to be available for economically driven resource development. The WTF report did not include Alberta, British Columbia or Baja California. Alberta was assumed to have wind resource development potential equivalent to Montana, and BC, wind development potential equivalent to Oregon and Washington combined. Baja California was arbitrarily allocated 2,000 megawatts of Class 5 wind.

The WTF supply curve costs were scaled to the wind power cost estimate appearing in the Council's biennial monitoring report. The midpoint cost of the Class 6 supply block for Oregon (Appendix A of the WTF report) was assumed to correspond to the biennial monitoring report estimate. The midpoint costs of the WTF Class 5 and Class 4 wind power supply curve blocks for Oregon were then scaled to the revised Class 6 value. The resulting costs were then assumed to apply to the respective supply curve blocks for all load-resource areas (this simplifying assumption will be revisited).

Planning Reserve Margin

The AURORA^{xmp} model provides the capability to perform long-term system expansion studies to achieve and maintain planning reserve margin targets. The studies provide an optimized build-out of system resources and estimates of annual capacity prices needed for the marginal capacity resources to economically supply capacity to the system.

AURORA^{xmp} requires planning reserve margin targets to be based on the single highest hour of demand during the year. Reserve margin targets can be set at both the load-resource zone and operating pool level, and the optimization logic can be set to either meet or exceed the target or to minimize the deviation from the target.

The Council has configured AURORA^{xmp} to simulate power plant dispatch in 18 load-resource zones that make up the WECC electric reliability area. Planning reserve margin targets are specified for two operating pools: (1) the Pacific Northwest region , which has 6 load-resource zones; and (2) the California Independent System Operator (CAISO), which has 2 load-resource zones. The remaining 10 load-resource zones were given individual reserve margin targets. For the CAISO and 10 stand-alone zones, the planning reserve margin target was set at 15 percent. All of the planning reserve margin targets were set as minimums that are to be met or exceeded in the long-term system expansion studies.

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

[15] Western Governors' Association. Clean and Diversified Energy Initiative Wind Task Force Report. March 2006.

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 put 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 targets are 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 converted single-hour 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 adequacy standards. Both the forum's targets and the targets used in AURORA^{xmp} reflect an overall loss-of-load probability of 5 percent for the Northwest.

AURORA^{xmp} also provides the capability to set the contribution that each resource can make toward meeting the reserve margin target. The Council configured the model to limit the single-hour capacity contribution of Pacific Northwest hydro resources to 88 percent of nameplate capacity. The limit for wind and solar power resources was set at 15 and 30 percent of nameplate capacity, respectively.

CO_2 Performance Standards

The three West Coast states have established CO_2 performance standards limiting the CO_2 emissions of new baseload resources acquired by purchase or by long-term contract to 1,100 lbs. of CO_2 per megawatt-hour (approximately the CO_2 output of a very efficient natural gas fueled simple-cycle gas turbine). 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 B.C. load-resource area to integrated gasification combined-cycle (IGCC) plants with CO_2 separation and sequestration.[16] The state performance standards are more difficult to simulate because source-load paths are not explicitly 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 other 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

[16] 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.

emissions was not incorporated in this study. However, none of the runs showed new economically driven resource development in the Pacific Northwest.

Findings

Base Case

The forecast Mid-Columbia trading hub price, levelized for the period 2007 through 2026 is $39.90 per megawatt-hour. In Figure 5, the current interim base case forecast is compared to the base case forecast of the Fifth Power Plan (levelized value of $38.90 per megawatt-hour), the base case of the biennial assessment (levelized value of $38.80 per megawatt-hour), and the previous draft interim forecast (levelized value of $35.50 per megawatt-hour).

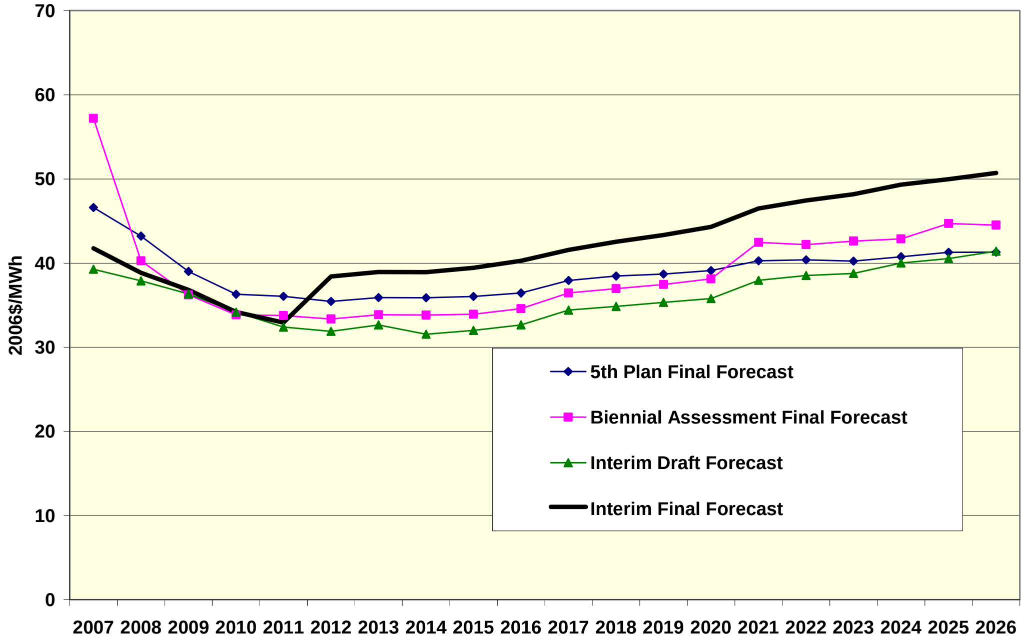

Figure 5: Interim wholesale power price forecast compared to previous forecasts

Early in the planning period, the prices of the current interim base case forecast are lower than the prices of the previous forecasts, due largely to the effect of RPS resource additions. State RPS requirements are expected to dampen future wholesale power market prices due to the addition of significant amounts of wind and other low variable-cost renewable resources to the power system.

