REVISED DRAFT

WHOLESALE POWER PRICE FORECAST FOR THE FIFTH POWER PLAN

March 3 2004

This paper describes the final draft wholesale power price forecast proposed for use in the Northwest Power and Conservation Council's Fifth Power Plan. The price forecast is an estimate of the future price of electricity as traded on the wholesale, short-term (spot) market at the Mid-Columbia trading hub. This price represents the marginal cost of power over the planning period and is used by the Council in assessing the cost-effectiveness of conservation and new generating resource alternatives. The price forecast is also used to estimate the cost implications of policies affecting power system composition or operation. An ancillary product of the price forecast is a forecast of the future WECC and regional resource mix. The forecast resource mix is used in GENESYS, the Council's system reliability assessment model, for forecasting the fuel consumption and environmental effects of future power system configurations and as the base resource portfolio for the Council's portfolio risk analyses.

The next section describes the base case forecast results and a summary of underlying assumptions. The subsequent section describes the modeling approach. The final section describes underlying assumptions in greater detail and the results of sensitivity tests conducted on certain assumptions.

BASE CASE FORECAST

The "Current Trends" forecast is based on average loads, fuel prices and hydropower conditions, and extrapolation of current trends with respect to technological development, energy-related policies and other factors affecting the market price of electricity. These assumptions, summarized in Table 1, and the resulting forecasted resource mix and prices are not necessarily "the right things to do", and will not necessarily reflect the Council's recommendations for the Fifth Power Plan. On completion of the portfolio risk studies and the development of recommendations for the plan, one or more additional price forecasts will be developed to illustrate the effect of the Council's recommendations on future power prices.

The forecast levelized cost of power at the mid-Columbia trading hub for the period 2004 through 2025 is $36.50 per megawatt-hour (year 2000 dollars[1]) (Figure 1). In Figure 1, the current forecast is compared to two earlier forecasts - the preliminary draft forecast released in September 2002 (levelized value of $38.00/MWh) and the forecast prepared in conjunction with the Council's Adequacy and Reliability Study of February 2000 (levelized value of $29.90/MWh).

[1] All prices cited in this paper are in constant year 2000 dollars unless noted otherwise.

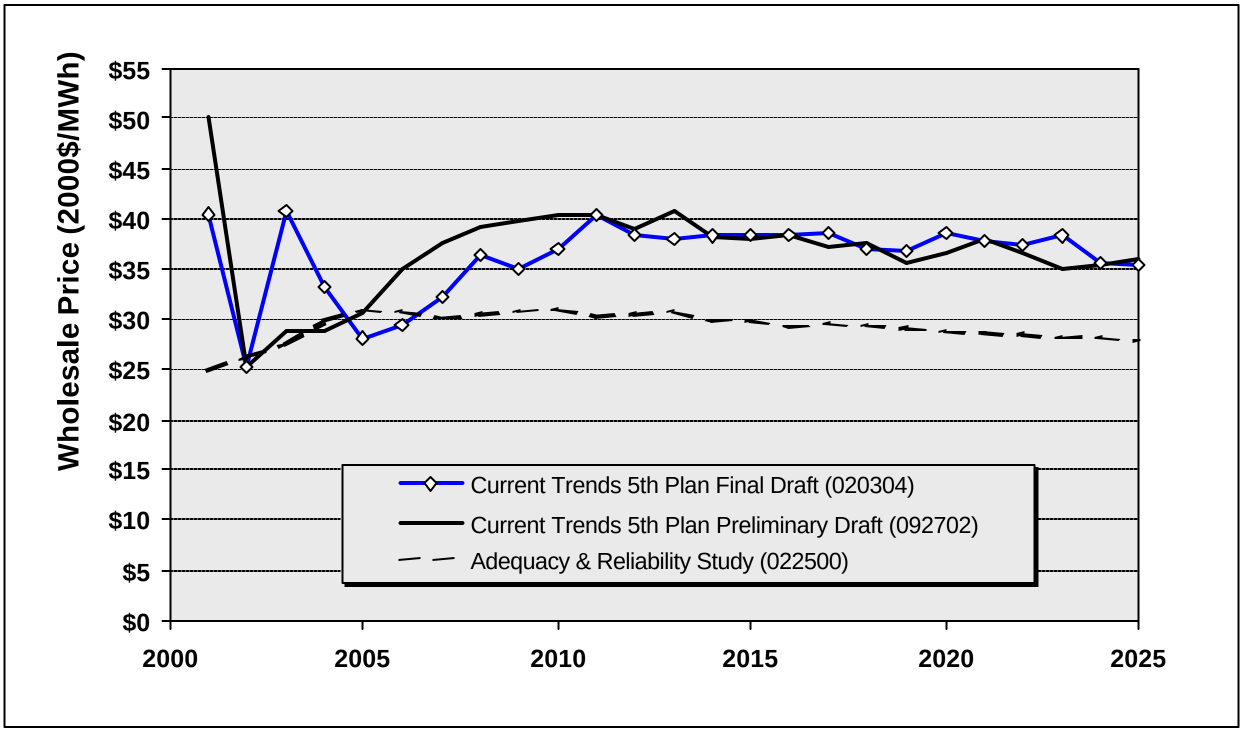
Table 1: Summary of assumptions underlying the base case Current Trends forecast

Hydropower	Average hydropower conditions
Fuel prices	5th Plan revised draft forecast, Medium case (April 2003)
Loads	5th Plan revised draft sales forecast, Medium case (April 2003)
Existing resources	Resources in service Q1 2003 Additions under construction Q1 2003 Retirements scheduled Q1 2003 Forecast state renewable portfolio standard and & system benefit charge acquisitions
New resource options	Gas-fired combined-cycle Wind Coal steam-electric Gas-fired simple-cycle Central-station solar photovoltaics Demand response Suspended projects > 25% complete
Inter-regional transmission	2003 WECC path rating Scheduled upgrades Q1 2003
Climate change policy	Oregon CO_2 standard, phased in
Renewable resource incentives	Continued federal production tax credit Green tag revenue
Intermittent resource penetration limit	20 - 25% of installed capacity by load-resource area

The initial years of the forecast conform to historical price behavior. Prices are shown declining from 2000-01 highs, than rising in 2002 as a result of gas prices increases. Forecast prices decline from 2003 highs as gas prices ease, then rise through 2010 as loads recover and the current capacity surplus is exhausted. Average prices are forecast to be stable through the remainder of the planning period as slowly increasing natural gas prices are offset by improved combined-cycle efficiency and increasingly more cost-effective windpower. Not forecast beyond 2003 are likely episodes of price excursions resulting from volatility in the gas market or poor hydro conditions.

The annual average prices of Figure 1 conceal seasonal price variation that develops as the current capacity surplus is worked off. This seasonal variation is shown in the plot of monthly average prices in Figure 2. A strong August peak is fully developed by 2010, and later broadens to include July. This seasonal price peak is driven by Southwestern air-conditioning loads, as shown in Figure 2 by the coincidence of Mid-Columbia price and Southern California loads. The strong seasonal price peak adds value to summer-peaking resources such as irrigation efficiency improvements.

Figure 1: Current and recent forecasts of average annual wholesale power price at the Mid-Columbia trading hub



Forecast daily variation in price is significant as well, with implications for the cost-effectiveness if different conservation measures. Shown in Figure 3 is a snapshot of the hourly forecast for the first week of August 2004, illustrating typical daily price variation.

A table of forecast annual average prices for the Mid-Columbia trading hub and other Northwest pricing points is provided in Appendix A. Monthly and hourly price series are available from the Council on request.

The forecast WECC resource mix associated with the Current Trends forecast is shown in Figure 4. Factors at work in the 2004 - 25 period include load growth, slowly increasing natural gas prices, new resource cost reductions from technological improvement, continued renewable resource incentives and slowly increasing costs of offsetting a portion of carbon dioxide (CO_2) production. Resource changes over time include the retirement of most existing gas-fired steam-electric capacity and addition of approximately 6,000 megawatts of renewable resources as the result of state renewable portfolio standards and system benefit charges. Market-driven resource additions include 42,000 megawatts of combined-cycle plant, 14,000 megawatts of coal capacity, 33,000 megawatts of wind capacity and 2400 megawatts of gas peaking capacity. About 8000 megawatts of solar photovoltaics capacity are added near the end of the planning period. The 2025 resource mix in capacity terms includes 32% natural gas, 23% hydropower, 18% coal and 15% wind. Proportions with respect to average energy are 30% natural gas, 20% hydropower, 30% coal and 9% wind. Not shown in the figure are about 9000 megawatts of short-term demand response capability assumed to be secured between 2007 and 2015.

Figure 2: Forecast monthly average wholesale power price at the Mid-Columbia hub compared to selected regional loads

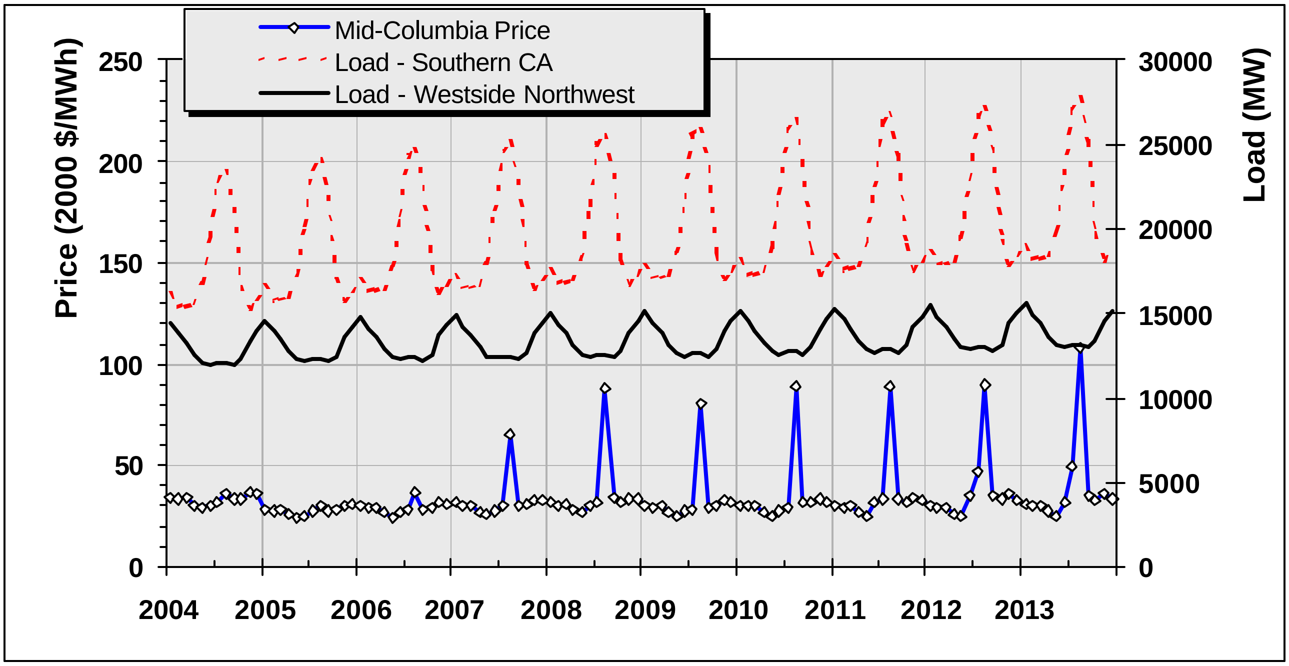


Figure 3: Illustrative hourly price behavior, Mid-Columbia hub, August 1 - 7, 2004.

