CHAPTER III. FORECASTS

Since the April 2003 Least Cost Plan was submitted, PSE has made numerous and significant changes to its long-term forecasting, discussed below. First, the load forecast has been updated to reflect a reduction in both energy and peak capacity. Second, the gas-price forecast has been improved with the consideration of a range of forecasts and scenarios. Third, the long-run Aurora optimization modeling was updated with these load- and gas-price forecasts, along with new assumptions about new plant-financing costs.

A. Energy-Load Forecasts

Electric-Load Forecasts

PSE's policy is to continually update its forecasts based on the latest available information. To that end, the April 2003 Least Cost Plan's forecasts of energy sales and peak loads for electricity have been revised for the August 2003 LCP Update. Similar revisions and updates will continue until a final forecast is produced in fall 2003. Hence the forecast used for the August 2003 LCP Update should be considered an interim forecast.

For the August 2003 LCP update, the billed-sales forecasts for electricity were revised for the following inputs:

- forecasts of regional population and employment, which call for slower growth and a longer recovery period;
- forecast of retail electric rates to account for expected rate changes stemming from changes in the BPA residential-exchange credit, from anticipated power-cost and purchased-gas adjustments, and from a new, long-term rate projection of retail electric rates for the region; and finally
- Calibration of the billed-sales forecasts to account for actual, weather-adjusted billed sales this year.

Economic and Demographic Assumptions

Because the Northwest economy is closely linked to the national economy, PSE forecasts of service-area population and employment are affected by the performance of the national economy. Global Insight (formerly DRI-WEFA) has revised its short- and long-term outlooks of the national economy to account for the most current information. The latest national economic forecast is based on Global Insight's March 2003 25-Year Macroeconomic Forecasts. Based on the new outlook for the national economy, Dick Conway and Associates also has updated PSE's electric-service-territory forecasts for employment and population. Conway's forecast of regional employment and population reflects Washington state's latest benchmarked employment data (for 2002), as well as revised county-population data from the U.S. Census Bureau. Exhibits III-1 and III-2 provide comparisons of the national and regional economic forecasts used in the April 2003 LCP and the August 2003 LCP Update.

Exhibit III-1
National Economic Outlook

	2004	2005	2010	2015	2020	aarg
April LCP						
GDP (BILS. $96)	$ 10,280.1	$ 10,569.3	$ 12,300.0	$ 14,450.8	$ 16,895.1	3.2%
EMPLOYMENT (MILL.)	136.5	138.4	146.4	154.8	161.9	1.1%
POPULATION (MILL.)	283.6	285.9	297.7	310.1	322.7	0.8%
August LCP Update						
GDP (BILS. $96)	$ 10,060.7	$ 10,390.0	$ 12,149.8	$ 14,163.9	$ 16,239.7	3.0%
EMPLOYMENT (MILL.)	133.0	135.4	144.6	153.3	160.8	1.2%
POPULATION (MILL.)	294.2	296.8	309.3	322.0	334.7	0.8%

Compared to the previous forecast, the new outlook calls for a slightly slower growth rate in national economic output, but a slightly higher growth rate in employment. This is driven by an assumption of a slightly lower growth rate in productivity, and a slightly lower inflation rate coupled with stimulative fiscal and monetary policies. Lower personal and corporate income-tax rates and a monetary policy that ensures stable growth in credit are expected to continue to ensure that the national economy recovers from a slow growth mode.

Exhibit III-2
Electric Service-Area Economic Growth Assumptions

	2004	2005	2010	2015	2020	aarg
April LCP						
EMPLOYMENT (THOUS.)	1,757.9	1,795.8	1,972.9	2,124.2	2,277.2	1.6%
POPULATION (THOUS.)	3,402.2	3,438.7	3,659.1	3,859.5	4,078.9	1.1%
August LCP Update						
EMPLOYMENT (THOUS.)	1,718.3	1,749.9	1,924.8	2,066.8	2,203.6	1.6%
POPULATION (THOUS.)	3,419.3	3,450.2	3,636.3	3,805.9	3,980.4	1.0%

While the expected growth *rates* in employment and population are the same in both the August 2003 LCP Update and the April 2003 LCP, the actual levels are not the same. Employment is lower in the August LCP Update, primarily because of a deeper employment reduction in 2002 and a slower recovery in 2003. As a result, the employment peaks experienced by the region in 2000 are not expected to be reached again until late 2005 or early 2006. Population is higher initially, however, because of higher revised final estimates for 2000 from the Census Bureau. In the long run, population growth is expected to be lower than previously forecasted because of slower economic growth. Hence, population totals in the long run are also lower.

