Demand Forecast

INTRODUCTION AND SUMMARY

A 20-year forecast of electricity demand is a required component of the Council's Northwest Regional Conservation and Electric Power Plan.[1] Understanding growth in electricity demand is, of course, crucial to determining the need for new electricity resources and helping assess conservation opportunities. The Council has also had a tradition of acknowledging the uncertainty of any forecast of electricity demand and developing ways to reduce the risk of planning errors that could arise from this and other uncertainties in the planning process.

Electricity demand is forecast to grow from 20,080 average megawatts in 2000 to 25,423 average megawatts by 2025 in the medium forecast. The average annual rate of growth in this forecast is just less than 1 percent per year. This is slower demand growth than forecast in the Council's Fourth Power Plan, which grew at 1.3 percent per year from 1994 to 2015.

The slower demand growth primarily reflects reduced electricity use by the aluminum industry and other electricity intensive industries in the region. Forecasts of higher electricity and natural gas prices will fundamentally challenge energy intensive industries in the region.

The medium case electricity demand forecast means that the region's electricity needs would grow by 5,343 average megawatts by 2025, an average annual increase of 214 average megawatts. As a result of the 2000-01 energy crisis, the 2003 demand is expected to be nearly 2000 average megawatts lower than in 2000, making the annual growth rates and megawatt increases from 2003-2025 higher than from the 2000 base. The annual growth rate from 2003 to 2025 is 1.5 percent per year, with annual megawatt increases averaging 330.

Compared to the 2015 forecast of demand in the Council's Fourth Power Plan, the Fifth Plan forecast is 3,000 average megawatts lower. Nearly, two thirds of this difference is due to lower expectations for the region's aluminum smelters.

The most likely range of demand growth (between the medium-low and medium-high forecasts) is between 0.4 and 1.50 percent per year. However, the low to high forecast range recognizes that growth as low as -0.5 percent per year or as high as 2.4 percent per year is possible, although relatively unlikely. Table A-1 summarizes the forecast range.

[1] Public Law 96-501, Sec. 4(e)(3)(D)

Table A-1: Demand Forecast Range

	(Actual) 2000	2015	2025	Growth Rates 2000-2015	2000-2025
Low	20,080	17,489	17,822	-0.92	-0.48
Medium Low	20,080	19,942	21,934	-0.05	0.35
Medium	20,080	22,105	25,423	0.64	0.95
Medium High	20,080	24,200	29,138	1.25	1.50
High	20,080	27,687	35,897	2.16	2.35

FORECASTING METHODS

The approach to the demand forecasts is significantly different from previous Council plans. For this plan, the Council has not used its Demand Forecasting System. Instead there are three separate approaches to the forecast in terms of methods and relationship to the Council's Fourth Power Plan. The methods differ for (1) the range of long-term non-direct service industry (non-DSI) forecasts from low to high; (2) for a monthly near-term medium case forecast; and (3) for a forecast of aluminum smelter and other direct service industry (DSI) demand.

The non-DSI forecasts generally rely on the forecasts from the Fourth Power Plan for their long-term demand trends. The decision to use the Fourth Power Plan forecast trends was based partly on an assessment of the accuracy of those forecasts over the five or six years since they were done.[2] The total demand forecasts tracked actual loads very closely between 1995 and 2000. The average percentage error in the forecast of electricity consumption for those years has been less than one half of a percent. Figure A-1 illustrates actual consumption compared to the medium, medium-low and medium-high forecasts through 2000. Figure A-1 also illustrates the ability of the model to simulate the period before 1995 when actual values of the main forecast drivers are used.

The forecasts for individual consuming sectors have also been quite accurate since the 1995 forecasts were done. The level of residential consumption was overforecast by an average of 0.6 percent. Commercial consumption was underforecast by an average of 0.9 percent, and industrial consumption, excluding DSIs, was overforecast by an average of 3.6 percent. Since there was little evidence that the long-term forecasts were departing seriously from actual electricity consumption, the Council decided to continue to rely on its earlier forecast trends for non-DSI electricity demand.

The medium case non-DSI forecast is developed in two stages. The first stage is a near-term monthly forecast of demand recovery from the recent energy crisis. The second stage is a long-term forecast of demand trends from 2005 to 2025.

[2] Northwest Power Planning Council. "Economic and Electricity Demand Analysis and Comparison of the Council's 1995 Forecast to Current Data." September 2001, Council Document 2001-23. http://www.nwcouncil.org/library/2001/2001-23.htm

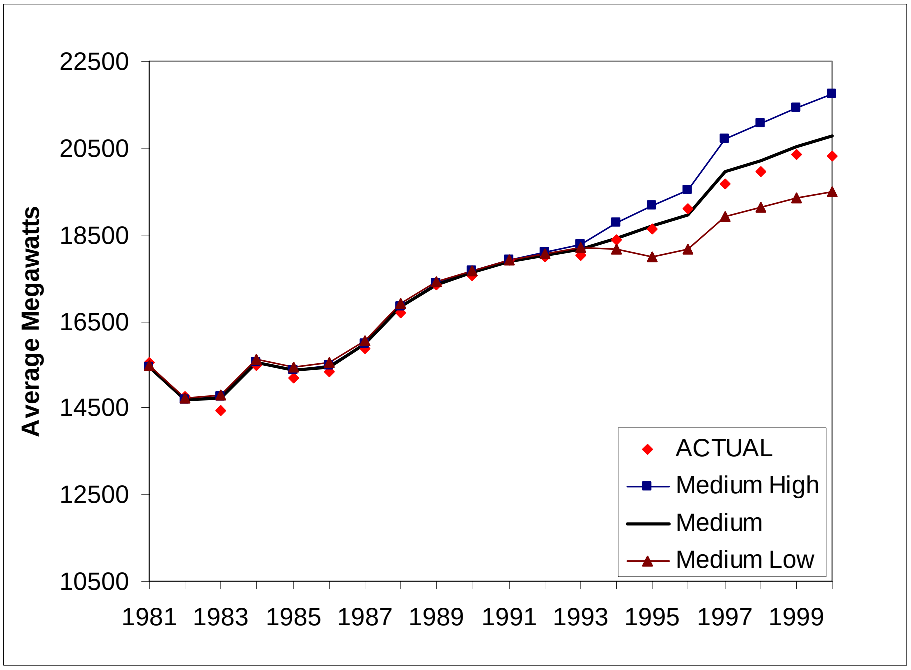


Figure A-1: Demand Forecast Versus Actual Consumption of Electricity

During late 2000 and 2001, electricity demand decreased dramatically in the region due to the electricity crisis, large increases in retail electricity rates, and an economic recession. The Council analyzed the components and causes of the 2000-2001 decline in electricity consumption in its assessment of the outlook for winter 2001-2002 electricity adequacy and reliability.[3] As illustrated in Figure A-2, nearly 60 percent of the reduction was due to closing down aluminum smelters, which make up the bulk of the DSI category. Therefore, a large part of the total medium forecast of demand recovery depends on specific assumptions about the return to operation of aluminum and other large industrial loads that were either bought out or shut down during 2001. The medium case forecast to 2005 addresses the recovery from this starting condition.

The medium case forecast of non-DSI demand recovery depends on assumptions about recovery from the economic recession and the effects of recent retail electricity price increases, although these effects are not modeled in any formal way. In general, the effects of higher retail electricity prices are assumed to dampen the effect of economic recovery on electricity use and slow the recovery of electricity demand. By 2005 non-DSI electricity demands are assumed to have nearly returned to a non-recession level, but that demand is lower than the Fourth Power Plan forecast due to some assumed permanent effects of higher electricity prices, as well as lasting efficiency improvements achieved during the crisis.