In competitive wholesale power markets, generating resources are typically brought on-line in order of their variable operating costs. In other words, resources with low variable operating costs are dispatched before higher cost resources (with some exceptions due to operational limitations). For example, hydro generation will be brought on-line before coal-fired or natural gas-fired generation. Wind will operate regardless of price when the wind blows. The market price is determined by the operating cost of the last, or most expensive, generating unit needed to meet demand. The addition of RPS resources, with their low operating costs, will displace higher variable cost resources, primarily natural gas, and is expected to result in lower variable cost resources, such as coal, clearing the wholesale market and setting the market price during many hours of the year.

In 2012, the relative position of the current interim base case forecast switches as higher CO_2 prices drive the current forecast of wholesale power prices higher than previous forecasts. Wholesale power prices are expected to steadily increase after 2012 due to escalation of CO_2 prices and increasing natural gas prices.

The annual average prices shown in Figure 5 conceal the underlying seasonal, daily, and hourly price patterns. The monthly average prices shown in Figure 6 reveal seasonal variation due to stream flow runoff in the spring and higher, temperature-driven loads in the summer and winter.

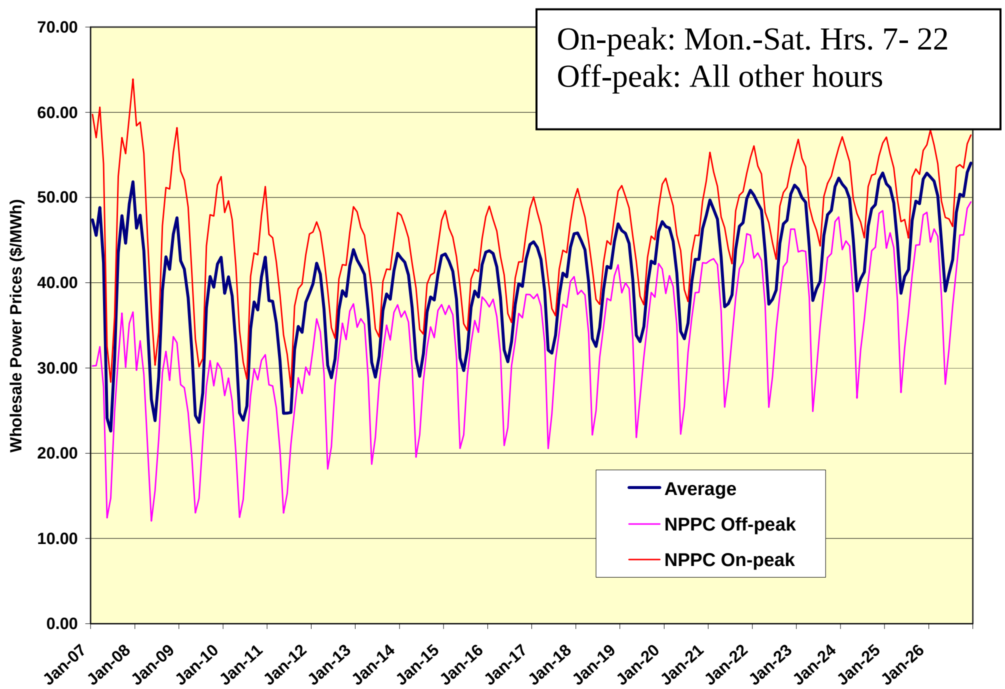

Figure 6: Forecast Mid-Columbia average monthly wholesale power prices

Wholesale power prices also vary by time of day and day of week because the marginal power plant changes with load. Gas-fired power plants with relatively high variable costs are typically on the margin during heavier load hours, whereas coal-fired plants with lower variable costs are frequently on the margin during nighttime and weekend low-load hours. The Council and the Regional Technical Forum use four load segments for assessing the cost-effectiveness of conservation measures -- many of which are most effective at specific times of day. Figure 7 shows the levelized base case price forecast for the four load segments.