Retail Energy-Price Assumptions

This interim forecast also revises PSE's retail electric-price forecast assumptions to account in the near term for an expected reduction in the BPA residential-exchange credit between October 2003 and October 2006, and expected rate adjustments due to increases in power and natural-gas costs. The August 2003 LCP Update also accounts for the long-term changes in Global Insight's forecast of retail electric rates for the entire region. These changes imply an overall increase in retail rates for all customer classes, both in the short and long term.

The retail-rates forecast in the April 2003 LCP assumed no changes in rates in the near term and growth rates of less than 2% per year in the long term. Near term (2004-2005), the August 2003 forecast of residential electric rates is higher by about 5%-10% because of the lower BPA residential-exchange credit, while commercial and industrial electric rates are higher by 1%-5% compared to the near-term forecast of rates in the April 2003 LCP. Longer term (beyond 2006), the new forecast projects PSE electric rates to grow by about 3% per year, while the April LCP forecast predicted a growth rate of about 2.5%. This change arises from a higher forecast of gas prices in the new forecast. The newly updated retail-rate forecasts are preliminary and are based on current information. These forecasts are likely to change again, over time, as the forecasted price of gas changes and as critical decisions are made within the company.

Changes in Other Assumptions

- **New Normal Annual Heating or Cooling Degree Days** – Because the definition of normal heating or cooling degree days is the average of degree days over the most recent 30 years, degree days in 2002 were added to the August 2003 LCP Update calculations while degree days from 1972 were deleted. Since 2002 was slightly warmer than 1972, the new figure for normal annual heating degree-days is slightly lower (4852 vs. 4858). This also implies slightly lower normalized loads.

- **Adjustment in Annual Savings for Ramp-Up and Conversion from Delivered to Billed Savings** – First-year annual savings were adjusted to allow for ramp-up. The effect is that only about half of the targeted savings in the first year is actually realized when a ramp-up based on historical data is imposed. Further, the delivered savings are converted to billed savings by assuming that approximately half of the delivered savings in the current month plus half of the delivered savings in the previous month are billed savings in the current month.

- **Load Losses** from the closure of a Weyerhaeuser lumber mill and the Miller brewery in Tumwater combined for about 4.5 aMW, near term.

As part of the company's ongoing load-forecast updates, more revisions are anticipated in some of the forecasts of inputs discussed above, along with other inputs such as weather-adjustment coefficients and monthly allocation factors.

Electric Sales and Customer Forecasts

Given the revised inputs, PSE expects billed sales (*without* conservation savings) to grow from 2,233 aMW in 2004 to 2,957 aMW in 2022, a growth rate of approximately 1.6 percent per year over the next 20 years. The billed sales forecast with conservation will use the projected conservation savings identified in Chapter VII. Exhibit III-3 shows the sales forecast by class for the August 2003 LCP Update.

Exhibit III-3

Electric-Sales Forecast by Class in aMW

	2004	2005	2010	2015	2020
August LCP Update without Conservation					
Total	2,232	2,252	2,407	2,628	2,857
Residential	1,113	1,118	1,172	1,289	1,414
Commercial	951	966	1,057	1,155	1,253
Industrial	156	157	163	166	169

The growth pattern is such that the growth rate in the next 10 years is slightly lower than the growth rate in the following 10 years. This is a result of the assumption that retail prices will have slightly higher growth rates in the first 10 years than in the second 10 years. Compared to the April 2003 LCP, these growth rates are slightly lower. Exhibits III-4 provides a comparisons of the total billed-sales forecasts for the April 2003 LCP and the August 2003 LCP Update.

Exhibit III-4

Electric Billed-Sales Forecast Comparison

	2004	2005	2010	2015	2020	2022	aarg
April LCP w/o Conserv	2,257	2,291	2,508	2,713	2,936	3,030	1.6%
August LCP Update w/o Conserv	2,232	2,252	2,407	2,628	2,857	2,957	1.6%

The August 2003 LCP forecasts are about 2.9% lower than in the April 2003 LCP, on average, over the next 20 years. The differences in the next two years are less than 1.5%, however, because the changes in employment are not magnified until a few years later, and because of the lag effect (about a year or more) of price changes on consumption.

Electric Customer Counts (Year-End)

Customer-count forecasts also changed as a result of the changes in inputs. The change is consistent with the revisions in population growth, where the population level in the new forecast is slightly higher than the April LCP forecast in the near term but lower in the long term. For the August 2003 LCP Update, PSE's electric-customer count is expected to grow by about 1.7% per year, compared to 1.8% in the April 2003 LCP forecast. Exhibit III-5 shows a comparison of the April LCP and the August LCP Update forecasts of year-end customer counts.