[3] Northwest Power Planning Council. "Analysis of Winter 2001-2002 Power Supply Adequacy." November 2001. Council Report 2001-28. http://www.nwcouncil.org/library/2001/2001-28.pdf

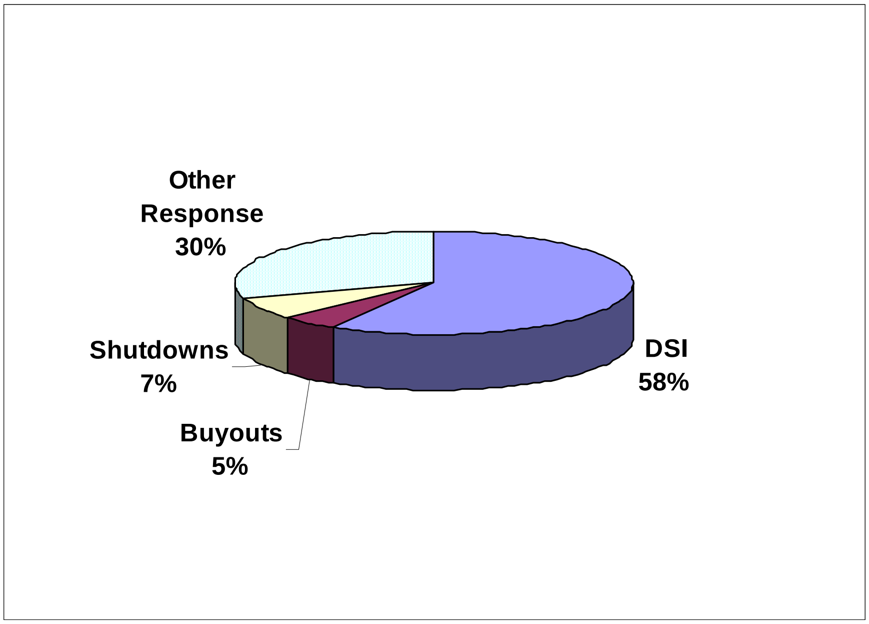


Figure A-2: Components of a 20 Percent Load Reduction From July 2000 to July 2001

The near-term medium forecasts are done on a monthly basis through 2005. The monthly forecasts through 2005 are done as electricity loads to facilitate tracking the forecast against actual load data as it becomes available. After 2005 the forecast is presented as electricity sales and is comparable to the range forecasts and to previous Council demand forecasts.

The range of long-term non-DSI forecasts is developed for the years following 2005. These four forecasts, as well as the medium case extension beyond 2005, depend on the growth rates of the corresponding forecasts in the Fourth Power Plan. The 2005 starting points for the range forecasts are estimated by applying Fourth Plan low to high case growth rates to an estimate of actual electricity demand in 2000 instead of the Fourth Plan forecasts for 2000. However, the relative pattern of growth for each case is adjusted to resemble the pattern of near-term medium case decreases in 2001 and recovery to 2005. After 2005, low to high case annual growth rates from the Fourth Plan were applied to the respective range of cases. This approach results in a narrower range of forecasts than the corresponding years' forecasts in the Fourth Power Plan.

The long-term forecasts should be viewed as estimates of future demand, unreduced for conservation savings beyond what would be induced by consumer responses to price changes. The Council has referred to these forecasts as "price effects" forecasts in the past. The shift from actual consumption to the price effects forecast is made in 2001. In the medium case, the only sector with any significant programmatic conservation by 2001 in the Fourth Power Plan was the residential sector. Residential sector consumption in 2001 has 191 average megawatts of programmatic conservation savings added to demand. This makes the decrease in residential consumption appear smaller in the forecast than actual consumption decreases are likely to be for 2001. Similar adjustments affect the higher growth cases for the other sectors as well.

The forecast of electricity demand by the region's aluminum smelters and the few other remaining industrial plants that were traditionally served directly by the Bonneville Power Administration (DSIs) are discussed separately. The forecast of aluminum smelter electricity use is an exception to reliance on the Fourth Plan forecast trends. Both the method of forecasting and the results are significantly different from the Fourth Power Plan.

DEMAND FORECAST

The medium-term monthly forecasts are presented in the form of monthly "load" forecasts. That is, the values include transmission and distribution losses. The long-term forecasts are presented as electricity sales, or electricity consumption at the end-use level, and therefore exclude transmission and distribution losses. The long-term forecasts of electricity demand are developed for individual consuming sectors such as residential, commercial, and industrial. The long-term forecasts are directly comparable to the demand forecasts presented in the Fourth Power Plan. Detailed tables of annual electricity demand forecasts by sector appear at the end of this appendix.

The forecast of demand for electricity by aluminum smelters is treated separately from the non-DSI demand. This reflects the large amount of electricity required by these plants combined with a growing uncertainty about their future operation in the region.

Non-DSI Forecasts

Near-Term Monthly Non-DSI Load Forecast

Figures 3a and 3b illustrate how the near-term forecasts of non-DSI loads are designed to track recovery back toward the forecast trends from the Council's Fourth Power Plan. In Figure A-3a the upper line is the Fourth Power Plan trend forecast converted to electricity loads with a monthly pattern added. The lower line shows the near-term monthly forecast of loads. The dashed vertical line separates actual monthly load data from the forecast. The recovery may be clearer in the corresponding annual numbers shown in Figure A-3b.

When the Council first developed a near-term forecast of load recovery in October 2001, it was expected that non-DSI loads would recover to near the Fourth Plan forecast levels by 2004. This is no longer the case, as shown in Figures 3a and 3b. There are two substantial reasons for the changes to the near-term load forecast since the earlier assessment. First, the anticipated rate of economic recovery has been slower than expected. Second, energy prices, which fell substantially in 2002, have increased again in 2003. Some of the increase is due to temporary conditions including strikes in the oil industry of Venezuela, concerns about the war in Iraq, a cold winter in the Eastern part of the country, and low runoff forecasts for the Pacific Northwest. However, other contributors to high energy prices may be indicative of longer-term trends. These include the reduced growth in natural gas supplies in spite of significant drilling activity and continued high retail prices for Bonneville's customers and the customers of investor-owned utilities as well.

As shown in Figure A-3b, instead of recovering to the long-term trend forecast from the Fourth Power Plan by 2004, the revised annual non-DSI load forecast remains below the Fourth Plan forecast in 2005. This difference, which amounts to 929 average megawatts, is considered to be a permanent reduction in electricity demand, and affects the long-term forecast as well. The reductions are focused in the industrial sector, where energy intensive businesses are vulnerable to the large price increases the region has suffered since 2001.