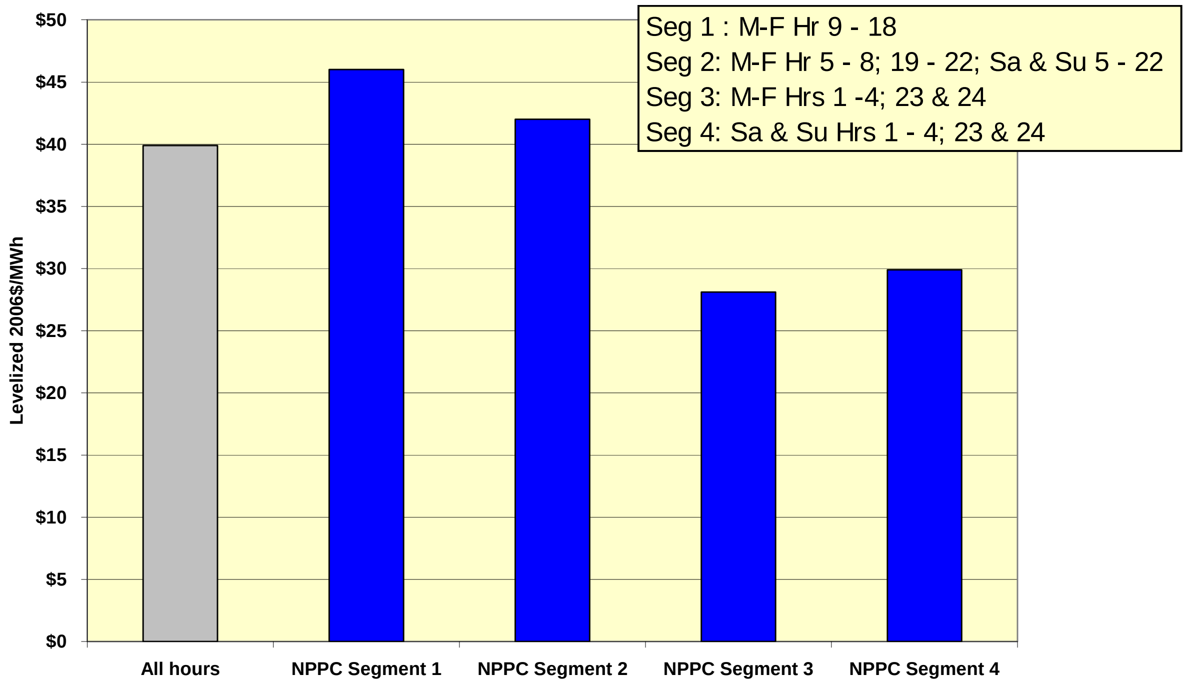

Figure 7: Forecast Mid-Columbia levelized energy prices by load segment

All of the wholesale power price forecasts presented in this paper are developed using fundamental economic drivers under "normal" or average conditions. For example, hydro electric generation is modeled using "average" stream flow conditions and retail electricity demand is based on "normal" temperatures. This type of market modeling does not adequately reflect the likely episodic price excursions that will occur due to deviations in hydro conditions and temperatures. The Council's portfolio risk model is specifically designed to account for many of the risks associated with volatile wholesale power markets. The following figure compares the "normal" 2007 power prices of the current interim forecast to actual wholesale market prices during 2004 through 2007.

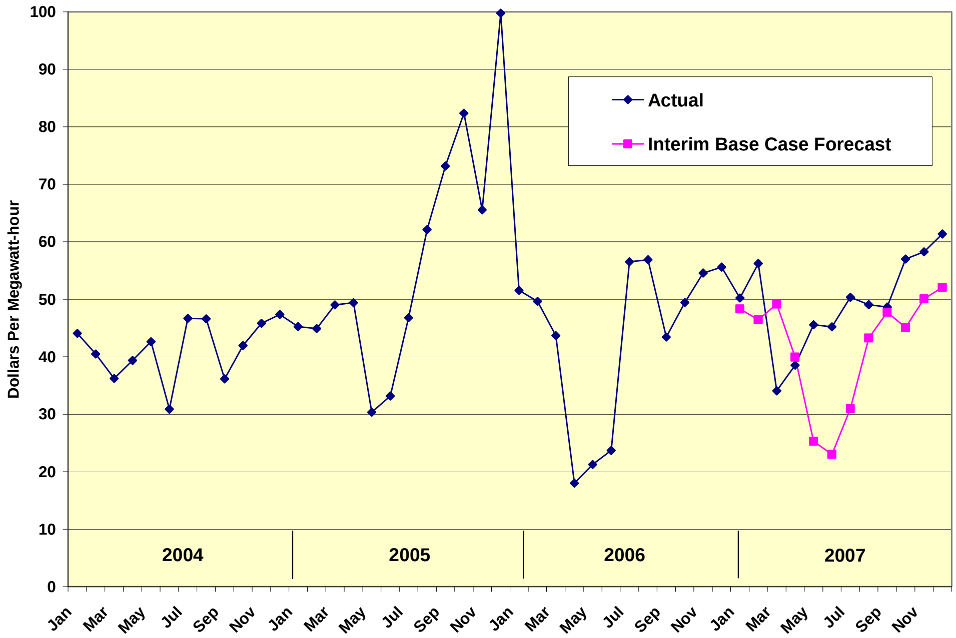

Figure 8: Comparison of forecast and actual Mid-Columbia wholesale power prices

Resource Additions and Reserve Margins

For each wholesale power price forecast presented in this paper, there is an underlying forecast of the resource mix for the WECC area. Figure 9 presents the total WECC resource mix underlying the base case power price forecast (Note that this and the following two figures show dispatched energy rather than installed capacity). Natural gas, coal, and hydro-electric generating resources account for the majority of the dispatched energy over the planning period. The amount of coal-fired generation begins to increase after 2020 as both traditional coal-fired and coal-gasification plants are added to the system to meet demand and begin to displace higher variable-cost natural gas-fired generation.

Figure 10 shows the energy output of incremental resources added to the system over the planning period. The forecast is for RPS resources and market-driven wind and natural gas-fired resources to meet WECC demand growth through 2015. After 2020, market-driven coal-fired resources provide significant amounts of energy.