Exhibit III-5

Electric-Customer Counts (Year-End)

	2004	2005	2010	2015	2020	2022	aarg
April LCP	990,281	1,006,365	1,100,176	1,199,495	1,308,581	1,354,784	1.8%
August Update LCP	994,312	1,011,067	1,100,658	1,197,158	1,299,160	1,342,730	1.7%

Electric Peak-Load Forecasts

Based on further evaluation of the electric peak-load forecast, the peak-load equation was re-calculated using an expanded estimation period. This is expected to make the contribution of non-weather-sensitive loads to peaks more accurate because the data will have more observations where the transportation loads are excluded. The re-calculation further tested for the effects of consecutive cold-snap days, non-linearity in the temperature sensitivity in the extreme cold events, and whether there is a difference between morning versus afternoon/evening peaks. The final form of the re-calculated peak-load equation is as shown below:

Peak MW = a*(Resid aMW) + b*(Non-Resid aMW)
+ c*(Normal Temp for Month – Peak Hour Temp)*(Weather Sensitive aMW)
*Season Dummy
+ d*(Sched 48 Dummy) + e*(El Niño Dummy + f*(2-Day Consec Cold Snap)

- a, b, c, d, e, and f are coefficients to be estimated
- Resid aMW – residential delivered sales in the month
- Non-Resid aMW – commercial + industrial delivered sales in the month
- Weather Sensitive aMW – residential + 80% of commercial delivered sales
- Season Dummy – equals 1 if season is winter, zero otherwise; same for summer and shoulder months
- Sched 48 Dummy – equals 1 if year is 2001 and beyond
- El Niño Dummy – equals 1 if month is identified as El Niño month based on NOAA data

The only difference between this equation and the equation used in the April 2003 LCP is the addition of the 2-Day Consecutive Cold-Snap variable. This variable is a binary variable that equals 1 if the month's peak load is preceded by two consecutive cold-snap days in which peak loads exceeded 4,000 MWs. One-day and three-day consecutive cold days also were examined, but only the two-day consecutive cold days showed a statistically significant coefficient. Further, non-linearity in temperature sensitivity in the extreme cold events and introduction of a binary variable that distinguishes morning versus afternoon or early evening peaks were tested, but both tests resulted in non-statistically significant coefficients. Finally, this equation was estimated using data from January 1991 to March 2003, compared to the April 2003 LCP equation, which used data from January 1991 to December 2001. The re-estimation lowered the coefficient associated with non-residential loads, which was expected because there were more observations (from January 2002 to March 2003) in which the non-residential load was free of the transportation loads. There was only a gradual reduction of the transportation loads in 2001.

The table below provides a comparison of the estimated coefficients between the April 2003 LCP forecast and the August 2003 LCP Update forecast for the winter season-only case.

Exhibit III-6

Coefficients for Peak-Load Equations, Winter Case

Estimated Parameter	April LCP Equation	August LCP Equation
a	2.1590	2.2250
b	1.1520	0.9370
c	0.0212	0.0196
d	-0.2370	-0.2240
e	-122.0400	-185.1220
f		229.1160
RSqr	0.962	0.964

All the estimated parameters shown above are also statistically significant. Using the updated equation, the August 2003 LCP Update provides a forecast of normal January peak-hour load based on the following assumptions: 23 degrees Fahrenheit; a new forecast of sales; no El Niño; and a frequency of 2-day consecutive cold snaps matching the historical average of .04. The exhibits below show comparisons of the peak-load forecasts contained in the April 2003 LCP and the August 2003 Update.

Exhibit III-7

Electric-Peak Forecasts in MWs

	2004	2005	2010	2015	2020	2022	aarg
Normal Peak Load Without Conservation							
April LCP	4,874	4,942	5,409	5,853	6,333	6,535	1.6%
August LCP Update	4,508	4,538	4,785	5,250	5,734	5,948	1.6%

The average difference in forecasts between the April 2003 LCP and the August 2003 LCP Update is about 10% over the 20-year forecast period. The reduction in peaks is due to a lower projection of residential and non-residential loads, and a smaller projected contribution of non-residential loads to peaks based on the re-estimated equation.

Gas Load Forecasts

Gas-load forecasts generally are updated each fall and thus are not part of the August 2003 LCP Update. Nevertheless, the next gas-sales forecast, when completed, is expected to be somewhat lower than the April 2003 LCP forecast because of long-term projections for lower employment levels and lower population growth, and for higher retail gas rates stemming from increased gas costs.