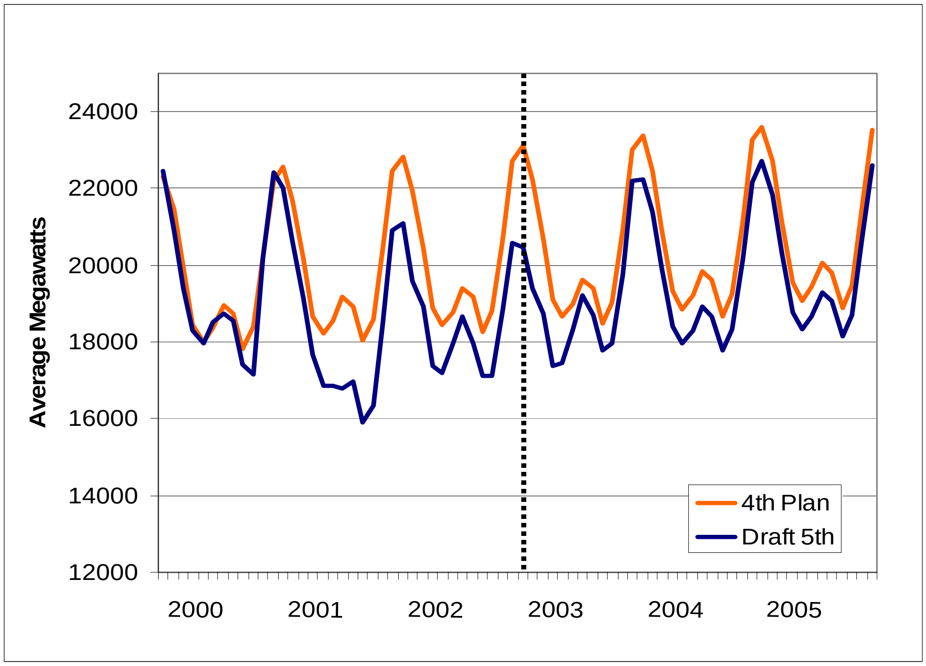


Figure A-3a: Comparison of Monthly Near-Term Forecast to the Fourth Power Plan

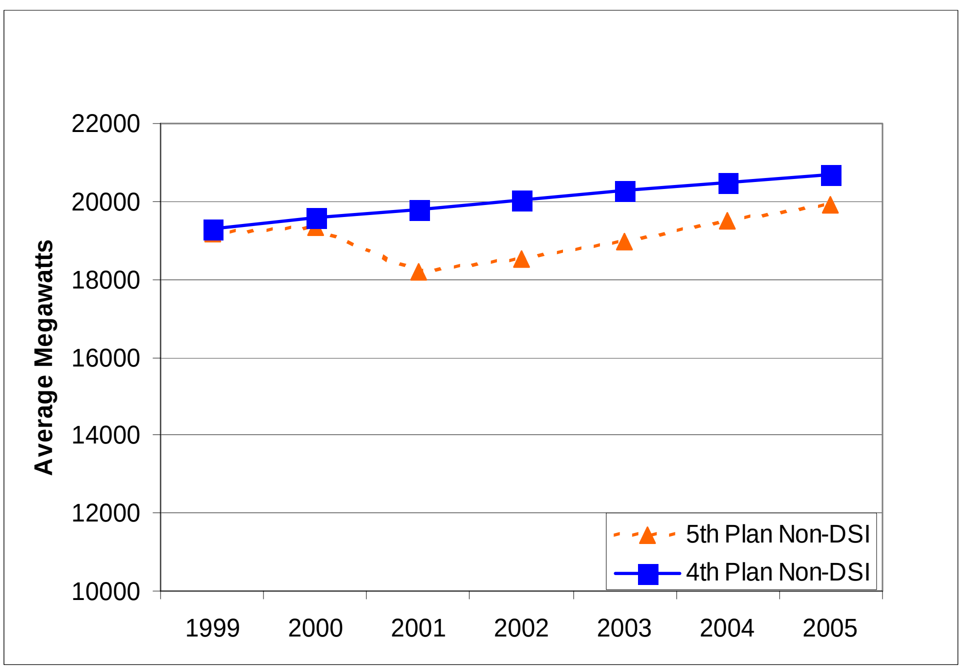


Figure A-3b: Comparison of Annual Near-Term Forecast to the Fourth Power Plan

Long-Term Forecasts of Non-DSI Demand

The range of long-term forecasts of total non-DSI electricity sales is shown in Figure A-4. In the medium forecast, non-DSI electricity consumption grows from 17,603 average megawatts in 2000 to 24,464 average megawatts by 2025. This is an increase of 1.33 percent, and 275 average megawatts, per year from 2000 to 2025. These growth indicators are lowered somewhat by the electricity crisis and recession in 2000-01. From 2005 to 2025 the average annual growth rate is 1.43 percent per year, with an average annual increase in consumption of 300 average megawatts.

Figure A-4 illustrates how the Fourth Plan demand forecast and the near-term and long-term forecasts for the Fifth Power Plan compare. The near-term forecast reflects the currently depressed electricity demand and then merges into the medium forecast. The other forecasts in the range appear as dashed lines that extend from 2005 to 2025. The Fourth Plan forecasts appear as solid lines that extend to 2015. Historical actual weather adjusted sales appears as a dotted line through the year 2000.

The range of forecasts indicates that actual future demands should fall within plus or minus 15 percent of the medium forecast in 2025 with fairly high probability. This is reflected in the medium-low to medium-high forecast range in Table A-2. However, under more extreme variations in circumstances they could vary by 30 to 40 percent from the medium forecast, as shown by the low to high forecast range.

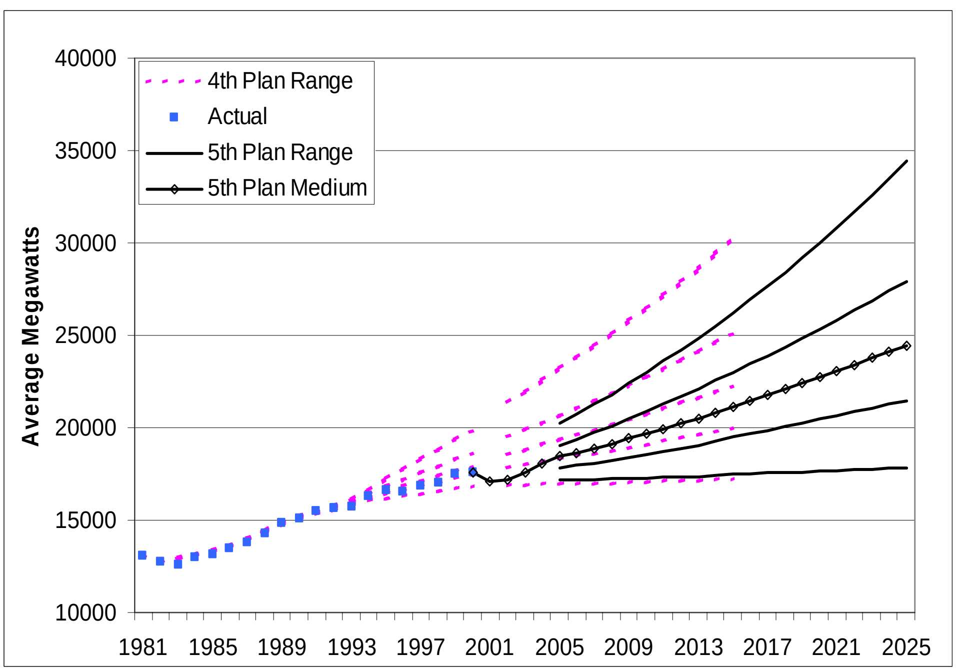


Figure A-4: Forecast Total Non-DSI Electricity Sales Compared to Fourth Plan Forecasts

Table A-2: Non-DSI Electricity Sales Forecast Range

				Growth Rates	
	2000	2015	2025	2000-15	2000-25
	(Actual)				
Low	17603	17489	17822	-0.04%	0.05%
Medium Low	17603	19482	21474	0.68%	0.80%
Medium	17603	21147	24464	1.23%	1.33%
Medium High	17603	23000	27937	1.80%	1.86%
High	17603	26187	34397	2.68%	2.72%

Maintaining growth rates from the Fourth Power Plan's demand forecasts after 2005 implicitly assumes that the underlying assumptions remain about the same in terms of their effects on growth in electricity demand. The main driving assumptions in the Fourth Power Plan demand forecasts were economic growth, fuel price assumptions, and electricity price forecasts.

We have not attempted to develop a new economic forecast. However, the Fourth Plan's economic forecasts were checked for obvious deviations from actual values since the forecasts were developed in 1995.[4] The most aggregate determinates of demand are: population, households, and total non-farm employment. The number of households is the key driver of residential electricity demand growth. Actual household growth has followed the medium household forecast from the Fourth Power Plan. Population growth also tracked the medium forecast until 2000 Census data showed an upward revision in regional population. The new population count placed 2000 regional population between the medium and medium-high forecasts.

Employment forecasts are more sensitive to economic conditions than population and households. The period of sustained rapid growth in the national and regional economies during the late 1990s exceeded the Fourth Plan forecast assumptions, which were representative of longer-term sustained growth possibilities. Non-manufacturing employment, which drives the commercial sector forecasts has been closer to the medium-high forecast through 2000, although state forecasts of non-manufacturing employment that were available when the assessment was done show its growth moderating and moving back toward the medium forecast. The current slowdown in economic activity likely will have moved non-manufacturing employment back to the medium forecast or below.

The effects of robust economic growth in the late 1990s are even more apparent in manufacturing sector employment. Actual manufacturing employment moved well above the medium-high forecast in 1997 and 1998 when there was a boom in transportation equipment employment (i.e. Boeing). State forecasts available in mid-2001 expected manufacturing employment to return to medium forecast levels for 2001-2003. With the development of a recession in the fall of 2001 the manufacturing employment has probably fallen below medium forecast levels. There were some offsetting errors within the individual manufacturing sectors. In particular, electronic and other electrical equipment employment has been above the medium-high case, while paper and allied products has been below the medium-low.

[4] Council Document 2001-23, sited above.