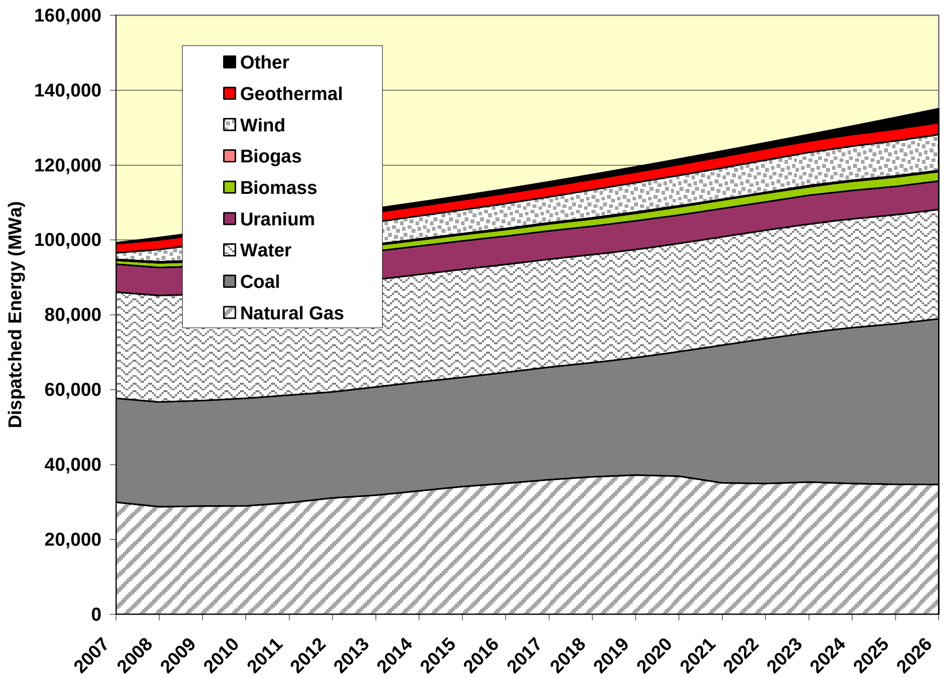

Figure 9: Forecast WECC resource mix based on dispatched energy

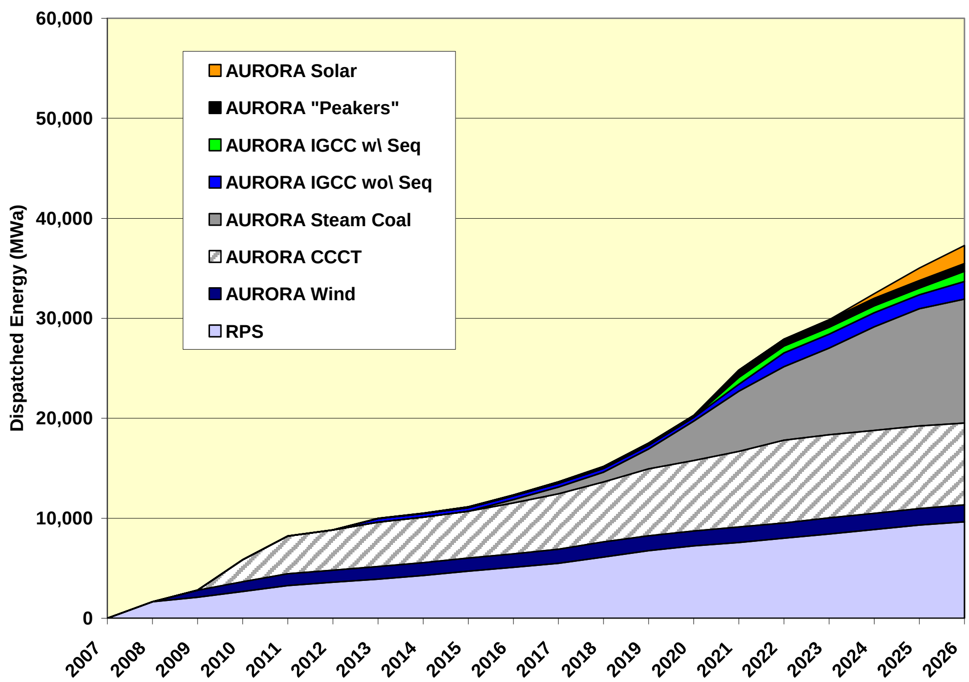

Figure 10: Forecast WECC incremental resource mix based on dispatched energy

The forecast resource mix for the Pacific Northwest reflects the dominance of hydroelectric generation and the expanding impact of wind generation (see Figure 11). By the end of the planning period, the share of energy from wind resources is expected to nearly match that of natural gas-fired resources. Under "normal" hydro conditions, the Pacific Northwest can expect to be a net exporter of energy over the entire planning period. In 2008, the region's net exports are estimated to be 3,406 annual average megawatts (MWa). With the addition of incremental RPS resources, the net exports are forecast to increase to 4,485 MWa in 2021, and then to gradually decline to 3,044 MWa in 2026, as the regional resource surplus declines and less energy is exported to other regions.

The Pacific Northwest Power Supply Adequacy Forum measures the load-resource balance of the region on the basis of resource capability and critical stream flow conditions when determining energy and economic adequacy. In 2008, the region's energy surplus on a resource capability and critical steam flow basis is estimated to be approximately 5,100 annual average megawatts. This surplus is forecast to gradually decline to approximately 4,100 annual average megawatts in 2026. Recent resource development in the Pacific Northwest, and our forecast of RPS development, appear to be sufficient to satisfy the adequacy forum's energy and economic adequacy targets over the entire planning period.

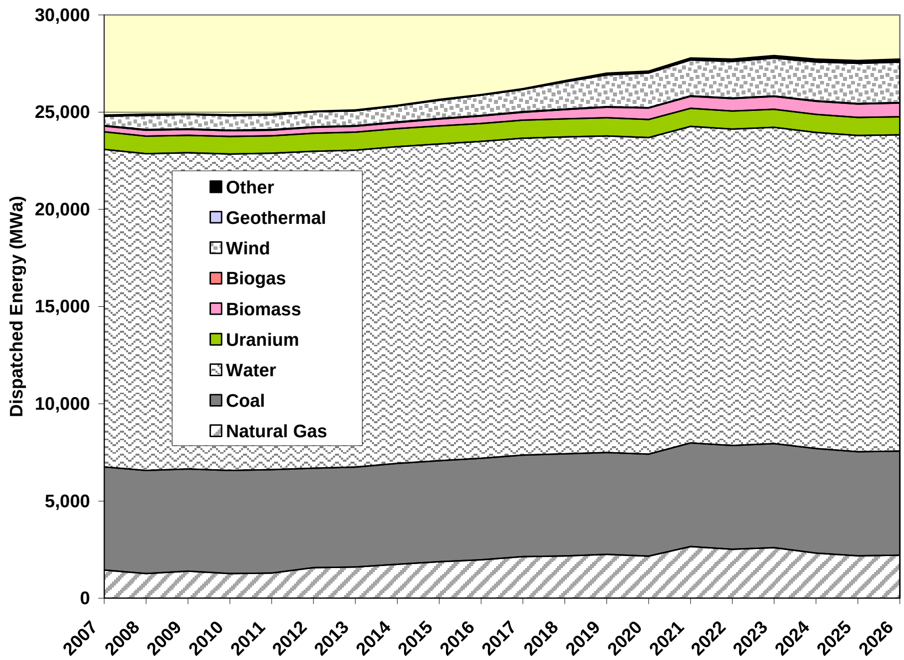

Figure 11: Forecast Northwest resource mix based on dispatched energy

Figure 12 shows the forecast of installed wind capacity in the Pacific Northwest. The region is expected to exceed 6,000 MW of installed wind capacity in 2022 (an amount consistent with the recommendations of the Fifth Power Plan).