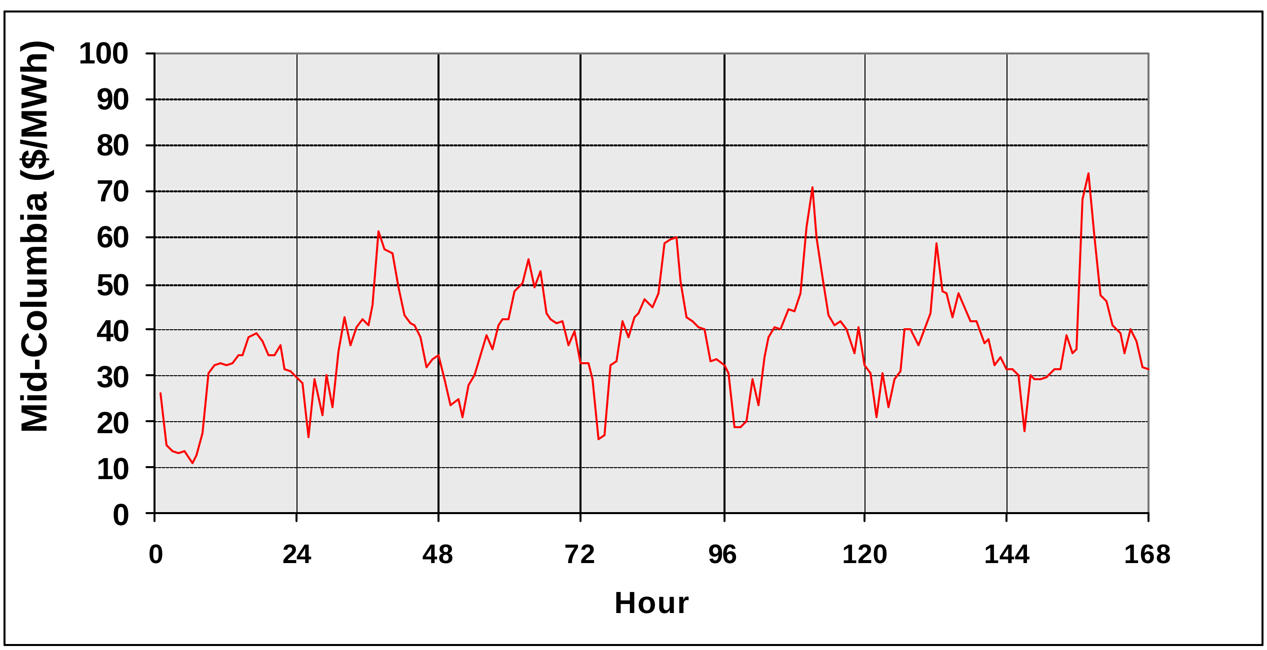
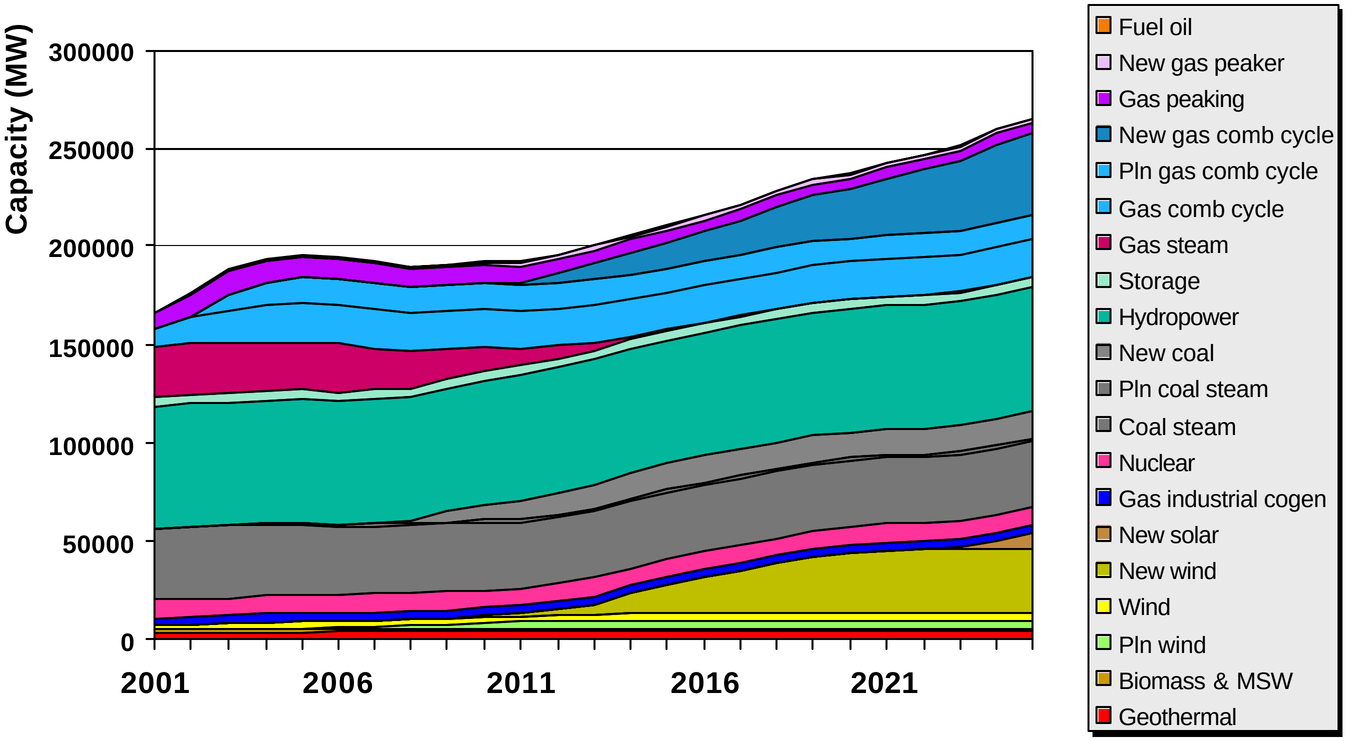


Figure 4: Forecast WECC resource mix



The Northwest resource mix is shown in Figure 5. The hydropower component (which does not change) has been omitted from Figure 5 to emphasize changes among other resource types. The principal resource additions are 2000 megawatts of coal, about 7000 megawatts of wind and statutory additions of about 1200 megawatts of renewables funded by state system benefit charges. About 600 megawatts of new combined-cycle capacity is added at the very end of the planning period. The principal components of the regional resource mix in 2025 in capacity terms include 62% hydropower, 18% wind[2], 11% coal and 9% natural gas. In energy terms, the components are 56% hydropower, 18% coal, 12% natural gas and 8% wind. Not shown in the figure is the assumption that about 1900 megawatts of short-term demand response capability will be secured between 2007 and 2015.

APPROACH

The Council forecasts wholesale power prices using the AURORA™ electricity market model[3]. AURORA forecasts wholesale power prices based on the variable cost of the most expensive generating plant or increment of load curtailment needed to meet load for each hour of the forecast period. Preparing a long-term forecast using AURORA is a two-stage process (Figure 6). First, a forecast of capacity additions and retirements (beyond those currently scheduled) is

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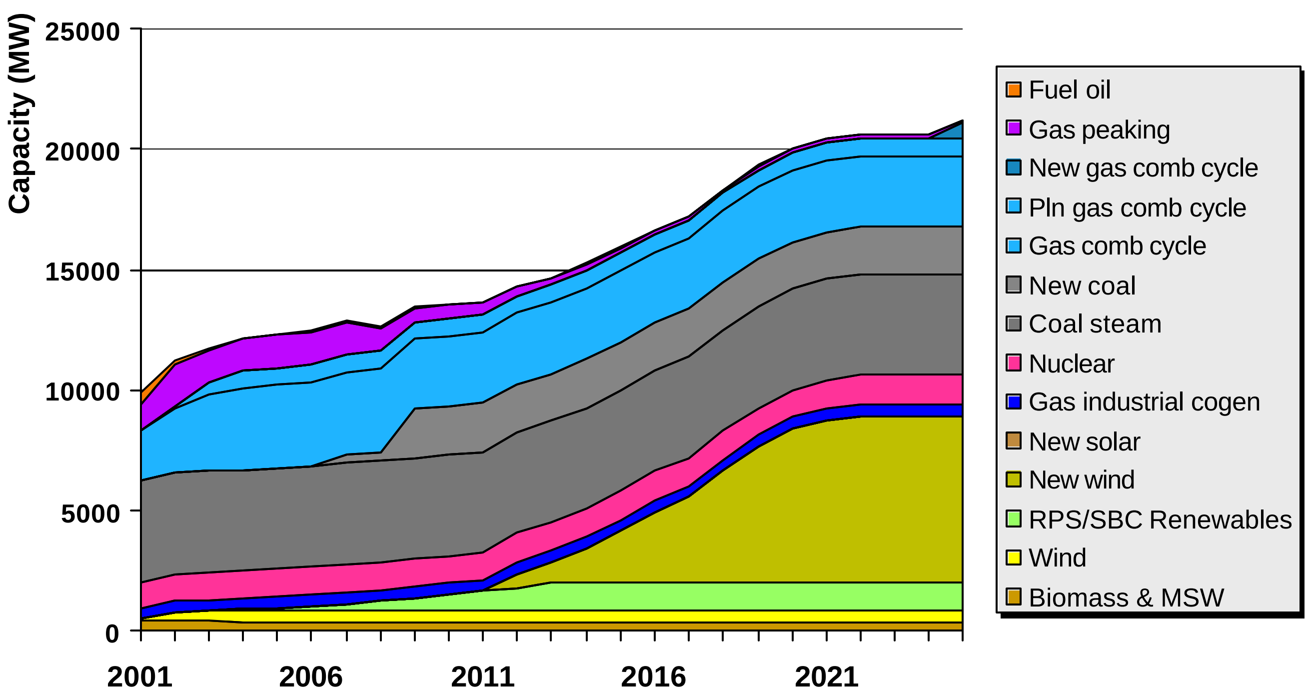
[2] Assuming that the majority of state system benefit charge acquisitions are wind.