Future natural gas prices are expected to be higher in this power plan than in the Fourth Plan. Table A-3 below compares 4th plan gas price forecasts for 2015 to this plan's natural gas price forecasts. The 2015 medium natural gas price forecast for this plan is above the high case in the Fourth Plan; a 54 percent increase. Based on the Council's Load Forecasting Models, this would imply that electricity demand might be increased by 3 to 4 percent over the Fourth Plan forecasts if nothing else changed.

Table A-3: Natural Gas Price Forecasts for 2015 (2000 $ Per Million Btu)

	4th Plan Forecast	5th Plan Forecast
Low	$ 1.85	$ 2.75
Medium Low	$ 2.16	$ 3.40
Medium	$ 2.47	$ 3.80
Medium High	$ 3.09	$ 4.30
High	$ 3.71	$ 4.90

However, the effects of higher gas prices may be offset by higher electricity prices. It is difficult to compare retail electricity prices between the two forecasts because the old price forecasting models are no longer appropriate for price forecasting in a partially restructured electricity market. The new price model addresses only wholesale electricity prices. Future retail prices will reflect both wholesale market prices and utility-owned resource costs if the system remains mixed, as it is currently. It is clear that higher natural gas prices will have an effect on electricity prices, both through the cost of utility owned natural gas-fired generation and through the wholesale market price of electricity. Higher electricity prices have a larger downward effect on electricity consumption than the upward effect that a comparable increase in natural gas prices would have. In the end, it isn't clear whether the changes in natural gas and electricity prices would cause a net increase or decrease in electricity consumption.

Sector Forecasts

Total non-DSI consumption of electricity is forecast to grow from 17,603 average megawatts in 2000 to 24,464 average megawatts by 2025, an average yearly rate of growth of 1.33 percent. The year 2000 is used as the base year for the forecast and growth rate calculations. It is a more representative year for examining long-term trends in demand than 2001 or 2002 would be. Table A-4 shows the forecast for each consuming sector in the medium case. Each sector's forecast is discussed in separate sections below.

Table A-4: Medium Case Non-DSI Consumption Forecast (Average Megawatts)

	2000	2005	2010	2015	2020	2025	Growth Rates		
	(Actual)						2000-25	2000-15	2005-25
Total Non-DSI Sales	17,603	18,433	19,688	21,147	22,742	24,464	1.33	1.23	1.43
Residential	6,724	7,262	7,687	8,230	8,809	9,430	1.36	1.36	1.31
Commercial	5,219	5,453	5,771	6,146	6,556	6,993	1.18	1.10	1.25
Non-DSI Industrial	4,836	4,904	5,397	5,919	6,505	7,150	1.58	1.36	1.90
Irrigation	652	629	641	654	667	681	0.17	0.02	0.40
Other	172	185	191	198	204	211	0.82	0.93	0.66

Residential Sector

Residential electricity consumption is forecast to grow by 1.36 percent per year between 2000 and 2025. Figure A-5 illustrates the range of the residential consumption forecast, compared to historical data, and the forecasts from the Council's Fourth Power Plan. The medium case residential demand forecast for 2005 is 161 average megawatts lower than the Fourth Plan forecast for that year. The forecast growth of residential sector use of electricity is slightly less than the growth from 1986-1999 of 1.8 percent annually.

The medium residential forecast remains just below the Fourth Plan medium case. This adjustment reflects the fact that the Fourth Plan slightly over forecast actual residential sales between 1995 and 2000, and that there are expected to be some longer-term effects of utility and consumer efficiency investments in response to the electricity crisis and high prices of the last couple of years. The 2005 residential demand forecast is 161 megawatts lower than the Fourth Plan forecast for 2005, or a 2.2 percent reduction in the forecast consumption level.

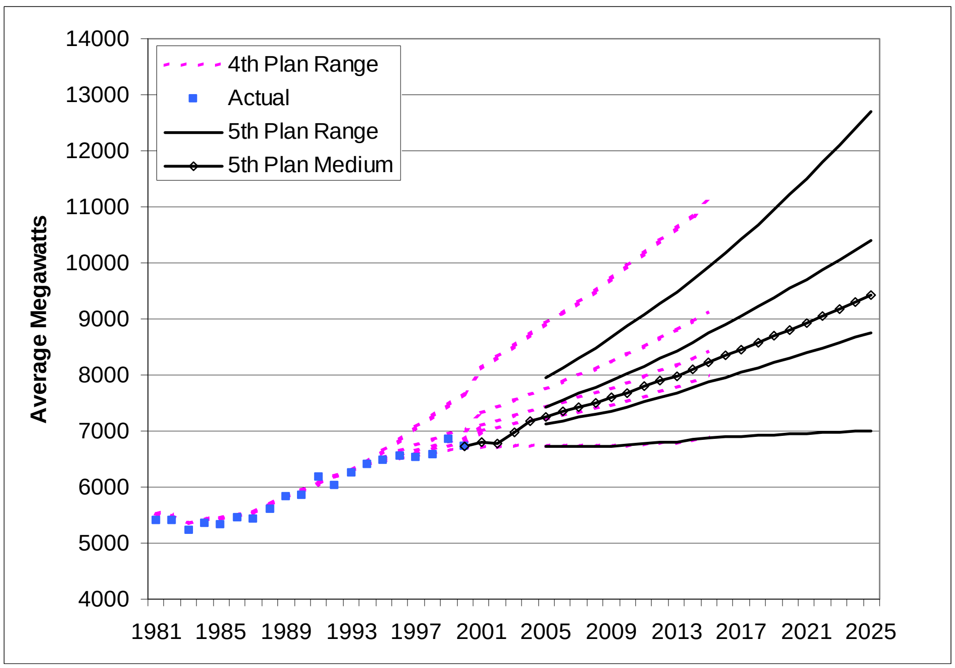


Figure A-5: Forecast Residential Electricity Sales Compared to Fourth Plan Forecasts

Although the near-term forecast shows a significant dip in residential consumption in 2001, the reduction in consumption is dampened significantly by making the adjustment to a "price effects" forecast in 2001. That is, the forecasts are intended to reflect what demand for electricity would be if new conservation programs are not implemented. The consumption levels before 2001 include the effects of conservation programs on electricity use, thus reducing consumption. The residential sector sales forecast is the only one affected by programmatic conservation in 2001 in the medium case of the Fourth Power Plan. The adjustment to eliminate the savings from conservation programs increased the residential electricity use forecast by 191 average megawatts in 2005.

It should be noted that the forecasts presented here have not been adjusted for the future effects of new building or appliance codes that have been put into effect since the Fourth Plan forecasts were done. These changes in minimum energy efficiency would reduce the future "price effects" forecast shown here. The analysis to make these adjustments has not been completed at this time.

Commercial Sector

Commercial sector electricity consumption is forecast to grow by 1.18 percent per year between 2000 and 2025, increasing from 5,219 to 6,993 average megawatts. Figure A-6 illustrates the forecast. Compared to the Fourth Power Plan forecast of commercial electricity use, the medium case has been adjusted upwards to reflect the fact that there has been a slight tendency to under forecast commercial demand since 1995. The forecast for 2005 is 325 average megawatts higher than the 2005 medium forecast in the Council's Fourth Power Plan.