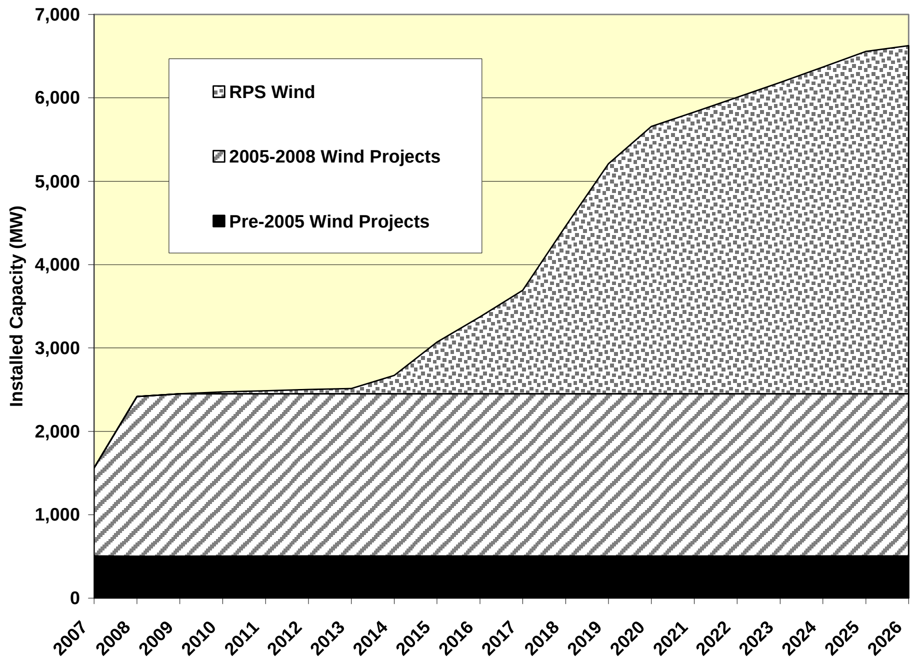

Figure 12: Forecast Northwest installed wind capacity

The following figure shows the annual peak hour reserve margin for the Pacific Northwest from the base case price forecast.

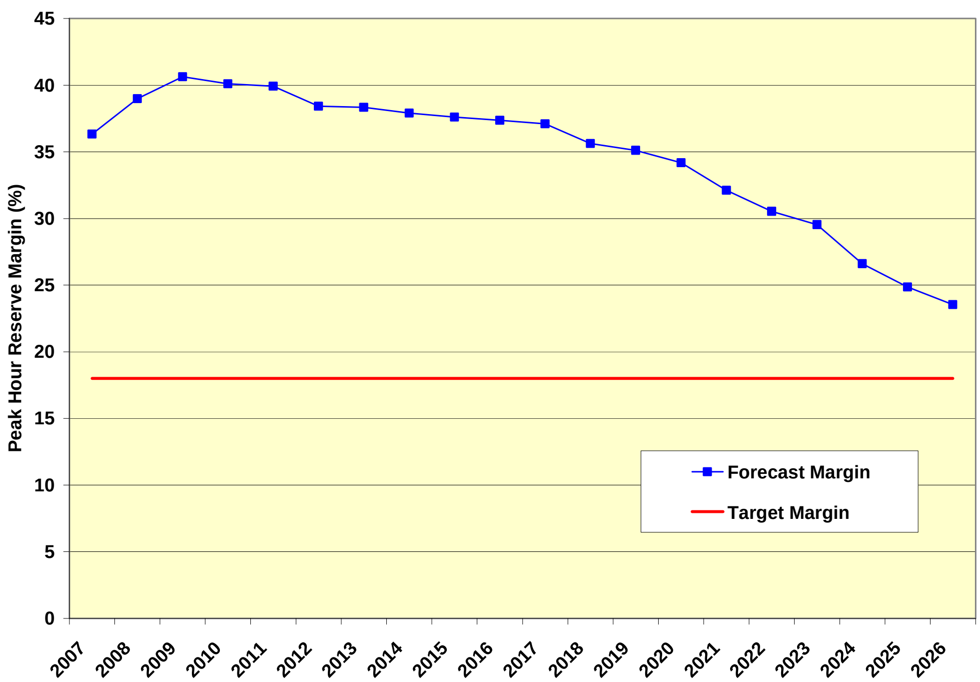

Figure 13: Forecast Pacific Northwest Annual Peak-hour Capacity Reserve Margin

The reserve margins are well above the system reliability capacity target of 18 percent over the entire the planning period. The long-term optimization logic of AURORA^{xmp} does not add any new resources in the Pacific Northwest during the planning period. This result reflects the current surplus of existing capacity in the region augmented by the forced addition of RPS resource capacity over the planning period. The Northwest Wind Integration Forum is currently investigating the capacity value of wind. A capacity value of wind below the 15 percent used in these forecasts might create a need for new resources in excess of those added to meet RPS targets.

Finally, it should be noted that AURORA^{xmp} does add 532 natural gas simple-cycle units to the WECC resource mix over the planning period. These additions add 35,555 megawatts of installed capacity. These resources are primarily added in California and other WECC areas outside the Pacific Northwest to maintain capacity reserves. These units are infrequently operated due to higher operating cost and therefore do not show prominently in Figures 8 and 9.