[3] The AURORA™ Electricity Market Model was developed and is offered by EPIS, Inc. of West Linn, Oregon. EPIS may be contacted by phone at 503-722-2023 or by e-mail at info@epis.com. The EPIS website is www.epis.com.

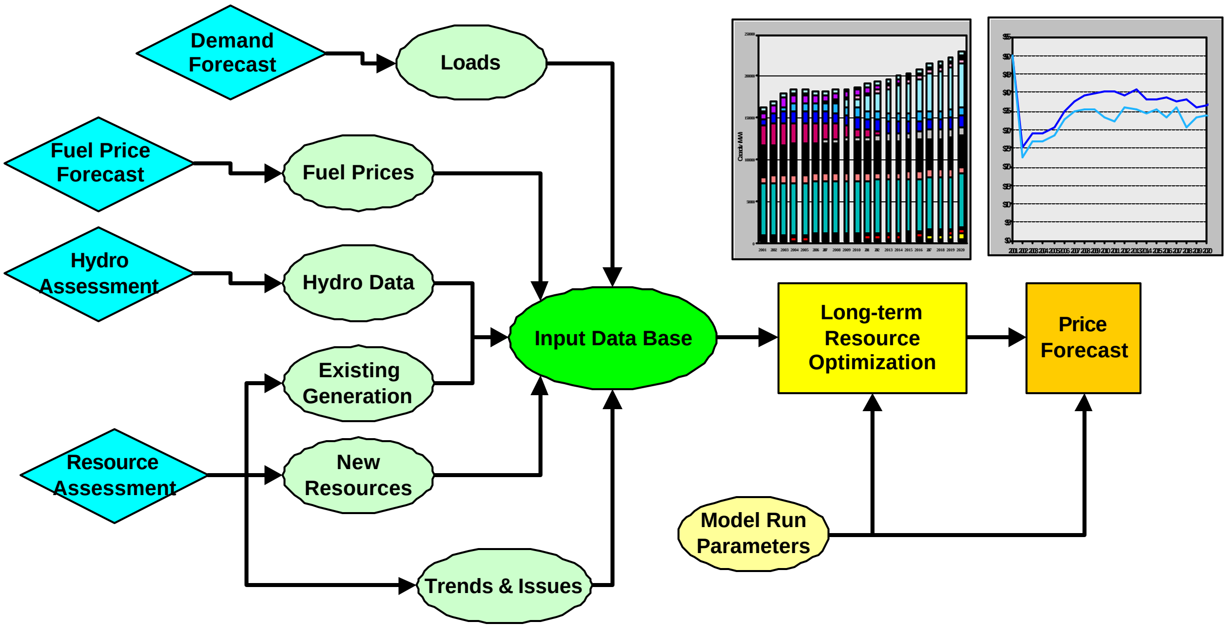
developed using AURORA's long-term resource optimization logic. This is an iterative process, in which the present values of possible resource additions and retirements are calculated for each year over the study period. Existing resources are retired if market prices are insufficient to meet future maintenance and operation costs. New resources are added if forecast market prices are sufficient to cover the fully allocated costs of resource development, maintenance and operation, including a return on the developer's investment. Once the mix of resources for the period of interest has been developed, power prices are forecast by dispatching the resulting resource portfolio against forecast loads.

Figure 5: Forecast Northwest resource mix (hydro omitted)



As configured by the Council, AURORA simulates power plant dispatch in each of sixteen load-resource zones comprising the Western Electricity Coordinating Council (WECC) electric reliability area (Figure 7). These zones are generally defined by major transmission constraints and are each characterized by a forecast load, existing generating units, scheduled project additions and retirements, fuel price forecasts, load curtailment alternatives and a portfolio of new resource options. Transmission interconnections between the areas are characterized by transfer capacity, losses and wheeling costs. The load within a load-resource zone may be served by native generation, load curtailment, or by imports from other load-resource areas if economic and if transmission transfer capability is available.

Figure 6: Price forecasting process



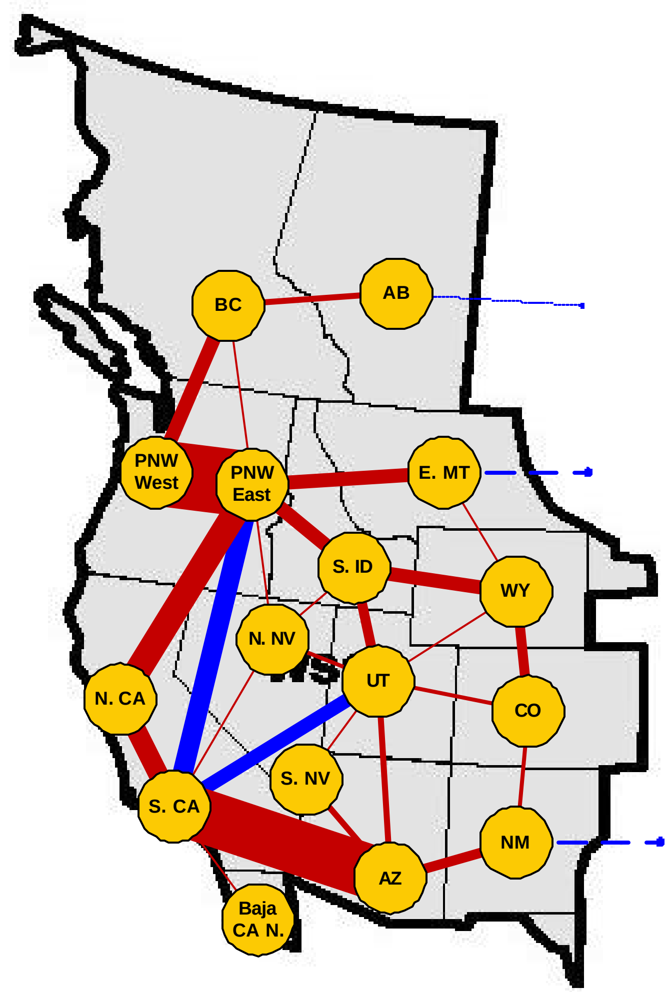
DATA, ASSUMPTIONS AND SENSITIVITIES

Forecasts and assumptions including future loads, fuel prices, Northwest hydropower characteristics, new resource characteristics, and energy and environmental policies are developed by the Council with the assistance of its advisory committees to accurately characterize factors significant to the Northwest.

The Current Trends forecast assumes continuation of current economic, technical and energy-related policy trends. This case assumes medium loads and fuel price forecasts and average long-term water, fuel price and load conditions[4]. The effects of fuel price volatility and water conditions on long-term average electricity prices are calculated. However, with the exception of currently relatively high gas prices, price excursions resulting from episodic gas price and hydro volatility are not modeled.

[4] Average water conditions are adjusted downward, and medium fuel prices are adjusted slightly upward to reflect the average effect of water and fuel price volatility on power prices.

Figure 7: Load-resource areas



Loads

The Council's revised draft medium case 20-year sales forecast is the basis for the Current Trends price forecast. The load forecast includes in-region transmission and distribution losses and the effects of price-induced and programmatic conservation[5]. In the medium case, loads are forecast to grow at an average annual rate of approximately 1 percent per year from 20,080 average megawatts in 2000 to 25,420 average megawatts by 2025. Because of the decline in loads during the first portion of this period, the annual growth rate from 2003 to 2025 is higher than average (1.5 percent per year), with annual increases of 330 average megawatts.

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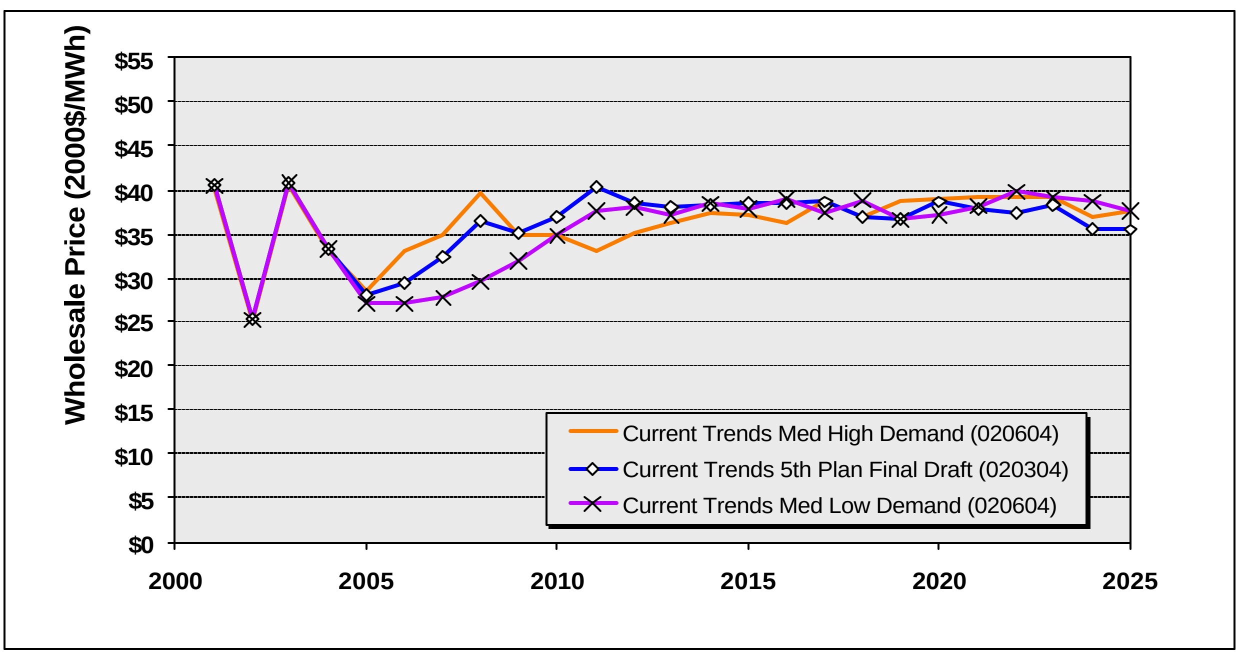
[5] The demand forecast used for draft power forecast is based on estimates of programmatic conservation obtained from the Fourth Power Plan. Preliminary results suggest that the conservation potential of the Fifth Power Plan may be considerably larger that that of the Fourth Plan. Pending completion of the final power price forecast for the Fifth Power Plan, which will incorporate the conservation estimates of the Fifth Plan, the sensitivity analysis for medium load growth, described below, provides a sense of the effects of additional conservation potential.