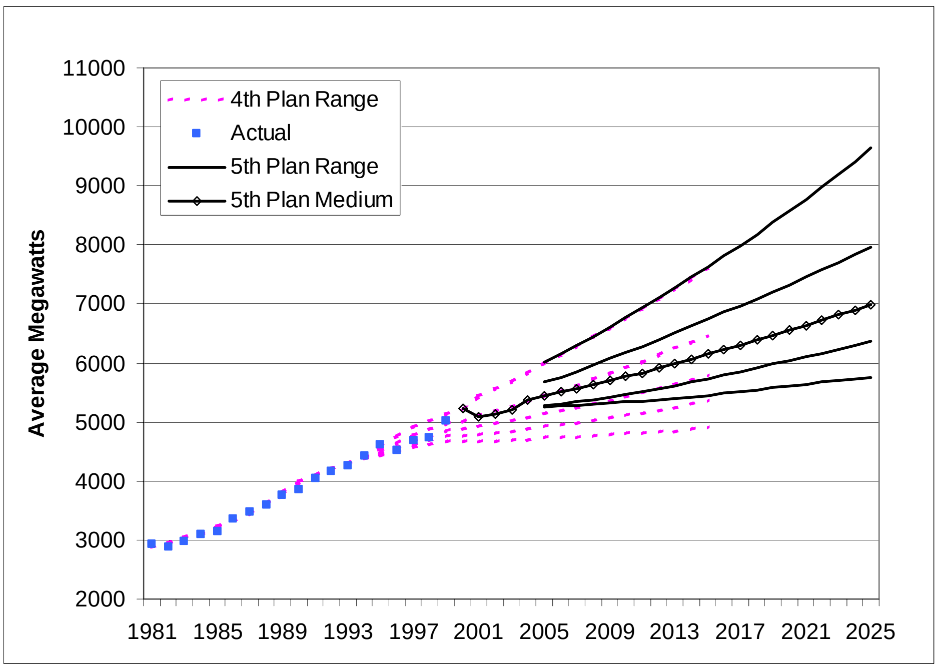


Figure A-6: Forecast Commercial Electricity Sales Compared to 4th Plan Forecasts

Comments in the residential section about the effects of new building and appliance efficiency codes apply to the commercial sector as well. In the medium commercial sector forecast, there is no adjustment made for conservation programs in shifting to the medium price effects forecast in 2001. The conservation program adjustment does affect the starting point for the medium-high and high forecast in 2005. It also affects the 4th plan forecast shown in the graph. The transition from a "sales" forecast to a "price effects" forecast is apparent in the high case, the upper line in Figure A-6. The near-term forecast dip in the medium case is the expected effect of recent price changes and economic recession.

The growth forecast for the commercial sector is for a significantly slower growth than in the past. Between 1986 and 1999 commercial electricity use grew at 3.1 percent per year.

Therefore, the forecast growth rate of 1.2 percent represents a big slowdown in commercial growth. This slowdown was present in the 4th power plan forecasts as well. But there has not been a significant under forecasting trend since the Fourth Plan forecast of commercial demand was done even though the region has experienced a robust growth cycle during these years. Figure A-7 shows the forecast compared to actual sales for 1994 through 1999. Although actual sales for 1995 and 1999 are above and at the medium-high, respectively, the other four years are at or below the medium case forecast.

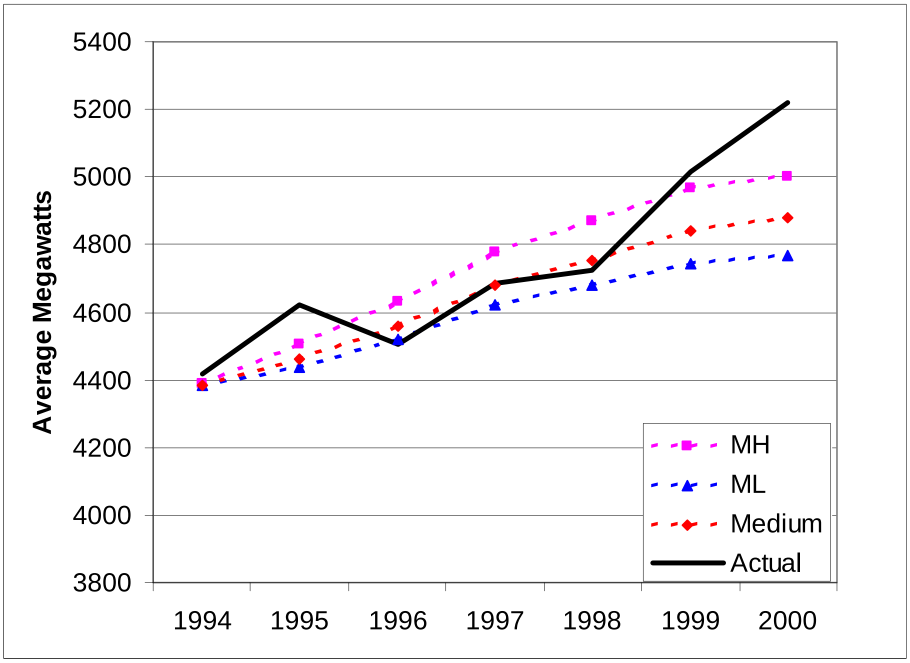


Figure A-7: Fourth Plan Commercial Forecast Performance

Several factors could help explain the forecast of slower growth of commercial electricity use. The underlying forecast of employment growth in the non-manufacturing sectors is significantly slower than historical growth. This alone could account for much of the decreased electricity demand growth forecast. In addition, the demand forecasting model accounts for building vintages and efficiency. As newer, more energy efficient, buildings that have been subject to building efficiency codes enter the stock and replace older buildings the electricity use per square foot of buildings will tend to decrease. Such factors may account for the decreased rate of growth of commercial electricity use, but the Council continues to evaluate the commercial forecasts to see if these forecasts might understate future commercial electricity needs. The Council would like to hear the views of utilities and the public on this issue.

Non-DSI Industrial Sector

Industrial electricity demand is difficult to forecast with much confidence. Unlike the residential and commercial sectors where energy use is predominately for buildings, and therefore reasonably uniform and easily related to household growth and employment, industrial electricity use is extremely varied. Further, the use tends to be concentrated in a relatively few very large users instead of spread among many relatively uniform users.

The direct service industries (DSIs) of Bonneville are treated separately in this discussion because this hand-full of plants (mainly aluminum smelters) accounts for nearly 40 percent of industrial electricity use. In addition, the future of these plants is highly uncertain. Large users in a few industrial sectors such as pulp and paper, food processing, chemicals, primary metals other than aluminum, and lumber and wood products dominate the remainder of the industrial sector's electricity use. Many of these sectors are declining or experiencing slower growth. These traditional resource based industries are becoming less important to the regional electricity demand while new industries, such as semiconductor manufacturing are growing faster.

Non-DSI industrial consumption is forecast to grow at 1.58 percent annually from 2000 to 2025 (see Figure A-8). Electricity consumption grows from 4,836 average megawatts in 2000 to 7,150 in 2025. The medium-high and medium-low forecasts are about 20 and 30 percent higher and lower than the medium forecast, respectively. This reflects the greater uncertainty in forecasting the industrial sector's electricity demand. In addition, the actual industrial consumption data is becoming more difficult to obtain as some consumers gain access to electricity supplies from independent marketers instead of their local distribution utility who must report their electricity sales.

The near-term forecast reflects a severe reduction of consumption in 2001 and 2002. Higher electricity prices are expected to continue to repress industrial electricity use. 2005 demand remains significantly, 1,022 average megawatts; lower than the 2005 forecast for Fourth power plan.

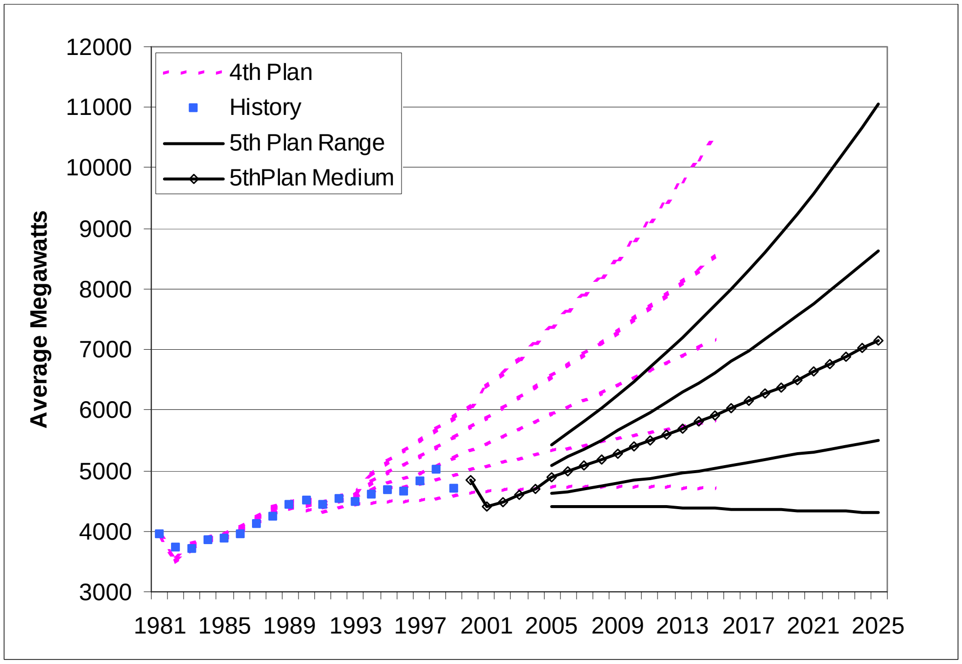


Figure A-8: Forecast Non-DSI Industrial Electricity Sales Compared to Fourth Plan Forecasts

Irrigation and Other Uses

Irrigation and other uses are relatively small compared to the residential, commercial and industrial sectors. Irrigation has averaged about 640 average megawatts between 1986 and 1999 with little trend discernable among the wide fluctuations that reflect year-to-year weather and rainfall variations. Other includes streetlights and various federal agencies that are served by Bonneville. It is relatively stable and averaged about 180 megawatts a year between 1986 and 1999.