Sensitivity Cases

This interim wholesale power price forecast includes several alternative cases which test the sensitivity of the base forecast to changes in input assumptions. The sensitivity analysis starts with the base case assumptions and changes a single model input. Sensitivity cases include: high and low fuel price cases, a high CO_2 tax case, and a low RPS achievement case. The low RPS achievement case assumes 75 percent achievement of state RPS targets. A sensitivity case that eliminated incremental RPS resource development was run to illustrate the impact of RPS resource additions on wholesale power prices.

A comparison of the interim base case power price forecast to the sensitivity case forecasts is shown in the following figure.

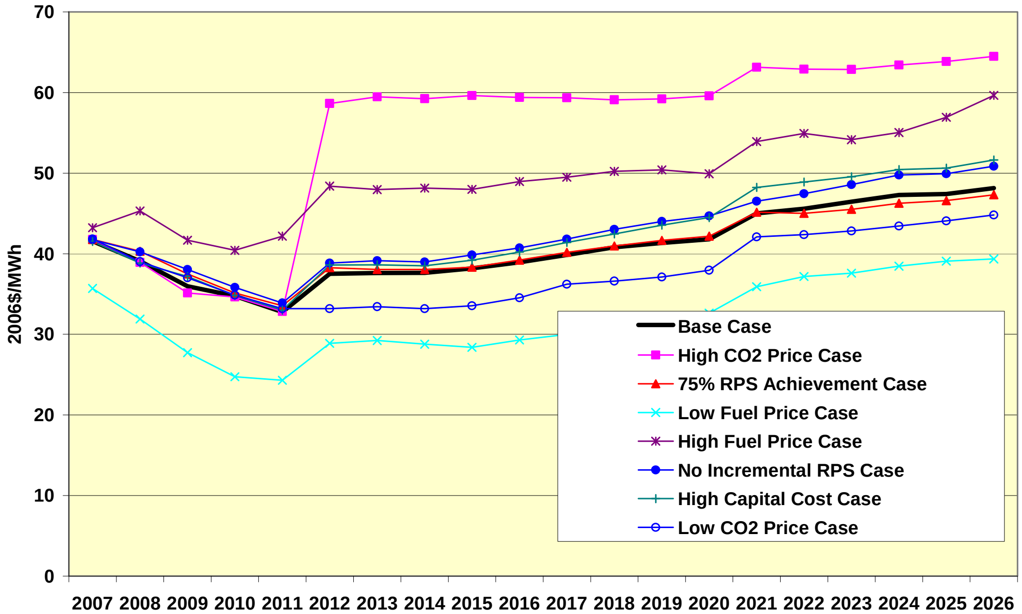

Figure 14: Interim base case and sensitivity case wholesale power price forecasts

The impact of high CO_2 prices on Mid-Columbia wholesale power prices is significant. The levelized price for the high CO_2 price case is $52.30 per megawatt-hour, 31 percent higher than the base case.

West-wide CO_2 production is only moderately affected by the revised base case CO_2 price assumptions, but significantly reduced in the high CO_2 price sensitivity case. Figure 15 compares base case and sensitivity case annual WECC-wide CO_2 production (note truncated vertical axis). Differences in CO_2 production are negligible during the period 2007 through 2011.

However, in the base case scenario, WECC CO_2 production begins to grow after 2012. The base case forecast of 511 million tons of CO_2 production from WECC resources in 2024 is 20 million tons lower than the 5th Plan Portfolio forecast from the recent CO_2 Footprint Paper. This reduction is attributable to the updated RPS modeling and the higher assumed CO_2 prices.

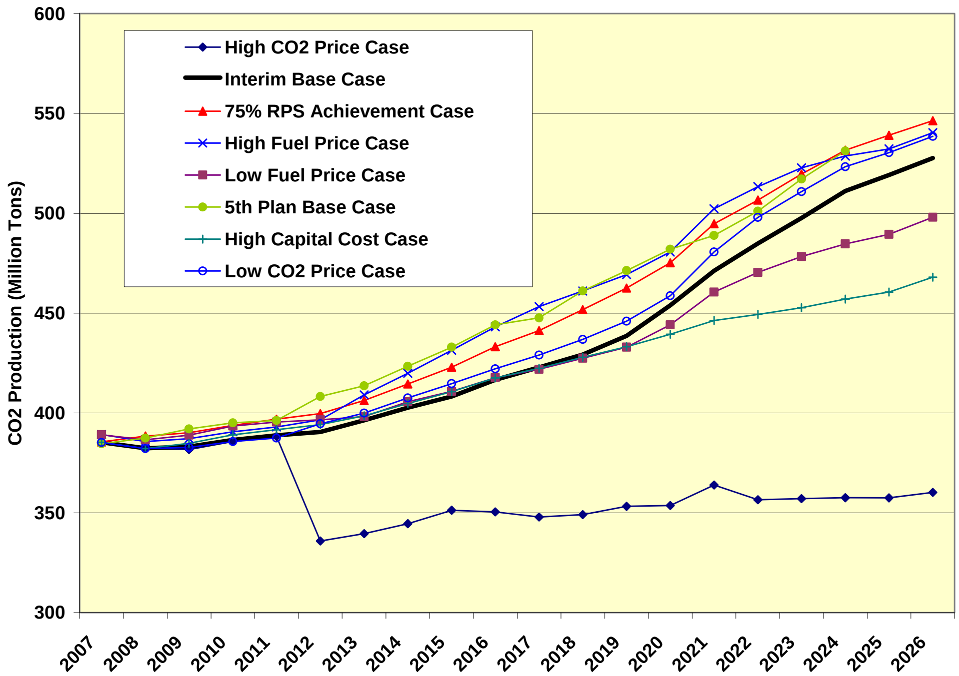

Figure 15: Interim base case and sensitivity case CO_2 production forecasts (WECC) (Note: scale of left axis begins at 300 million tons of CO_2 production)

The low CO_2 price case used the mean value CO_2 prices from the Fifth Power Plan (see Figure 3). This sensitivity case isolates the impact of the increase in base case CO_2 prices and also provides a good indication of combined impact of the other changes to the AURORA^{xmp} model since the Fifth Power Plan. The levelized wholesale power price of the low CO_2 price case is $37.40 per megawatt-hour, compared to the base case value of $39.90 per megawatt-hour. In other words, increasing the base case CO_2 price forecast raised the levelized wholesale power price forecast by $2.50 per megawatt-hour. The low CO_2 price case also had a lower levelized price than both the Fifth Power Plan forecast ($38.90 per megawatt-hour) and the Biennial Assessment forecast ($38.80 per megawatt-hour). These differences, despite higher forecast prices for natural gas and coal, can be attributed to the resource development that occurred during 2005-2007 and the development needed to achieve state RPS targets.