B. Gas Price Forecast

Original Forecast – April 2003 Least Cost Plan

In its April 2003 Least Cost Plan, PSE used the gas-price forecast from the PIRA Energy Group (PIRA), an international energy-consulting firm offering data, analysis, and forecasting on international oil, natural gas, and electricity markets. The PIRA forecast selected was the fall 2002 long-range forecast for individual supply basins in the Western regions of the U.S. and Canada. The PIRA forecast provided annual natural gas prices for selected years through 2015. Because annual price forecasts over a 20-year planning horizon were required for PSE's Least Cost Plan, PSE developed a straight-line curve for interpolating the missing years from the PIRA forecast and projecting annual prices to 2023.

Revised Forecast – August 2003 Update

In anticipation of the August 2003 Least Cost Plan Update, PSE determined that a review of the PIRA gas-price forecast was warranted in light of the gas market's volatility in early 2003, which resulted in a significant run-up in near-term gas prices. Growing concern in the industry regarding an imbalance in supply and demand suggested that near-term prices would stay relatively high until equilibrium in the markets was re-established. In addition, the PIRA forecast results were low relative to other gas-price forecasts in the region, notably the "Medium" gas-price forecast of the Northwest Power and Conservation Council (NPCC).

Upon reviewing additional PIRA gas-price data (including previously missing years), the underlying assumptions regarding the availability of new resources at certain high gas-price points resulted in a return to lower-equilibrium price levels. These lower price levels reflect the cyclical pricing from boom-and-bust gas-supply development (as opposed to the smooth price curve previously developed from the data). Revised annual gas-price projections were developed ("PIRA-Revisited" forecast) using the cyclical pattern from new PIRA data, including the outer years of the planning period (2015 to 2023).

PSE then acquired access to Cambridge Energy Research Associates' (CERA) December 2002 long-range gas-price scenarios for North America, provided under CERA's North American Gas and Power Advisory Service. CERA's long-term, regionally specific price scenarios provide average annual market prices by supply basin or trading hub through the year 2020. PSE extended the CERA data from 2020 to 2023 based on the average annual gas-price change from 2006-2020. The four available CERA supply/price scenarios were reviewed for applicability based on the underlying economic and supply-development assumptions of each scenario. CERA's four scenarios are described as follows:

- **Rear-View Mirror** - The economy recovers from the recession in late –2002(3?), but economic uncertainty remains, and a crisis of confidence emerges.
- **Technology Enhanced** - The recession proves to be mild and short-lived, and the North American economies return to a sustained period of economic growth as new technological developments abound.
- **World in Turmoil** - The current recession is not a short detour. Instead, the North American economy mirrors the recent performance of the Japanese economy.
- **Shades of Green** - The economy recovers steadily and the environment becomes an increasing concern. Some international agreements are reached to control greenhouse-gas emissions.

Two scenarios, World in Turmoil and Technology Enhanced (including their associated supply- and infrastructure-development assumptions) were judged the most apt descriptors of the range of economics in the western U.S. markets affecting PSE. [RT: this judgment seems contradictory – one scenario says the economy improves soon, the other says we're in for a prolonged slump] In particular, these two scenarios anticipate more aggressive development of new resources in the Western Canadian Sedimentary Basin of Alberta and British Columbia, and the emergence of gas supplies from the McKenzie Delta prior to the end of the decade.
Rather than relying on a single forecast or scenario to predict long-term gas prices, PSE elected to average four of the known forecasts used in the region, including the two previously mentioned CERA scenarios. The four forecasts are:

- NPCC Medium Gas Price Forecast
- PIRA "Revisited" (including cyclical shaping data)
- CERA - World in Turmoil Scenario
- CERA - Technology Enhanced Scenario

While the average of the four gas-price scenarios provided an adequate representation of long-term regional gas prices based on objective, independent research and analysis, PSE determined that none of the four scenarios (or their average) adequately considered the recent run-up in market prices. Such consideration would have shown a more profound price impact on near-term resource planning. Therefore, the forecasted gas-price results for 2004 were replaced with currently available market-price quotes from June 2003.

In order to consider the impacts of extremes in gas pricing, PSE chose a High Price forecast (defined as the NPCC Medium Price Forecast) and a Low Price forecast (defined as the PIRA straight-line forecast used as the base-case forecast in the April 30, 2003, LCP analyses).