The general approach used to forecast loads for WECC areas outside the Northwest is to calculate future growth in electricity demand as a historical growth rate of electricity use per capita times a forecast of population growth rate for the area. Exceptions to this method were California where forecasts by the California Energy Commission were used, and the Canadian provinces, where electricity demand forecasts are available from the National Energy Board.

WECC loads are forecast to grow from 91,200 average megawatts in 2000 to 133,900 average megawatts in 2025. Load-resource areas outside of the Northwest have not experienced the extent of load loss in early years as the Northwest and are also are forecast to see more rapid average long-term load growth than the Northwest. The average annual 2000 through 2025 load growth rate for the WECC as a whole is expected to be 1.6%. Annual average medium case load growth rates for each load-resource area are provided in Appendix B.

The Council forecasts a range of load growth to assess the implications of load growth uncertainty on power prices and resource development recommendations. The most likely range of demand growth is believed to be between the medium-low (0.4%/yr) and medium high (1.5%/yr) cases. Medium low and medium-high load growth rates for the areas other than the Northwest were estimated by adjusting the medium-case long-term growth rates for each area by the load growth rate case differences developed for the Northwest. Faster load growth in the medium-high load case leads to more rapid price recovery, and somewhat higher near-term power prices (Figure 8). Prices then drop below the base case in the mid-term. Prices rise to a level somewhat higher than the base case in the long-term. Because of the lower mid-term prices, the levelized Mid-Columbia price for the medium-high load growth case is the same as for the base case ($36.50/MWh). The slower load growth in the medium-low case leads to extended price recovery. Prices rise to about the same level as the base case in the long-term, since the marginal resources are similar. The levelized forecast Mid-Columbia price is lower in this case, $35.40/MWh.

Figure 8: Price sensitivity to load growth uncertainty



Additional information regarding the load forecasts is provided in Council document 2003-6 *Revised Draft Forecast of Electricity Demand for the Fifth Power Plan* (http://www.nwcouncil.org/library/2003/2003-6.htm).

Fuels

The Council's revised draft medium case 20-year fuel price forecast is used for the base case power price forecast. Delivered coal and natural gas prices for each load-resource area are based on Western mine mouth coal and average U.S. natural gas wellhead price forecasts, respectively. A chain of basis differentials and a seasonal adjustment are added to the base prices to arrive at monthly delivered fuel prices for each load-resource area. For example, the price of natural gas price delivered to a power plant located in western Washington or Oregon is based on the annual average U. S. wellhead price forecast, adjusted by price differentials between wellhead and Henry Hub, Louisiana, Henry Hub and AECO hub, Alberta, AECO and (compressor) Station 2, British Columbia, and finally, Station 2 and western Washington and Oregon. A monthly adjustment is applied to the AECO - Station 2 differential. The base fuel price forecasts and derivation of load-resource area prices are fully described in Council Document 2003-7 *Revised Draft Fuel Price Forecasts for the Fifth Power Plan,* http://www.nwcouncil.org/library/2003/2003-7.htm.

In the medium case, Western mine mouth coal is forecast to decline from $0.51/MMBTu in 2000 to $0.42/MMBtu in 2025 (constant 2000 dollars). Following a decline from the 2000 high of $6.71/MMBtu to $5.61/MMBtu in 2005, distillate fuel oil prices are expected escalate slowly to $6.00 in 2025 at a rate of 0.3%/yr. The U.S. average wellhead natural gas price is forecast to decline from current highs to $3.25/MMBtu in 2005, then rise on average at 0.5%/yr to $3.60/MMBtu in 2025 (year 2000 dollars). The 2025 wellhead natural gas price is based on the expected cost of imported liquified natural gas.

Forecast medium case delivered prices for selected fuels are plotted in Figure 9. The fuel prices of Figure 9 are shown as fully variable ($/MMBtu) to facilitate comparison. For AURORA, fuel prices are allocated into fixed ($/kW/yr) and variable components to reflect costs, such as pipeline reservation costs that are essentially fixed in the short-term.

Because of the importance of natural gas fuelled generation, now and in the future, uncertainty regarding future natural gas prices could substantially affect future resource mix and power prices. Sensitivity analyses were run over the range of Council fuel price forecasts, yielding the price forecasts of Figure 10. The levelized net present value price for the four cases are $37.70, $36.50, $33.40 and $31.10 for the high, medium-high, medium-low and low fuel price forecast cases, respectively. As shown in Figure 10, though the higher fuel price cases have a significant impact on power prices in the near-term, the effect in the longer-term is much less significant. Over the long-term, higher fuel prices shift resource development from natural gas to wind and coal, tempering the impact of fuel price increases. In contrast, the downward shifts of power prices in the lower fuel price cases remain significant throughout the planning period. This appears to result from a shift to lower-cost gas combined-cycle plants from wind and coal over the period.

Figure 9: Price forecast for selected fuels (medium case)

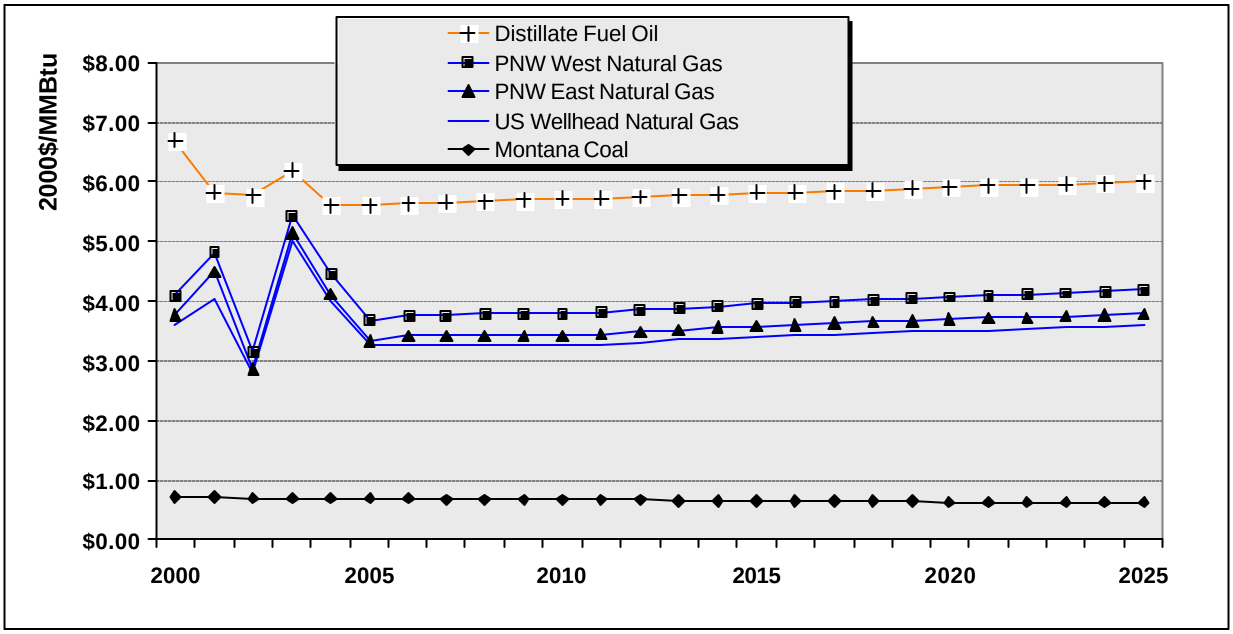
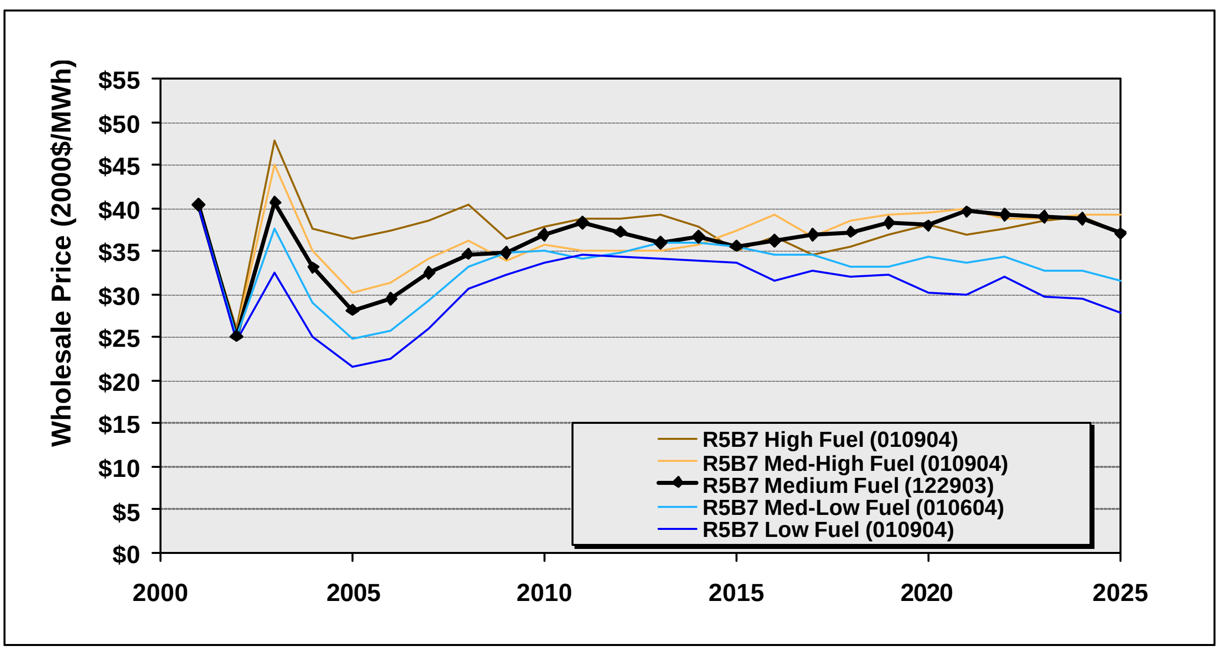