The seventy-five percent RPS achievement case had only a minor impact on wholesale power prices (levelized price of $40.20 per megawatt-hour). In contrast, eliminating all incremental RPS resource development raised the levelized price by $1.70 to $41.60 per megawatt-hour. The larger reduction in RPS resource development had a larger impact on wholesale power prices because it resulted in resources with higher variable operating costs setting hourly market-clearing prices.

The high fuel price case had a levelized wholesale power price of $48.10 per megawatt-hour, an $8.20 increase from the base case value. In general, higher natural gas prices result in higher wholesale power prices and more CO_2 production. The increase in CO_2 production is the result of a reduced dispatch of natural gas-fired units and an increased dispatch of traditional coal-fired units. However, whereas an increase in natural gas prices will always impact wholesale power prices (because they change the variable operating cost of the gas-fired units), a change in CO_2 production will only occur if the change in natural gas prices is large enough to result in a different resource clearing the wholesale market.

The low fuel price case had a levelized price of $31.20 per megawatt-hour, an $8.70 reduction from the base case value. Lower natural gas prices tend to lower overall CO_2 production by increasing the dispatch of gas-fired units and lowering the dispatch of coal-fired units.

In all of the Council's sensitivity cases the future resource mix of the Pacific Northwest is invariant with respect to forecast electricity prices. This is a direct result of the level of renewable resources being added to the system to meet state RPS requirements. This, combined with recent construction, appears to satisfy the region's energy and capacity needs. Additional thermal capacity may eventually be needed for integration of intermittent renewable resources.

The high capital cost case had a significant impact on the forecast mix of incremental resources added to the WECC area over the planning period (see Figure 16). Capital-intensive conventional coal-fired resources become relatively more costly and are no longer included in the incremental resource mix. Coal-gasification resources, also capital-intensive are reduced to a small increment at the end of the forecast period. Compared to the base case incremental resource mix (see Figure 10), the high capital cost case shows a 16,247 average megawatt reduction in energy from these resource types in 2026. This energy output is replaced in the high capital cost case with 5,763 average megawatts of additional output from incremental natural gas-fired resources. Though the capital cost of new natural gas resources are higher than in the base case, the increase is not as significant as for the coal resources because of the relatively small contribution of capital costs to the overall cost of power from a natural gas-fired power plant. Incremental wind and RPS resources replace 4,045 average megawatts. The remaining 6,439 average megawatts of energy in 2026 are replaced by relying more heavily on currently operating resources.

These changes in resource mix impact both wholesale power prices and CO_2 production. The high capital cost case had a levelized wholesale power price of $41.30 per megawatt-hour, a $1.40 increase over the base case value (see Figure 1). With less reliance on incremental coal-fired resources, the high capital cost case shows lower CO_2 production than the base case, however, annual CO_2 production continues to increase over the planning period (see Figure 15).

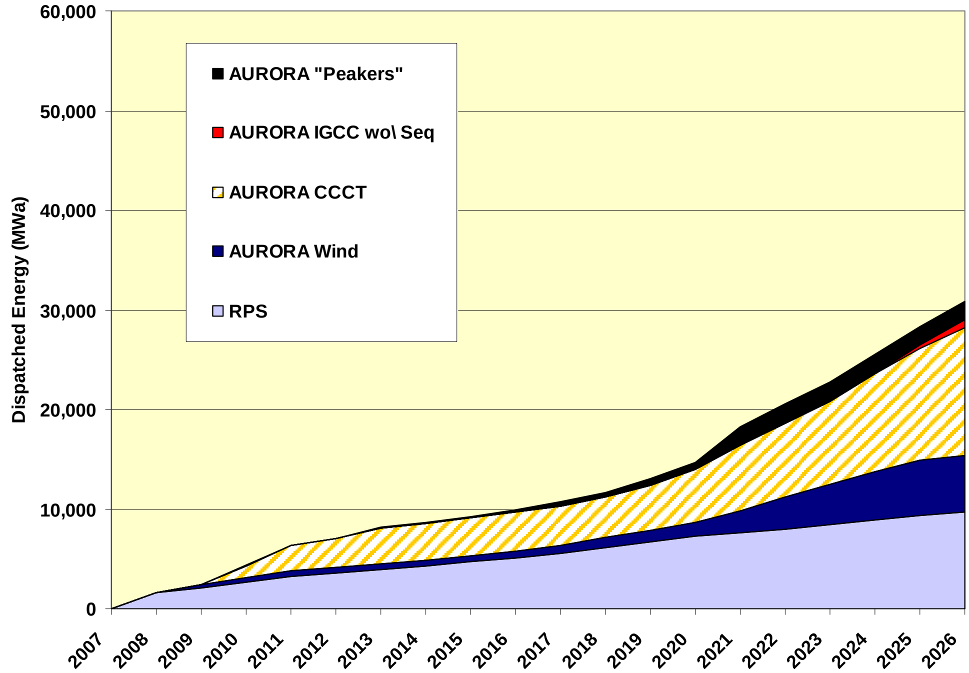

Figure 16: Forecast WECC incremental resource mix of the high capital cost case based on dispatched energy

Conclusions

This is the first time that the Council's power price forecast has included the impact of renewable portfolio standards (RPS) recently implemented in Montana, Oregon, Washington, and many other western states. The mandated addition of large amounts of renewable generating resources to the western power system is forecast to dampen wholesale power prices in the near term. In the long-term, regulation of carbon dioxide emissions offsets the dampening effect of the RPS additions and is expected to significantly increase wholesale power prices.