The four forecast scenarios, the resulting average of the four, and the adopted High and Low price strip for the three main trading hubs affecting PSE's supply costs are depicted in Exhibits III-8 to III-10:

Exhibit III-8
Sumas Gas Price ($/Dth)

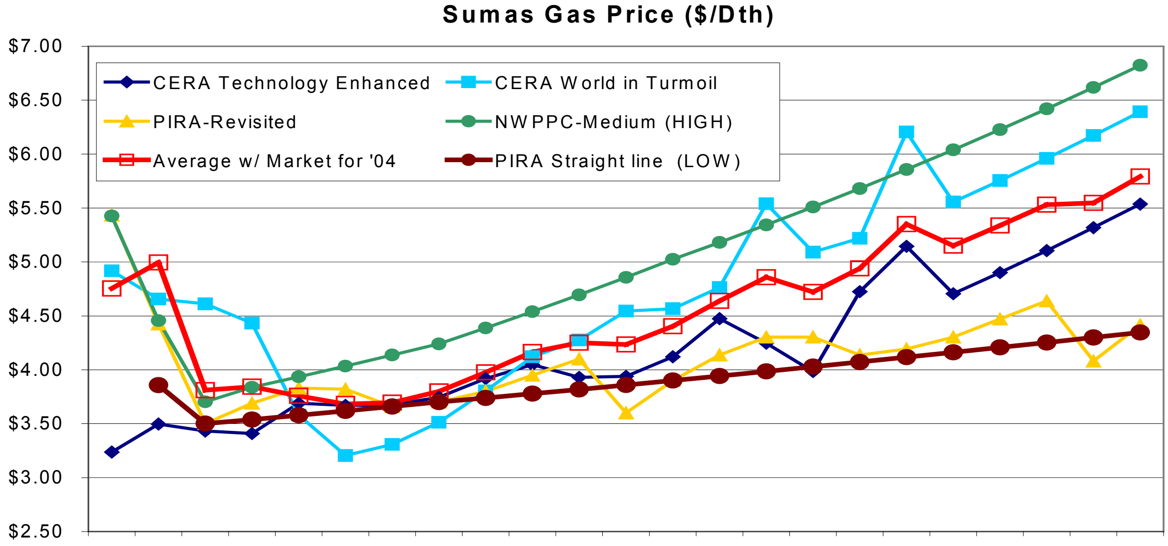


Exhibit III-9

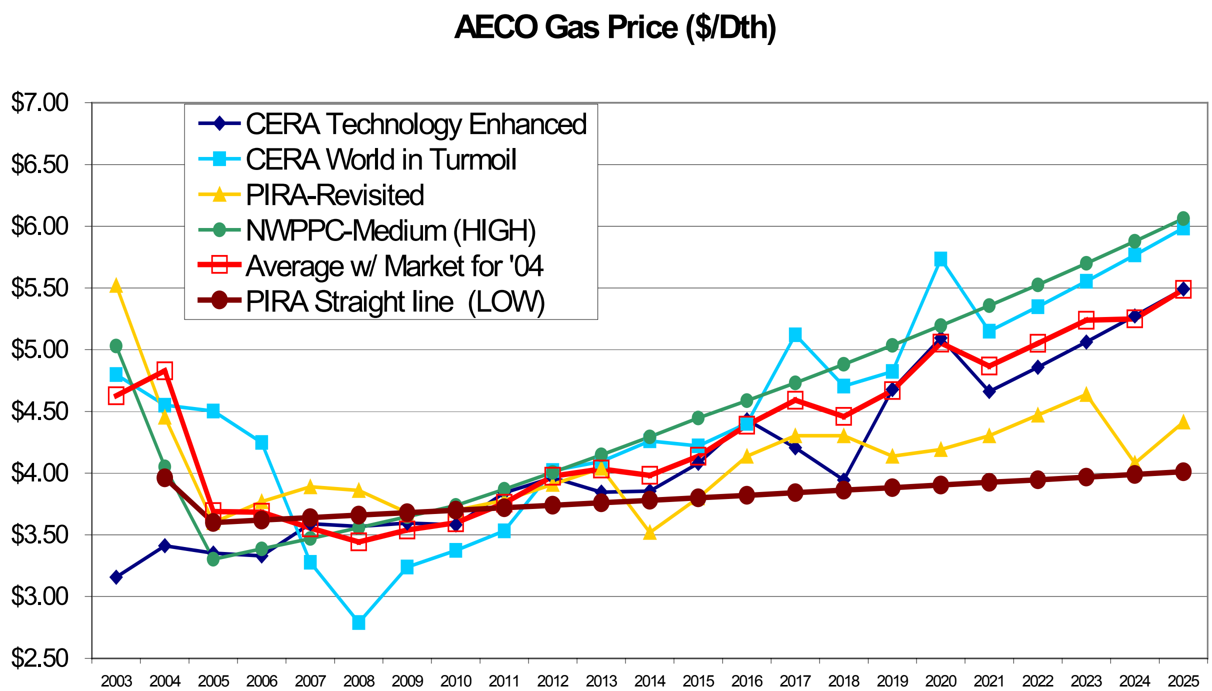
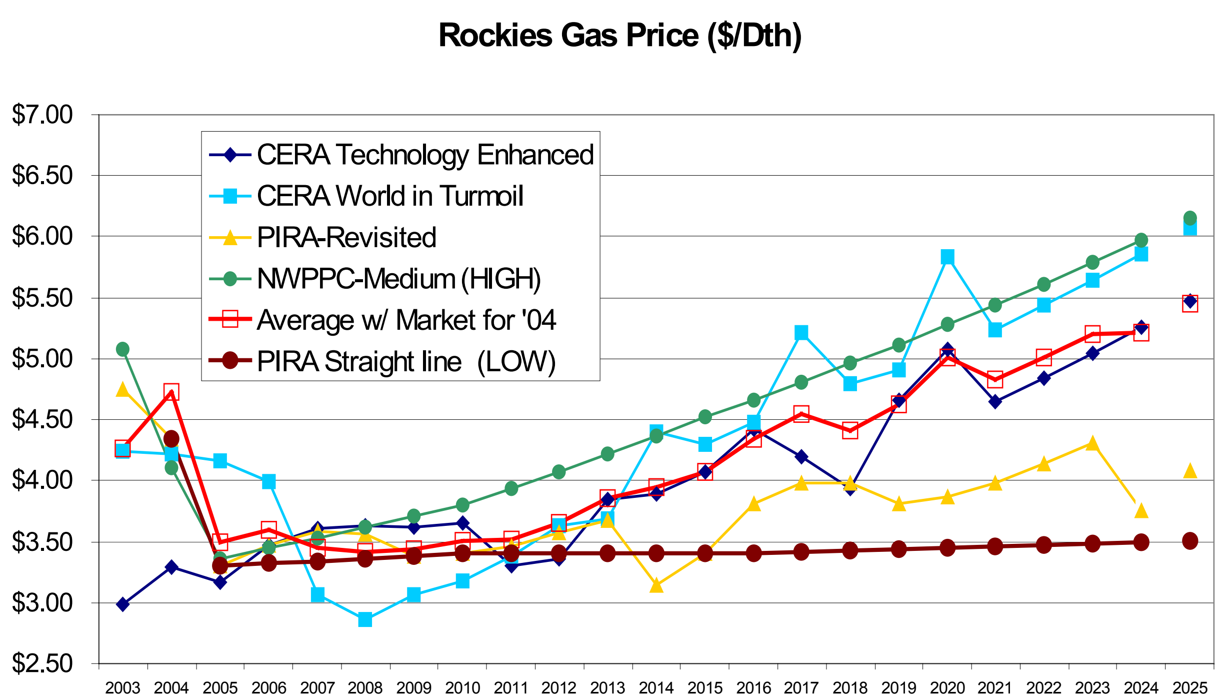