Figure 10: Sensitivity of power price to fuel price forecast case (R5B7)



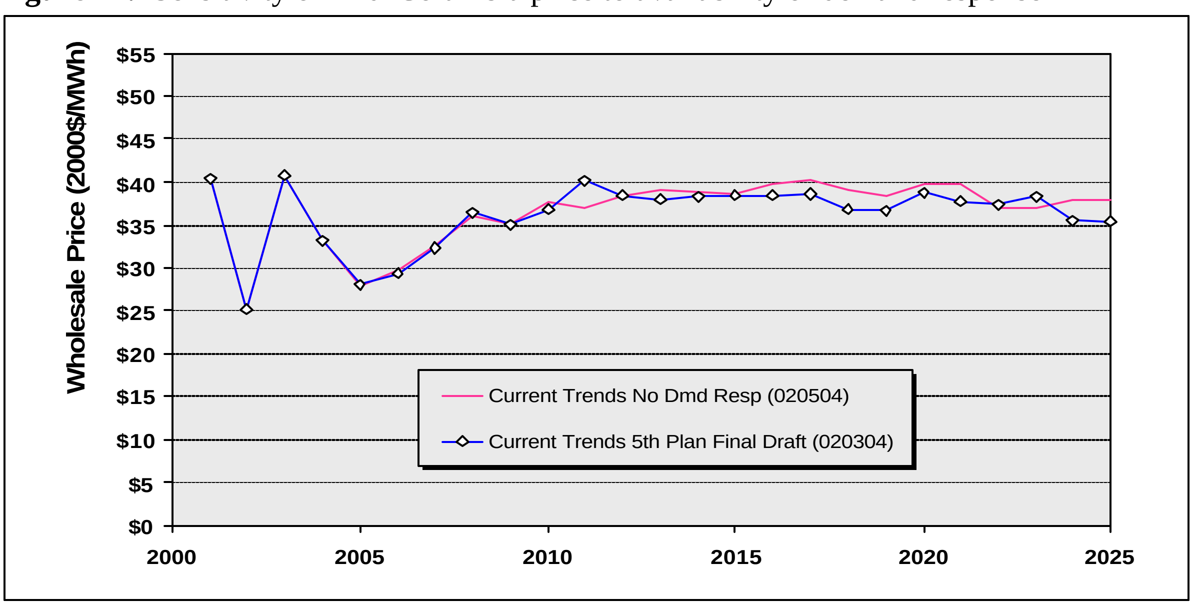
Demand Response

The Council believes that demand response is a potentially attractive alternative to construction of seldom-used peak generating resources. Demand response is a change in the level or quality of service that is voluntarily accepted by the consumer, usually in exchange for payment. Demand response can shift load from peak to off-peak periods, reducing the cost of generation by shifting the marginal dispatch to more efficient or otherwise less-costly units. Demand response may also be used to reduce the absolute amount of energy consumed to the extent that end-users are willing to forego electricity consumption at times of high electricity cost. The attractiveness of demand response is not only its ability to reduce the overall cost of supplying electricity, it also rewards end users for reducing consumption during times of high prices and possible supply shortage. Demand reduction also offers the many of the environmental benefits of conservation.

Formerly, Bonneville maintained an infrequently used demand response capability through its direct service industry contracts. Ad-hoc efforts at implementing demand response capability were undertaken during and subsequent to the power crisis of 2000 and 2001. Preliminary analysis by the Council suggests that up to 16 percent of load might be offset during times of high prices through various forms of time-of-day pricing and negotiated agreements at a cost of $50 to $400/MWh. For the base case forecast, we assume that 50% of this potential is secured through energy-saving demand response mechanisms, beginning in 2005 and ramping up through 2015. Similar penetration is assumed for all load-resource areas.

Though demand response has been successfully developed in other regions, efforts to assess and implement demand response in the Northwest (other than the former Bonneville DSI contracts) have been limited and inconclusive. Because efforts to develop demand response capability may less successful than assumed in the base case, a sensitivity analysis omitting the demand response resource was run. As expected (Figure 11), the forecast power price rises in the mid and longer-term as more expensive new resources are developed to substitute for the foregone demand response. Levelized power prices increase $0.50/MWh, from $36.50 in the base case to $37.10 in the sensitivity case.

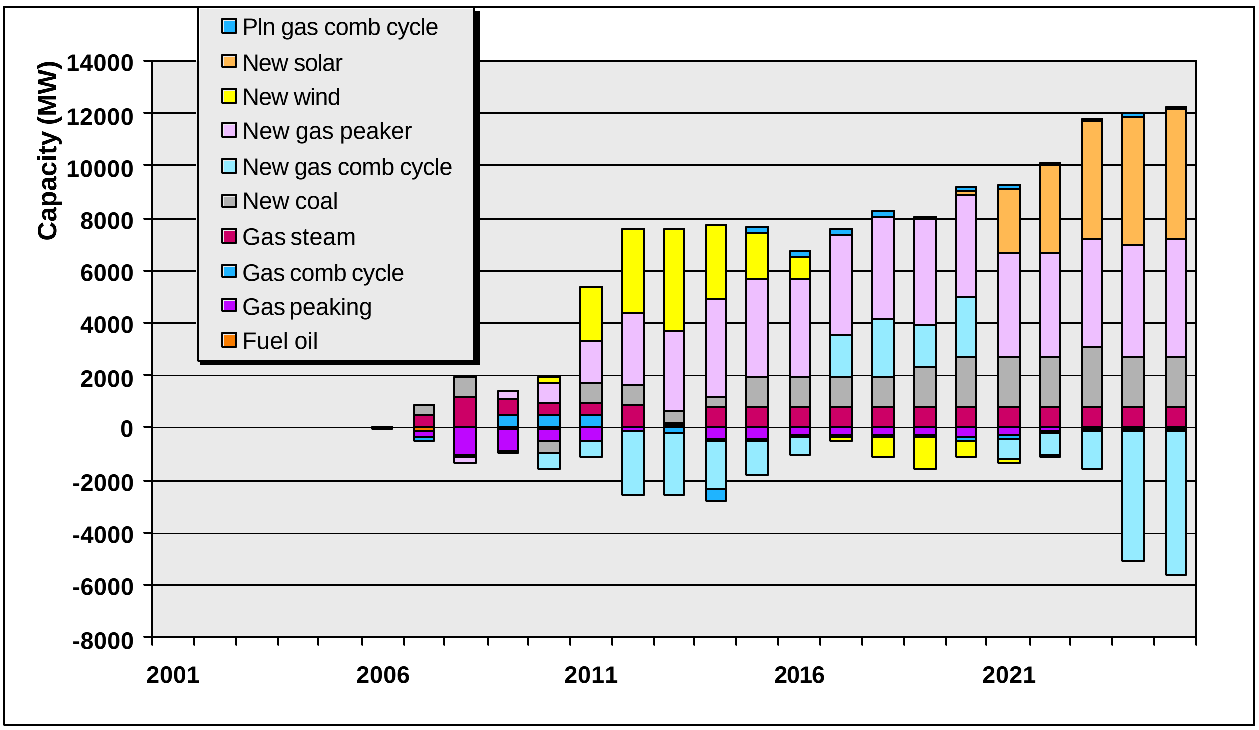
Figure 11: Sensitivity of Mid-Columbia price to availability of demand response



The resources developed in lieu of demand response are shown in Figure 12 on a cumulative annual basis for WECC as a whole. As expected, gas-fired peaking units comprise a large portion of the resources developed in the absence of demand response. Somewhat surprisingly, the development of new wind and, later, solar resources advances to substitute for the demand response. More new coal capacity, and over the long-term, less combined-cycle capacity is observed.

Additional discussion of demand reduction is provided in Council Document 2002-18: Demand Response (http://www.nwcouncil.org/library/2002/2002-18.htm).

Figure 12: Resources developed in lieu of demand response



New Generating Resource Alternatives

AURORA™ adds capacity when the net present value cost of adding a new unit is less than the net present market value of the unit. Because study run time is sensitive to the number of available new resource alternatives, a compromise must be drawn between the need to reasonably portray the diversity of future resource alternatives and study time considerations. Some resource alternatives such as gas combined-cycle plants and wind are currently significant and likely to remain so. Others, such as new hydropower or biomass, are unlikely to be available in sufficient quantity to significantly influence future power prices. Some, such as solar photovoltaics are not significant at present, but may become significant as costs decline. Finally, some resources, such as gas-fired reciprocating generator sets are not significantly different from simple-cycle gas turbines with respect to effect on power prices. With these considerations in mind, the new resources modeled for this forecast included natural gas combined-cycle power plants, two cost blocks of wind power plants, coal-fired steam-electric power plants, natural gas simple-cycle gas turbine generating sets and central-station solar photovoltaic plants.

Gas-fired combined-cycle plants have been the "resource of choice" since the early 1990's. Reasons include high thermal efficiency, low environmental impact, excellent operating flexibility and low natural gas prices for much of this time. Technology improvements are expected to continue, helping offset expected real increases in natural gas prices. Though over 7,000 MW of additional gas combined-cycle capacity are currently permitted in the Northwest, the future role of this resource is sensitive to the cost of natural gas and global climate change policy. Higher gas prices could shift development to coal. Conversely, more extensive carbon dioxide offset requirements might favor combined-cycle plants because of their relatively low carbon dioxide production. The representative natural gas combined-cycle power plant defined for this forecast is a 540 MW 2x1 configuration F-class plant with 70 MW of power augmentation (duct-firing) capability. Combined-cycle and other new resource assumptions are summarized in Table 1.

Wind power has progressed from niche to mainstream over the past decade. Factors include improved reliability, cost reduction, financial incentives and emerging interest in the hedge value of wind with respect to gas prices and GCC policy. The cost of wind power (sans financial incentives) is currently higher that that from gas combined-cycle or coal plants, but is expected to decline to competitive levels within several years. The future role of wind is dependent upon gas price, GCC policy, technological improvement, availability of transmission and shaping services and financial incentives. Higher gas prices increase the attractiveness of wind, particularly if there is expectation that coal may be subject to future carbon offset requirements. At current costs, it is infeasible to extend transmission more than several miles to integrate a wind resource area with the grid. This limits the availability of wind to prime resource areas close to the grid. As wind plant costs are reduced, feasible interconnection distances will extend, expanding wind power potential. Two cost blocks of wind were defined for this study - a lower cost block representing good wind resources and low shaping costs, and a higher cost block representing the next phase of wind development with somewhat less favorable wind (lower capacity factor) and higher shaping costs.