The Council's forecast pegs wholesale power prices below levels where independent developers can expect to recover the full costs of constructing and operating the new renewable generating resources by selling power into the wholesale spot market. An important implication of this result is that Northwest ratepayers and utility regulators are likely to see, at the same time, declining wholesale power prices and rising retail rates.

In the Northwest, retail electricity rates are predominately cost-based rates. The electricity rates of both consumer-owned and investor-owned utilities are administratively set to recover the expected cost of providing service. Therefore, unlike the forecast near-term competitive wholesale power market prices, utilities' retail electricity rates can be expected to reflect the full capital cost associated with construction of the new RPS resources, as well as the cost of operating the resources.

The divergent direction of wholesale power prices and retail electricity rates can create strong incentives for utilities and their customers to rely more heavily on the short-term wholesale power markets for their energy needs. However, as the region saw during the western electricity crisis of 2000-01, there can be significant risk associated with this strategy.

Another important implication of a growing divergence between wholesale and retail prices is that direct use of the Council's forecasted power prices as "avoided costs" in conservation and generating resource assessments may not be appropriate in all cases. The cost of future resource development, measured in dollars per megawatt-hour (or cents per kilowatt-hour) is often referred to as an avoidable cost or more commonly as an "avoided cost." By comparing the cost of specific conservation measures or generating resources to the region's "avoided cost," the Council and others have evaluated the cost-effectiveness of pursuing these resources. In the past, the Council used its wholesale power price forecast as its best estimate of the region's future resource development cost.

The region may need a different methodology for estimating its avoided cost not only because of the divergence between wholesale power prices and retail electricity rates, but also because the terms and conditions of the region's RPS statues make it difficult to consider conservation a full alternative to RPS resource development. For example, under Washington's 15 percent renewable by 2020 target, every megawatt-hour of conservation only avoids 0.15 megawatt-hours of RPS resource development. In other words, the RPS avoidance rate of conservation is 15 percent. In Washington, and many other RPS states, conservation can be expected to primarily result in utility surplus sales or avoided purchases in the wholesale power market. A utility facing an unfilled 15 percent RPS mandate will see an avoided cost comprised of 15 percent of the full cost of the least-cost available qualifying RPS resource plus 85 percent of the forecast wholesale power market prices.

The following chart illustrates this blending of forecast wholesale power prices and the full cost of RPS resource development to arrive at an overall avoided cost.[17] Avoided costs are shown for the four load segments used in the Council's assessment of the cost-effectiveness of conservation measures - many of which are most effective at specific times of day.

[17] The blending is 20 percent of the full cost of a wind resource in 2020, and 80 percent of the forecast wholesale power market prices.

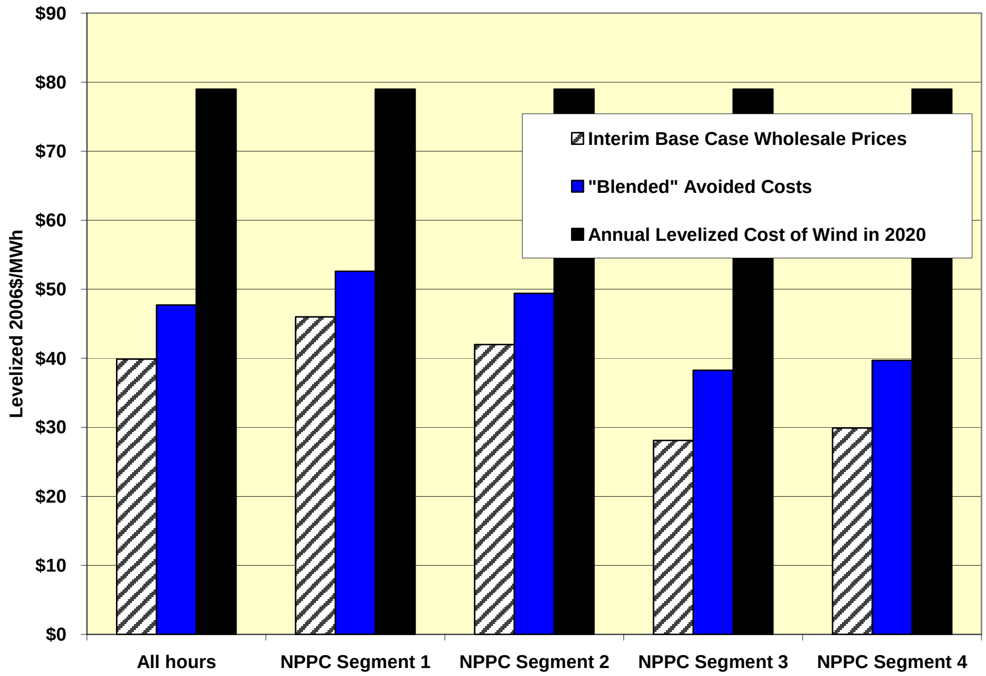

Figure 17: Potential "blended" avoided cost methodology

Avoided costs can be expected to differ for different utilities. For a utility that expects to be resource sufficient after complying with state RPS requirements, avoided costs are largely determined by the rate at which the RPS resource additions are avoidable by pursuing conservation. As indicated above, under most state RPS statues conservation and renewable resource development do not compete on an equal basis. For a surplus utility that does not face a state RPS requirement, avoided costs would equal forecasted wholesale power market prices. This is the cost of avoided purchases or the value of surplus sales in the wholesale power market. For a utility that expects to be resource deficient, avoided costs are determined by the full cost of its expected resource expansion. This is the case for a utility that does not face a state RPS requirement or a utility that is deficit after complying with a state RPS requirement.

The Council intends to more fully address avoided cost issues and the role of conservation in reducing the region's carbon emissions in its upcoming Sixth Power Plan.