Unlike most other sectors in the forecast, the irrigation forecast range has been changed substantially, although due to its small size it has little effect on total demand. Analysis showed that the average irrigation use over the past 20 years was substantially lower than where the medium forecast in the Fourth Plan started. The 2005 consumption was lowered to 629 average megawatts, compared to a Fourth Plan value of 700 average megawatts in that year. The forecast medium case, shown in Figure A-9, includes very little growth, as has been the case for the last 10 or more years. The range considers a high case growth of 0.7 percent a year and the low case considers that irrigation electricity use could decline by 0.8 percent annually. Substantial expansion of irrigated agriculture seems unlikely given the competing uses of the oversubscribed water in the Pacific Northwest.

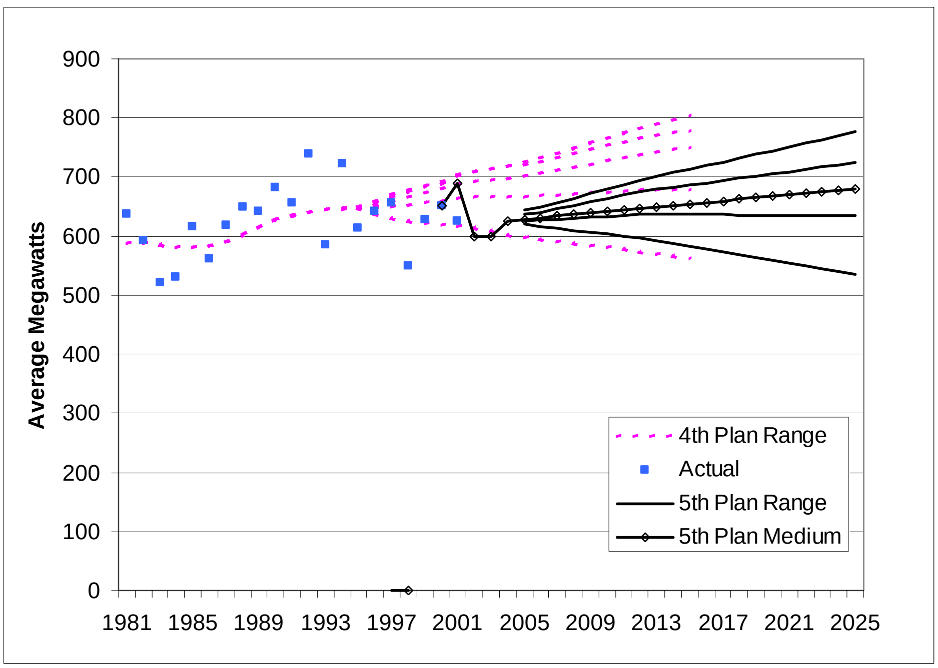


Figure A-9: Forecast Irrigation Electricity Sales Compared to Fourth Plan Forecasts

Other electricity use did not have a range associated with its forecast in the Fourth Power Plan. The other forecast is unchanged from the Fourth Plan forecast, growing at just under one percent annually.

Aluminum (DSIs)

Background

Direct Service Industries, or DSIs, refers to a group of industrial plants that have purchased electricity supplies directly from the Bonneville Power Administration. In the past, most of these plants obtained all of their electricity needs from Bonneville. Recently, many of these plants have diversified their electricity supplies, either by choice or because of reduced allocations from Bonneville. This discussion generally addresses the total electricity requirements of these industrial consumers regardless of source.

"DSIs" is often used interchangeably with aluminum smelters because aluminum smelters account for the vast bulk of this categories' electricity consumption. When all of the region's ten aluminum smelters were operating at capacity, they could consume about 3,150 average megawatts of electricity. Table A-5 shows the smelters, their locations, their aluminum production capacity and the amount of electricity they were capable of consuming at full operation.

Table A-5: Pacific Northwest Aluminum Plants

Owner	Plants	County	Capacity	Electricity Demand
			(M tons/yr.)	(MW)
Alcoa	Bellingham WA	Whatcom	282	457
Alcoa	Troutdale OR	Multnomah	130	279
Alcoa	Wenatchee WA	Chelan	229	428
Glencore	Vacouver WA	Clark	119	228
Glencore	Columbia Falls MT	Flathead	163	324
Longview Aluminum	Longview WA	Cowlitz	210	417
Kaiser	Mead WA	Spokane	209	390
Kaiser	Tacoma WA	Pierce	71	140
Golden Northwest	Goldendale WA	Klickitat	166	317
Golden Northwest	The Dalles OR	Wasco	84	167
Total			1663	3145

Source: Metal Strategies, LLC, *The Survivability of the Pacific Northwest Aluminum Smelters*, Redacted Version, February, 2001.

This amount of electricity is significant in the Pacific Northwest power system. The amount of power used by these aluminum plants in full operation could account for 15 percent of total regional electricity use. When operating, the electricity use of these plants tends to be very uniform over the hours of the day and night. However, the aluminum plants have faced increasing difficulty operating consistently over the past 20 years because of increased electricity prices and aluminum market volatility.

Aluminum smelting in the region started during the early 1940s to help build up for the war effort and to provide a market for the hydroelectric power production in the region. Smelting capacity was expanded throughout the 1960s and 1970s. Since then no new plants have been added, although improvements to the existing plants have resulted in some increases in smelting capacity. The 10 aluminum plants in the Pacific Northwest accounted for a significant share of the U.S., and even the world, aluminum smelting capacity. Before the millennium, the region's smelters accounted for 40 percent of the U.S. aluminum smelting capacity and about 6 to 7 percent of the world capacity. Their presence in the region is largely due to the historical availability of low priced electricity from the Federal Columbia River Power System. Aluminum smelting is extremely electricity intensive. Electricity accounts for about 20 percent of the total cost of producing aluminum worldwide and is therefore a critical factor in a plant's ability to compete in world aluminum markets. With increasing electricity prices this share is now substantially larger for the region's smelters, perhaps as much as one-third of costs.

Deteriorating Position of Northwest Smelters

The position of the region's aluminum smelters in the world market has been deteriorating since 1980. This is due to a combination of increased electricity prices, declining world aluminum prices and the addition of lower cost aluminum smelting capacity throughout the world.

Around 1980 the cost and availability of electricity supplies to the Pacific Northwest aluminum plants began to change dramatically. At the time, Bonneville supplied all of the smelters' electricity needs at very competitive prices. However, between 1979 and 1984 Bonneville's electricity prices increased nearly 500 percent. This is illustrated in Figure A-10, which shows Bonneville preference utility rates for electricity since 1940. The aluminum plants, along with other electricity consumers in the region, suddenly found themselves in a much less advantageous position with regard to electricity costs.

As the region's aging smelters have struggled to stay competitive in a world aluminum market, the conditions of their electricity service have also been changing. During the 1970s, the region's electricity demand began to outgrow the capability of the hydroelectric system. The fact that aluminum smelters had no preference access to the Federal hydroelectric energy meant that their electricity supplies were threatened. The Pacific Northwest Electric Power Planning and Conservation Act of 1980 (The Act) extended the DSI access to Federal power in exchange for the DSIs covering, for a time, the cost of the residential and small farm exchange for investor-owned utility customers. In addition, the DSIs were to provide a portion of Bonneville's reserve requirements through interruptibility provisions in their electricity service.