No coal-fired power plants have entered service in the Northwest since the mid-1980s. However, continuing decline in coal prices, improvements in technology and concerns regarding future natural gas prices have repositioned coal as a potentially economically attractive new generating resource. Conventional steam-electric technology would likely be the coal technology of choice in the near-term. Supercritical steam technology is expected to gradually penetrate the market and additional control of mercury emissions is likely to be required. Because no practical means of capturing and sequestering the carbon dioxide production of fossil power plants currently exists, the most feasible approach to the reduction of carbon dioxide from coal plants may be introduction of coal gasification technology. The higher thermal efficiency of this technology would reduce per kilowatt-hour carbon dioxide production. The representative new coal-fired power plant defined for this forecast is a 400-megawatt steam-electric unit. Costs and performance characteristics simulate a gradual transition to supercritical steam technology over the planning period (Table 2).

As described earlier, the Council views demand response as a promising approach to meeting peaking and reserve power needs. Supplementary ("duct") firing of gas combined-cycle plants can also help meet peaking or reserve needs at low cost. Additional requirements can be met by simple-cycle gas turbine or reciprocating generator sets. From a modeling perspective, the cost and performance of gas-fired simple-cycle gas turbines and gas-fired reciprocating engine-generator sets are sufficiently similar that only one need be modeled. The Council chose to model a twin-unit (2 x 47 megawatt) aeroderivative simple-cycle gas turbine generator set.

Solar power is one of the most potentially attractive and abundant power supply alternatives in the long-term. Economical small-scale applications of solar photovoltaics are found throughout the region where it is costly to secure grid service, however solar power is currently far more expensive than other bulk supply alternatives. Because of the potential for significant solar photovoltaic cost reduction, we also included central-station solar photovoltaics as a longer-term resource alternative.

Other power supply resources are available for future development, but in more limited quantity than those described above. One attractive alternative is cogeneration, where exhaust heat from gas turbine or reciprocating engines is used for process, space or water heating. This improves the overall efficiency of fuel use and often reduces net air emissions and other environmental impacts. Also attractive is the use of various bio-residues for power generation. Though typically small scale, these plants can produce useful energy from otherwise wasted material and simultaneously resolve waste disposal problems. A few small-scale environmentally acceptable hydropower projects remain available for development in the Northwest, and some additional potential is available through upgrade of older equipment at existing projects. Geothermal potential, once thought extensive, appears to be limited in quantity and has proven difficult and relatively expensive to develop. Nuclear power remains available for development, but is relatively expensive. Additional commercial development of nuclear power in the United States appears unlikely until a spent fuel disposal system is established and operation of new generation, modular, "passively safe" power plants is successfully demonstrated. None of these resource alternatives were modeled in this forecast.

Also included as new generating resource alternatives are four gas combined-cycle power plants in the Northwest for which construction has been suspended at an advanced stage. These are Grays Harbor, Mint Farm, Goldendale and Montana First Megawatts.

Table 2: Summary of new generating resource assumptions

	Unit Size (MW)	Capital Cost ($/kW)	Non-fuel Fixed O&M ($/kW/yr)	Non-fuel Variable O&M ($/MWh)	Trans Cost ($/kW/yr) & losses	Shaping Cost ($/MWh)	Heat Rate (Btu/kWh)	Operating Availability (%)	Northwest Potential (Units Avail/Dev in Base)
Natural gas combined-cycle gas turbine	540 MW baseload 610 MW peak.	$525	$8.10	$2.80	$15.00 1.9% losses	n/a	7030 (Baseload) 9500 (Peak increment)	90%	25/1
Natural gas single-cycle gas turbine	90 MW (2 x 45 MW units)	$600	$8.00	$8.00	None	n/a	9960	92%	20/0
Wind plant (Block 1)	100 MW	$1010	$20.00	$1.00	$15.00/fixed 1.9% losses	$4.00	n/a	28 - 36% [6]	40/40
Wind plant (Block 2)	100 MW	$1010	$20.00	$1.00	$15.00 1.9% losses	$8.00	n/a	26 - 34%	30/30
Coal steam-electric plant	400 MW	$1230	$40.00	$1.75	$15.00 1.9% losses	n/a	9550	84%	15/5
Central-station solar photovoltaic plant	100 MW	$6000	$15.00	$0	$15.00 1.9% losses	$8.00	n/a	22%	15/0

[6] Varies by load-resource area.

Transmission

Transfer capability between load-resource areas is modeled on the existing transmission system plus committed additions, as scheduled. The latter include scheduled upgrades to Path 15 between northern and southern California, and a scheduled upgrade to the interconnection between Baja California and southern California.

Financial incentives

To promote various forms of energy production, federal, state and local governments have, over many years, provided various government incentives for energy development, including research and development grants and favorable tax treatment. Tax incentives are durable, and the resource costs used in this forecast assume continuation of current federal incentives. Because of practical data development considerations, state and local financial incentives, such as sales and property tax exemptions are generally not modeled.

One federal incentive that significantly affects the economics of renewable resource development is the renewable energy production tax credit (PTC) and the companion renewable energy production incentive (REPI) for tax-exempt entities. Though these incentives expired in 2003, we assume their continuation (and applicability to solar as well as wind generation) in the base case forecast because of the apparent widespread support for their extension and expansion. However, because of controversy regarding other aspects of proposed federal energy legislation, extension of the PTC and REPI has not been as timely as originally foreseen. Moreover, the increasing magnitude of the projected federal budget deficit suggests that continued renewal of these incentives may not be as certain as believed when the base case assumptions were developed. The significance of the PTC and REPI was tested by a sensitivity case that assumed no extension of these incentives following 2003.

The absence of the production tax credit has, as expected, a significant effect on the development of renewable resources. Figure 13 illustrates the cumulative annual difference in WECC resource mix between the base case and the case without the renewable incentives. The development of new wind and solar resources is shifted back, with 8000 to 9000 fewer megawatts of wind capacity until the early 2020s when the available wind resource begins to be exhausted and the level of wind development between the two cases returns to parity. Solar development does not catch up to the base case, and somewhat surprisingly, combined-cycle development is about 5000 megawatts lower as well. New coal, new gas peaking and retained gas-steam units substitute for the foregone renewable and combined-cycle capacity.

Because the production tax credit provides a federal subsidy to the power system, prices increase in its absence (Figure 14). Forecast levelized Mid-Columbia prices increase by $0.70/MWh to $37.30/MWh.

Figure 13: Changes in WECC resource development in the absence of the renewables production tax credit

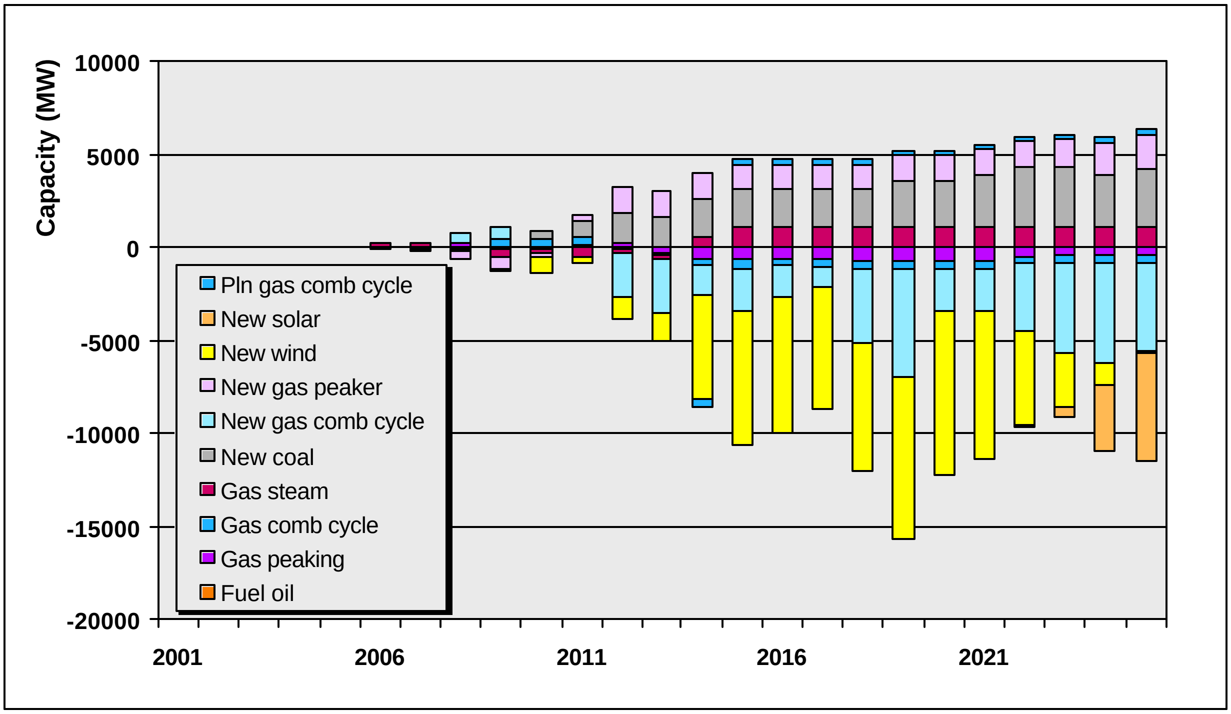
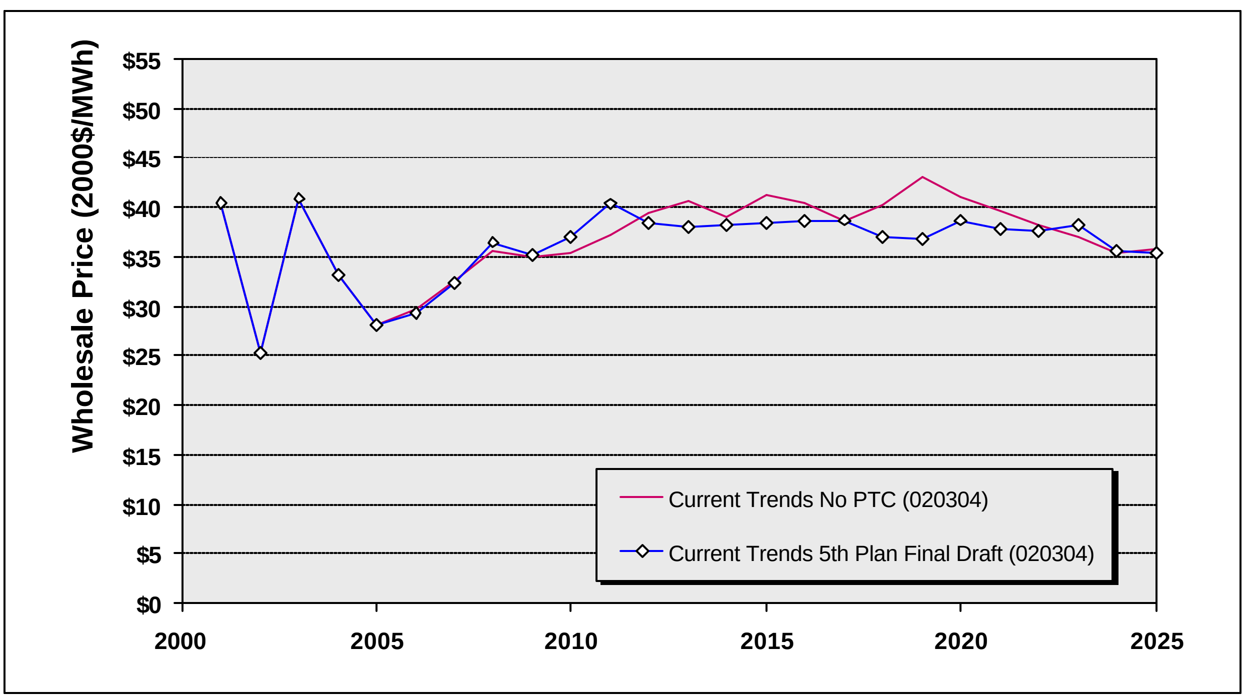