Exhibit III-10



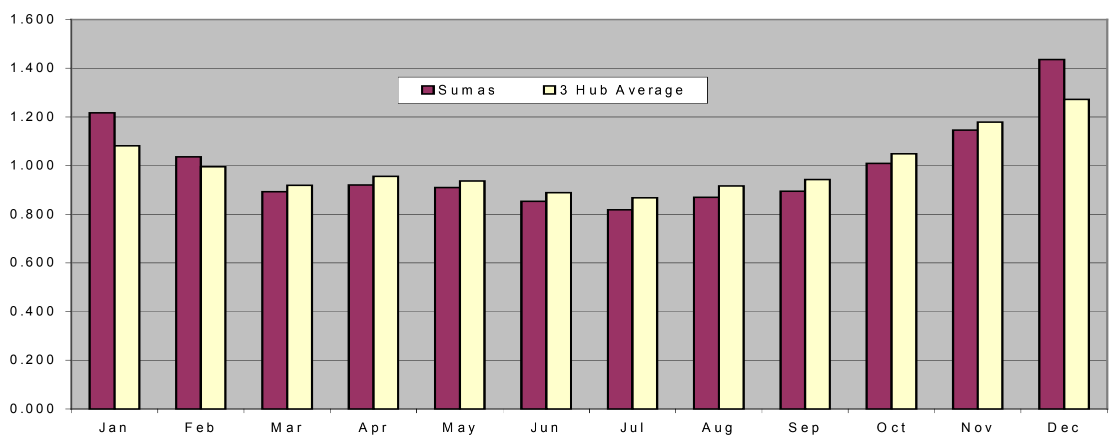
C. AURORA Assumptions

Gas Prices

As discussed previously, PSE considered a number of gas-price forecast scenarios and sources including PIRA, CERA, and the NPCC. Each annual price requires that a monthly shape factor be applied to generate 12 monthly prices. The monthly shape factors are the average of the three Northwest hubs – Sumas, AECO, and Rockies – for the years 1991-1999. More recent data do not have any consistent pattern and the prices show extreme volatility and randomness.