Over the years since the Act, the DSI service conditions and rates have changed in response to changing conditions. After the dramatic electricity price increases of 1980, smelters became more vulnerable to changing aluminum market conditions. Between 1986 and 1996 Bonneville implemented electricity rates for the aluminum plants that changed with changes in aluminum prices. These rates were intended to help the aluminum plants operate through difficult aluminum market conditions, and to help stabilize Bonneville's revenues. Until 1996, aluminum plants in the region bought all of their electricity from Bonneville, with the exception of one plant that acquired part of its electricity supply from a Mid-Columbia dam. In the 1996 rate case, aluminum plants chose to reduce the amount of energy they purchased from Bonneville to about 60 percent of their demand in order to gain greater access to a (then) very attractive wholesale power market. In the 2001 rate case, Bonneville further reduced the aluminum allocation to about 45 percent of smelters' potential demand, or about 1,425 megawatts. The aluminum smelters are now required to obtain over half of their electricity requirements in the wholesale electricity market or from other non-Bonneville sources.

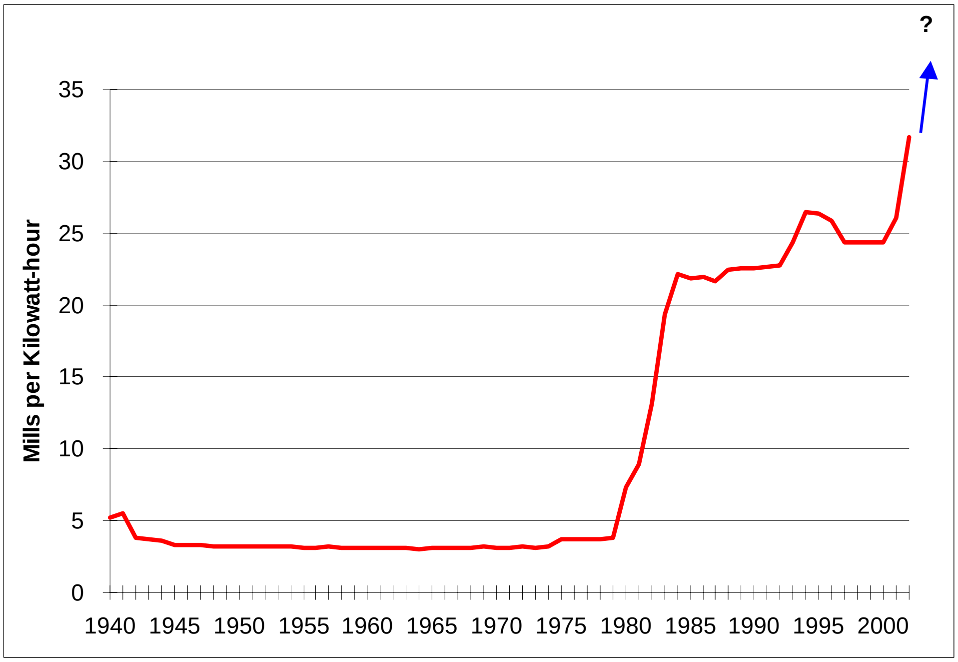
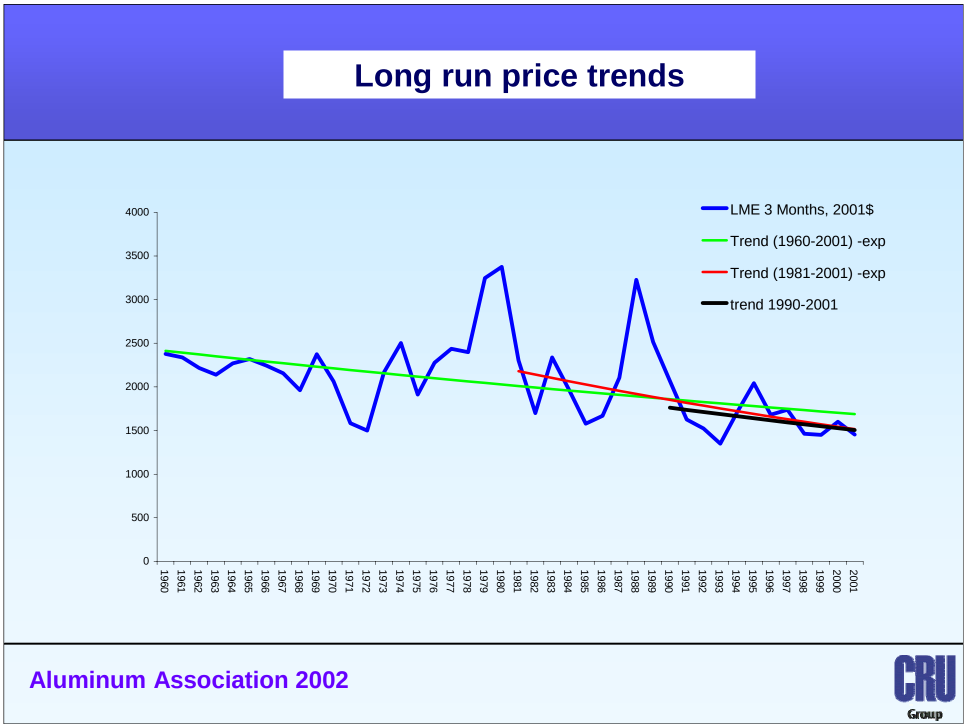


Figure A-10: Bonneville Power Administration Preference Rates

Most new world aluminum smelting capacity has been added outside of the traditional Western economies, often in countries where social agendas may be driving the capacity decisions as much as aluminum market fundamentals. The disintegration of the former Soviet Union and the liberalization of trade in China have had a significant effect on the development of a world aluminum market. The addition of more capacity over time and improving aluminum smelting technology is reflected in declining aluminum price trends. Figure A-11 shows aluminum prices from 1960 through 2001. Trends calculated over different time periods all show a consistent downward trend. On average, aluminum prices corrected for general inflation decreased by about 0.8 percent annually from 1960 to 2001. The downward trend is particularly pronounced from 1980 to the present.

The steady improvement in aluminum smelting technologies over time has meant that the region's smelters have tended to grow relatively less competitive in terms of their operating costs as new more efficient capacity has been added throughout the world. By investing in improved technology some of the region's smelters have been able to partially offset the effects of these declining cost trends. In addition, the worsening position of the region's aluminum smelters relative to other aluminum plants may have been partly offset by the decreasing capital costs and debt as older plants and equipment depreciate. Nevertheless, a growing share of the regional smelting capacity has become swing capacity. That is, plants could operate profitably during times of strong aluminum prices or low electricity prices, but tended to shut down during periods of less favorable market conditions.



Source: CRU International Ltd., Presentation to Aluminum Association 2002.

Figure A-11: Aluminum Price Trends

Caught in the pincers of decreasing aluminum prices and increasing electricity prices, many of the region's smelters have reached a critical point. Events since the spring of 2000, in both the electricity and aluminum markets, have had a dramatic effect on the region's aluminum plants. By mid-summer of 2001, all of the region's aluminum smelters had been shut down for normal production, either because of high electricity prices and poor aluminum market conditions or because Bonneville bought back the electricity to help meet an expected shortfall of electricity supplies and remarket the electricity at much higher market prices. The elimination of aluminum electricity load played a key role in avoiding electricity shortages in the summer of 2001 and the following winter.

Sharing of the savings from remarketing aluminum plants' electricity helped ease the financial strain on aluminum companies and their employees of a long shut down. During 2002 electricity prices in the wholesale market fell to low levels, but aluminum prices remained very low and only a few smelters found it desirable to partially return to production. In addition, Bonneville's rates have remained high. There does not appear to be much optimism for a quick recovery of aluminum prices. Some analysts expect the global aluminum market to remain in surplus until 2005.

Currently, three of the region's smelters have closed permanently, another is in bankruptcy proceedings and appears likely to close permanently, and others are in dire financial straits. During 2003 aluminum plants only consumed 423 average megawatts of electricity. Three plants that had partially reopened have cut back or suspended operations.