Figure 14: Sensitivity of Mid-Columbia price to renewables production tax credit



Global Climate Change Policy

In the absence of federal requirements for greenhouse gas reductions in the face of growing scientific evidence supporting the existence of anthropogenic global climate change, individual states are moving to establish controls on the production of carbon dioxide and other greenhouse gasses. Oregon has required 17 percent of carbon dioxide production of new power plants to be offset since 1997. Washington has required CO2 offsets for recently permitted projects on an ad-hoc basis and is planning to implement a consistent CO2 offset requirement for all new facilities. Recently, California has joined with Washington and Oregon to develop joint policy initiatives leading to a reduction of greenhouse gas production.

Carbon dioxide control requirements could significantly affect the future mix of generating resources and resulting power prices. The base case forecast assumes that the CO2 offset requirements similar to those in Oregon will be gradually adopted by other states and provinces, and that a uniform offset requirement at the Oregon level will be in-place throughout WECC by 2012. Because of increasing demand for offsets, the cost of offsets is assumed to rise from current levels of about $1/Ton CO2 to $30/Ton CO2 in 2025. Because of uncertainty regarding future CO2 control, two alternatives regarding CO2 control were considered in sensitivity analyses. One case assumes that CO2 offsets are required only Oregon and Washington through the study period. Because the offset market is assumed to be global the base case offset costs were retained.

The effect of removing CO2 offset requirements (except Oregon and Washington) is to shift resource development from natural gas to coal (Figure 15). Wind resource development is deferred, but returns to base case levels by the end of the forecast period. Solar development is approximately 3000 megawatts less than the base case by 2025. Prices are significantly lower in the mid and long-term (Figure 16). Forecast Mid-Columbia prices decline by $3.10/MWh to $33.50/MWh. CO2 production for the WECC region for the period 2004 - 25 increases by 5% to 10,611 million tons in this case.

A second sensitivity analysis approximated the nationwide cap and trade program proposed in the McCain Lieberman Climate Stewardship Act. McCain Lieberman would implement tradable emissions allowances to reduce CO2 production and five other greenhouse gasses. Reduction requirements would apply to large commercial, industrial and electric power sources. Beginning in 2010, allowances would be capped at 2000 levels. The cap would be reduced to 1990 levels beginning in 2016. A summary and analysis of the effects of the Climate Stewardship Act is available at http://www.eia.doe.gov/oiaf/servicerpt/ml/pdf/summary.pdf. The Climate Stewardship Act was defeated by a moderate Senate majority in November 2003. Here we assume that the Act passes in two years, and the Phase I cap goes into effect in 2012.

(The Climate Stewardship Act sensitivity case was not complete as of this writing)

Figure 15: Changes in WECC resource development with CO2 offsets limited to Oregon & Washington

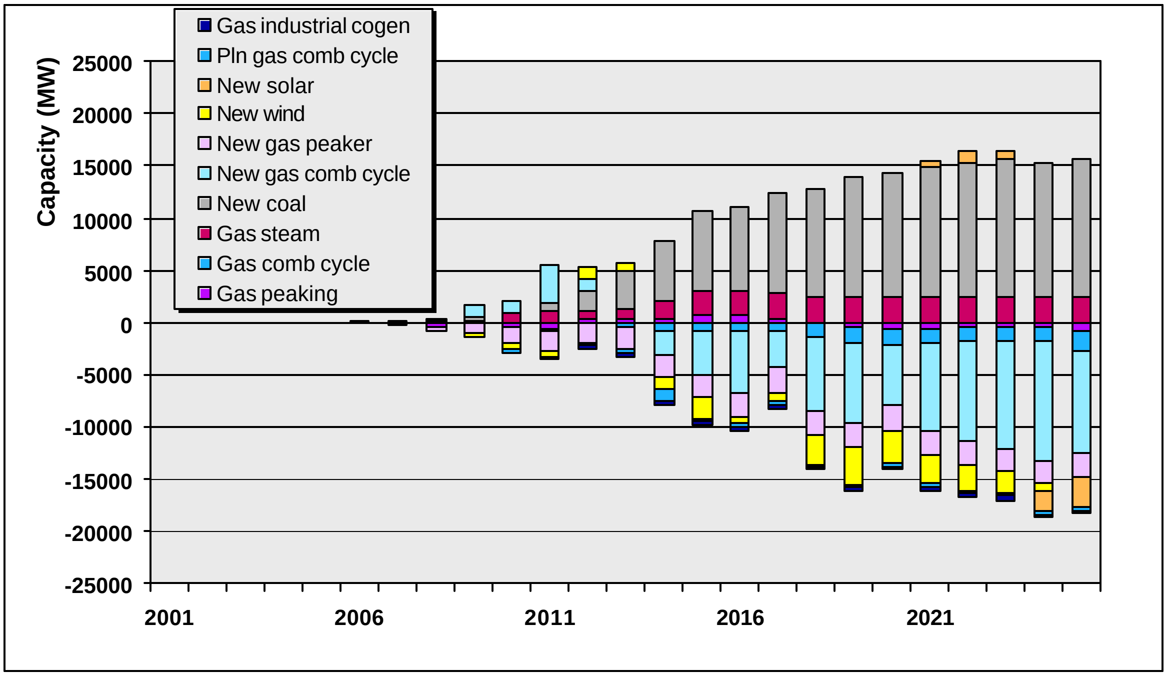
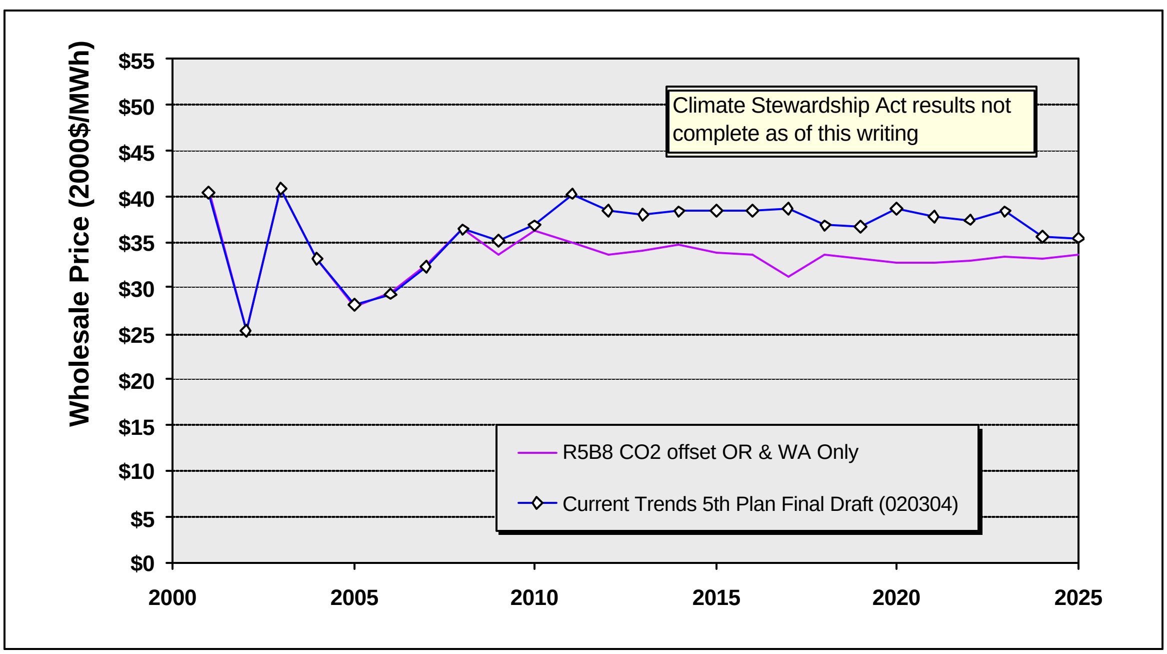


Figure 16: Sensitivity of Mid-Columbia price to removal of CO2 offset requirements (except Oregon and Washington)