Exhibit III-11 illustrates the traditional pattern of higher prices in the winter and lower prices in the summer. The three-hub average was applied to all eight hubs in the model other than Henry Hub, which has its own monthly shaping.

Exhibit III-11
Monthly Shaping



Electricity Demand

AURORA divides the WECC into 13 subregions with individual growth rates. Exhibit III-12 lists the regions along with the long-run regional growth rates. The growth rates were adopted from the NPCC, “Draft Forecast of Electricity Demand of the 5th Pacific Northwest Conservation and Electric Power Plan,” August 2, 2002. Short-run demand was adjusted downward to take into account the current recession, following the assumptions in the NPCC’s 5th Draft of Wholesale

Electric Price Forecast. Intermediate-term growth rates were increased so that the long-run growth rate was unchanged.

Exhibit III-12
Regional Demand

Region	Annual Increase (%)
OR / WA / No. ID	1.50
No. California	1.71
So. California	1.87
British Columbia	1.53
Idaho South	1.71
Montana	0.90
Wyoming	0.23
Colorado	1.22
New Mexico	2.43
Arizona / So. Nevada	1.39
Utah	2.32
No. Nevada	1.65
Alberta	1.53

New Northwest Resources

In 2002 there were over 8,000 MW of new resources under development. Most of the proposed projects, however, did not make it beyond the planning stage. PSE currently assumes that 2,055 MW of new natural gas-fired resources will be available in the region. Presently four plants have been completed, with two under construction to be on line by mid-2004. Exhibit III-13 lists those plants.

Exhibit III-13
New Natural Gas-Fired Resources

Plant	Owner/Developer	Capacity MW)	Online Date
Coyote Springs II	Avista-Mirant	260	Online
Hermiston	Calpine	530	Online
Goldendale	Calpine	248	Q2/04
Big Hanaford	TransAlta	248	Online
Frederickson I	EPCOR	249	Online
Chehalis	Tractebel	520	Q3/03

Other well-known gas-fired resources that once were expected to be developed, such as the Duke Grays Harbor plant, have not been assumed into the model. Wind resources that could be built in 2003, or later, were not assumed to be built. The AURORA database includes 473 MW of wind generation, which their developers listed as going on line in 2002.

New California and Arizona Resources

Demand from California has a significant impact on Northwest energy prices during the summer peak, hence an accurate representation of the resources serving California was included in the model. Significant resources, primarily natural gas combined-cycle and simple-cycle plants, have been completed recently in California and Arizona. The database in AURORA has been updated with information provided by Henwood Consulting, dated 4/29/03. Plants added to the database include those listed as “completed” and those “under construction,” with on-line dates in 2003. For California and Arizona together the data set includes 33 new plants of approximately 10,000 MW total capacity.

Known plant retirements were also taken into account. The California ISO published a list of plants which have been recently retired or have a retirement date reported to the California ISO. These plants total approximately 2,500 MW for California and Arizona for the period 2004-2006.

New AURORA Resources

A key driver in the AURORA model is the expected return on capital invested in new generation assets for the Western Power Market. This expected return is derived through estimates of the future developer mix, the developers’ respective capital structures, and their average cost of equity and debt over the forecast period.

AURORA requires an input assumption regarding who will develop future plants in the region. PSE has assumed that these plants will be developed by publicly owned utilities (Public), investor-owned utilities (IOUs), independent power producers (IPPs), or independent power producers with power purchase agreement(s) in place with an IOU (IPP/IOU). PSE’s assumption for the relative contribution from each developer type is outlined in Exhibit III-14.

Exhibit III-14
Developer Mix

Asset Type	Public	IOUs	IPPs	IPP/IOU
CCCT	20%	30%	20%	30%
SCCT	20%	30%	20%	30%
Wind	20%	30%	20%	30%
Coal	20%	35%	10%	35%

These allocations are reasonable estimates for future developer mix and assume that in the near-term, continued weakness in the IPP credit market will require IOUs to self-build to meet load-growth demands. Additionally, as credit markets recover, financing will be easier for IPPs that have signed long-term PPAs with credit-worthy counterparties, such as IOUs. Pure merchant IPPs will still be present in the market, but their market share of new projects is expected to be far smaller than previously experienced. This approach is consistent with Navigant Consulting, Inc.'s view of the future development of the Western Power Market.

The capital structure for these four developer types is identified in Exhibit III-15. Capital structure for the IPP/IOU developer has been estimated at 70/30 debt/equity, and reflects the potential for increased leverage on projects with credit-worthy counterparties.

Exhibit III-15
Capital Structure

Asset Type	Public	IOUs	IPPs	IPP/IOU
Debt	100%	55%	50%	70%
Equity	0%	45%	50%	30%

The cost of capital for these four developer types is identified in Exhibit III-16. The expected returns on debt and equity for IPP/IOU developers have been estimated at 7.5 percent and 17 percent respectively, and appear valid given the returns identified for other developers. The cost of debt at 7.5 percent mirrors that of an IOU and is based on the assumption that the ultimate counterparty risk lies with the power purchaser or IOU. However, the equity return for an IPP/IOU would not be expected to match that of an IOU, since the risk profile for an IOU investor will differ from that of an IPP/IOU investor. In addition, IPP/IOU investors are likely to demand a higher rate of return to offset the greater risk associated with a highly leveraged investment.

Exhibit III-16
Cost of Capital

Asset Type	Public	IOUs	IPPs	IPP/IOU
Debt	6.5%	7.5%	8.7%	7.5%
Equity	0%	11.5%	20%	17%

Timing and Limits of New Resource Development

In AURORA, new plants are brought online at the optimal time without regard to planning horizons. To replicate realistic planning needs, certain limits need to be placed on the rate of development on the various technologies for the 20-year analysis. Coal plants were excluded from development in the Washington/Oregon area and limited to one plant in the northern and southern California areas. Coal plants require a long development time, so they likely could come online in California in 2010 and in 2007 in other areas. Wind was restricted to one new plant per year in each region, and could be developed immediately. Natural gas-fired combined-cycle and simple-cycle turbines also have quick development times and required no limitations.

Cost of Various Technologies

The AURORA model selects new resources for addition from a set of generic resources that will result in lowest overall cost. The cost and performance characteristics were provided by Tenaska for the combined-cycle and simple-cycle gas plants, as well as the coal plant. The wind data were provided by Navigant Consulting, Inc. and confirmed by other sources, while the solar data are from the NPCC.

The capacity of most new generation resources (i.e., the capacity of individual projects in MWs) can be scaled to meet the specific needs of the developer, hence there is not one correct size or correct cost estimate for each technology. Furthermore, with shared ownership, even greater flexibility of capacity can be achieved for a utility. PSE, in collaboration with Tenaska, selected a representative plant for each gas and coal technology based both on economies of scale and on current development practices. Exhibit III-17 provides a list of the primary characteristics.

Exhibit III-17

Cost and Performance Characteristics

Technology	Capacity (mw)	Heat Rate (btu/kwh)	All-In Cost ($/kw)	Fixed O&M ($/kw)	Fixed Fuel ($/kw)	Variable O&M ($/mwh)
CCCT	516	6,900	710	11.00	15.55	2.00
SCCT	168	11,700	441	3.00	15.74	2.00
Coal	900	9,425	1,500	20.0	0	2.00
Wind	100	0	1,003	26.10	0	0
Solar	20	0	6,000	15.00	0	0.80

The CCCT represents a two-by-one configuration – two turbines with a heat-recovery system. These plants typically are scaled by increments of about 250 MW, with variations around those figures depending on specific configurations. The $710/KW all-in cost is based on an analysis of PSE's Frederickson site.

The SCCT represents a lower-cost traditional peak using "frame" FA or EA gas turbines in simple cycle. More expensive aero-derivative plants are available that have a better heat rate at a much higher cost. Throughout the industry and its literature, one can find a wide variety of capacities, heat rates, and costs for the numerous simple-cycle options. The least-cost option is site- and application-dependent. The costs provided by Tenaska are based on the same assumptions as the combined-cycle and coal plants, which allows for a fair comparison between the technologies. For example, the listed SCCT starts with an EPC cost (engineering, procurement and construction) of $327/kw before taking into account "soft" costs such as insurance, contingencies, and costs related to financing, start-up, spares, etc., before arriving at a total installed-capacity cost of $441/kW.

The coal plant represents a new site with a supercritical boiler design. An alternative would be a plant with 2 percent to 4 percent lower costs but with a 2 percent to 4 percent higher heat rate. Again, the least-cost option depends upon the site and application.

The wind plant is based on the assumption that 100 MW is necessary to achieve economies of scale.

Improved Efficiency

Over time the heat rate of the various thermal plants is expected to improve. Starting with the heat rates listed above, PSE adopted the performance improvements provided by the Energy Information Administration in the "Annual Energy Outlook 2003." Through 2010, coal-plant performance improves by 0.4 percent per year, combined-cycle performance improves by 1.1 percent per year, and simple-cycle performance improves by 0.6 percent per year. After 2010, improvements are assumed to be quite small (0.2 percent) or zero in the later years.