Price Caps

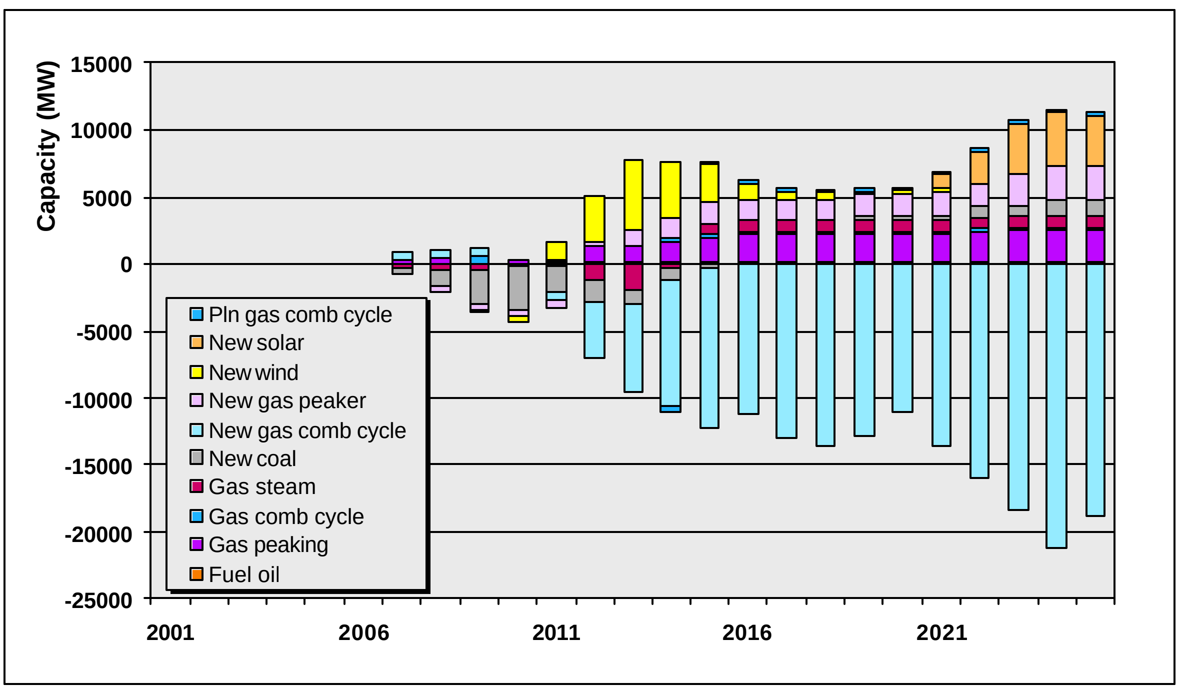
Following a year of extraordinary high power prices, the FERC implemented a floating WECC wholesale trading power price cap in June 2001. The original cap applied when California demand rose to within 7 percent of supply, and was based on a formula that estimated the cost of production from the most-expensive California plant. This mitigation system was revised in July 2002 to a fixed cap of $250/MWh, effective October 2002.

The base case forecast does not include a wholesale price cap. Instead, peak period prices are determined by a load curtailment price curve ranging from $500 to $1600 per megawatt-hour (year 2000 dollars). In practice, forecast prices rarely exceed $550 per megawatt-hour.

A $250 fixed price cap in AURORA™ will undercut the load curtailment blocks and most of demand response blocks. This will lower peak period prices and reduce the development of generation to meet peak period loads. Increased frequency of unserved load and reduced reserves will result.

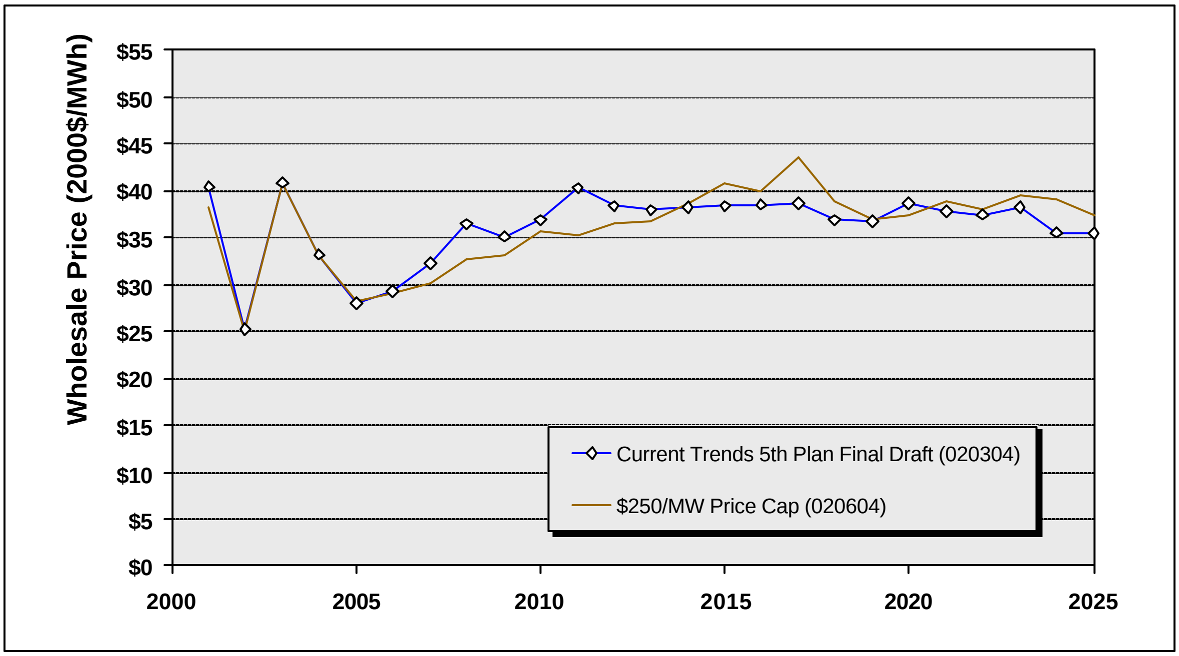
The effect of extending the current FERC price cap through the forecast period on WECC resource development is shown in Figure 17. The overall effect, as expected, is to surpress resource development. New combined-cycle plants are the only resource seeing a net reduction in capacity over the long-term. Approximately 18,000 fewer megawatts of new combined-cycle capacity are in place by the end of the study period in this case. Teh development of new coal is initially deferred, but by the end of the period a net increase of 2000 megawatts is observed. The development of wind is advanced in time and a net of nearly 6000 megawatts of new and existing gas peaking capacity is in service in 2025.

Figure 17: Changes in WECC resource development with $250/MWh price cap



The effect of a continued price cap on forecast prices is shown in Figure 18. Forecast prices ramp op much more slowly in the mid-term because of constrained peak period prices. Because prices in the long-term are slightly higher, the effect is to lower the levelized price forecast only slightly, by $0.30 to $36.30/MWh.

Figure 18: Sensitivity of Mid-Columbia price to a $250/MWh price cap



Planning Reserves

This 15 percent planning reserve analysis was not complete at the writing of this paper.

SUMMARY OF CASE RESULTS

A summary of selected results of the base and sensitivity cases is provided in Table 3. Except for the Mid-Columbia cost and Northwest reserve margin, all values are for WECC as a whole.

Table 3: Summary of base and sensitivity case results

Case	Levelized Mid-Columbia Wholesale Price ($/MWh)	Coal use (2004 - 25) (TBtu)	Gas use (2004 - 25) (TBtu)-	2025 Penetration of Intermittent Resources (%)	CO2 Prod. (2004-25) (MMT)	Ave WECC Reserve Margin (2016-25) (%)	Ave PNW Reserve Margin (2016-25) (%)
Current Trends (Base Case)	$36.60	71,550	42,243	18%	10,095	7.5%	18.2%
Low fuel price forecast	$36.50 (0%)	63,552 (-11%)	48,236 (+14%)	19%	9589 (-5%)	8.0%	n/avail
High fuel price forecast	$33.40 (-9%)	71,437 (0%)	36,295 (-14%)	21%	9735 (-4%)	8.2%	n/avail
Medium-low demand forecast	$35.40 (-3%)	65,045 (-9%)	34,233 (-19%)	22%	8937 (-11%)	n/avail	n/avail
Medium-high demand forecast	$36.60 (0%)	76,062 (+6%)	49,235 (+17%)	19%	10,983 (+9%)	n/avail	n/avail
$250 WECC Price cap	$35.90 (-2%)	73,602 (+3%)	39,772 (-6%)	20%	10,172 (1%)	4.3%	23%
$0.87/T CO2 offset, WA & OR only	$34.10 (-7%)	79,288 (+11%)	36,131 (-15%)	20%	10,556 (+5%)	7.2%	20.2%
Climate Stewardship Act	n/avail	n/avail	n/avail	n/avail	n/avail	n/avail	n/avail
No demand response	$37.10 (+2%)	72,453 (+1%)	41,086)-3%)	20%	10,124 (0%)	n/avail	n/avail
Production tax credit not extended	$37.30 (2%)	73,984 (+3%)	41,776 (-1%)	16%	10,326 (+2%)	8.1%	n/avail

APPENDIX A

FORECAST ANNUAL AVERAGE POWER PRICES FOR NORTHWEST LOAD-RESOURCE AREAS ($/MWh)

Year	West of Cascades	Mid-Columbia	S. Idaho	E. Montana
2004	33.78	33.24	32.66	31.92
2005	28.60	28.05	27.54	26.73
2006	29.91	29.35	28.99	28.10
2007	32.73	32.35	32.29	30.86
2008	36.78	36.42	36.83	35.01
2009	35.48	35.09	34.27	33.42
2010	37.31	36.88	35.52	34.86
2011	40.73	40.29	39.27	38.20
2012	38.87	38.41	37.49	35.90
2013	38.41	38.02	36.80	35.18
2014	38.77	38.29	36.87	34.43
2015	38.80	38.44	38.18	34.37
2016	38.83	38.48	38.85	34.21
2017	38.97	38.67	38.85	34.51
2018	37.17	36.88	36.41	32.74
2019	37.00	36.72	36.01	32.68
2020	38.99	38.69	38.95	34.70
2021	38.14	37.78	37.50	33.57
2022	37.83	37.44	37.19	33.11
2023	38.68	38.27	37.86	34.21
2024	36.14	35.59	34.86	31.78
2025	35.94	35.43	35.59	31.73

APPENDIX B

BASE YEAR LOADS AND FORECAST LOAD GROWTH RATES FOR THE WECC LOAD-RESOURCE AREAS

	Base (Year 2000) Load (Average Megawatts)	**Average Annual Load Growth, 2000-2025**
PNW Eastern WA & OR, Northern ID & Western MT	5901	0.1%
Northern CA	13111	1.4%
Southern CA	17451	1.6%
BC	7324	1.3%
PNW Southern ID	2377	1.1%
PNW Eastern MT	808	0.3%
WY	1764	0.6%
CO	5451	2.2%
NM	2755	2.9%
AZ	7706	2.4%
UT	2938	2.7%
Northern NV	1173	2.0%
Alberta	5824	1.5%
Baja California Norte	1015	2.5%
Southern NV	2340	2.6%
PNW Western WA & OR	13219	0.7%
Total	91158	1.6%

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