With aluminum market recovery uncertain, and with expected future electricity prices too high for most aluminum plants to operate profitably, future aluminum electricity use is expected to be much lower than in previous Council plans. The ability of aluminum plants to operate depends critically on the level of electricity prices. With the medium natural gas price assumptions, the Council currently forecasts long-term spot market electricity prices to be in the $30 to $40 per megawatt-hour range in year 2000 dollars (see Figure A-12). Few, if any, of the region's smelters would be able to operate with electricity prices at that level. It is unclear how much of the aluminum load Bonneville might serve in the future, but Bonneville's future electricity prices may also be higher than aluminum plants can afford except when aluminum prices are especially high.

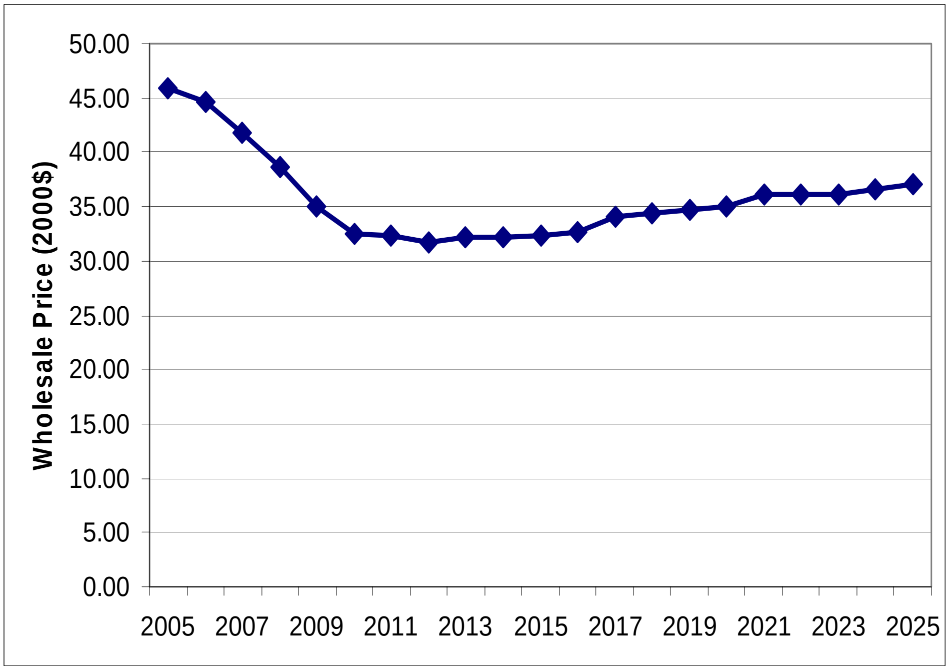


Figure A-12: Medium Case Wholesale Price Forecasts for Mid-Columbia Electricity

A Simple Model of Aluminum Electricity Demand

A simple model of Pacific Northwest aluminum plants was developed to relate the likelihood of existing aluminum plants operating to different levels of aluminum prices and electricity prices. Given an aluminum price, the model estimates what each aluminum plant in the Northwest could afford to pay for electricity given its other costs. Then, for a given electricity price, the electricity demand of the plants that can afford to operate make up the aluminum electricity demand in the region. Basic data for the model came from the July 2000 study cited as the source for Table A-5, advice from the Council's Demand Forecasting Advisory Committee, and comments on a draft aluminum forecast paper.[5]

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[5] "Forecasting Electricity Demand of the Region's Aluminum Plants." Northwest Power Planning Council document 2002-20. December, 2002.

Figure A-13 illustrates the relative competitiveness of the seven remaining Northwest aluminum plants as represented in the model. (It is assumed that the other three smelters in Troutdale, Oregon, Longview, Washington, and Tacoma, Washington are permanently closed.) Figure A-13 shows the amount that each plant could afford to pay for electricity given an assumed aluminum price of $1,500 per ton[6] (about 67 cents a pound), which is about the average aluminum price over the past several years.

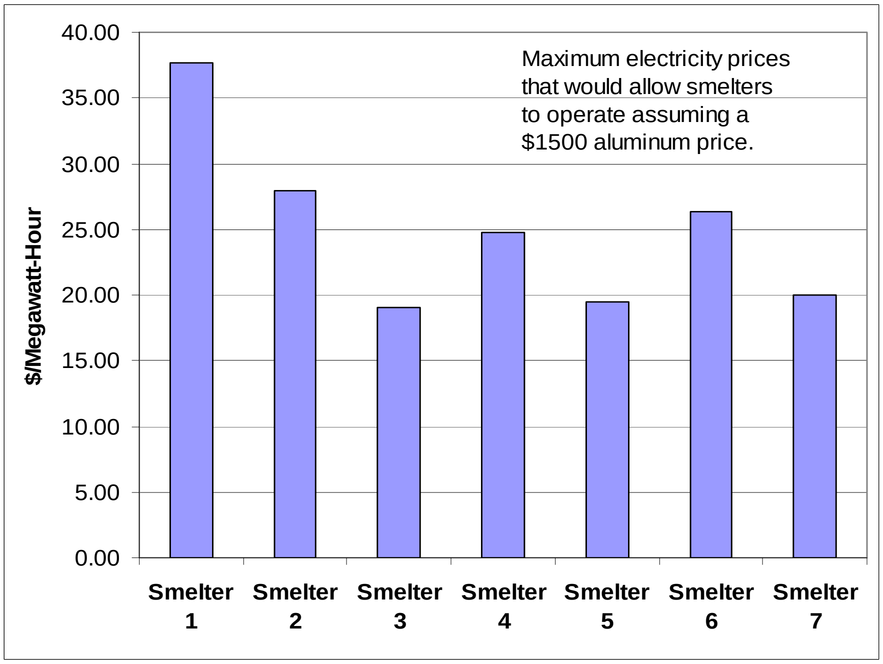

Figure A-13: Affordable Electricity Price Limits of PNW Aluminum Smelters At $1,500 Per Ton Aluminum Prices

One aluminum plant in the region is very efficient and is likely to operate under a wide range of electricity and aluminum prices. Three other smelters could pay around $25 a megawatt-hour for electricity if aluminum prices were $1,500 a tonne, which is higher than aluminum prices have averaged since 2000. The other smelters could only afford to operate at electricity prices near $20 per megawatt-hour.

There are some important limitations to this simple model. It is intended to represent whether aluminum plants would be willing to operate for an intermediate time period. The costs used in the model include an amount above the pure short-term operating costs to allow sufficient ongoing capital investments to maintain the plant's capability to produce. But the costs do not include sufficient returns on capital to justify the long-term operation of the plant.

Thus, the model does not address the question of when a plant would be likely to close permanently. In order to remain in operation, a plant would have to be able to recover sufficient funds during periods of high aluminum prices and low electricity prices to recover an adequate return on investment. However, as plants depreciate, or as they are sold at discounted prices, capital recovery becomes a smaller part of the decision, and strategic positioning in global

[6] "Tonne" refers to a metric ton, which contains 2,240 pounds.

markets may enable some plants to remain available for operation when conditions are attractive enough. The implicit assumption in the model is that if a plant can operate for the intermediate term under expected electricity and aluminum prices, then it will be able to recover sufficient returns during favorable cyclical market conditions to survive in the long term.

The model does not address the dynamics of temporary closures of aluminum plants or their return to operation. The dynamics of aluminum smelter operations are important considerations for assessing their potential value as demand-side reserves. The potential demand-side reserves that might be provided by aluminum plants include: very short-duration interruptions for system stability purposes; interruptions of up to four hours during extreme peak electricity price spikes; and long-term shut downs of several months to a year or more to address periods of poor hydroelectric conditions or other periods of significant generation capacity shortages. These issues will be addressed outside of the simple aluminum model described here. In the Council's portfolio risk model, aluminum plant closure, reserves, and reopening conditions are related to uncertain variations in electricity and aluminum prices. This will be discussed in more detail later.

Model Results

By varying the aluminum and electricity prices over a range of possible values, the simple model can be used to simulate expected aluminum electricity demands under varying conditions. Aluminum prices were varied between $1,050 and $2,250 per tonne in $100 increments. For each aluminum price, electricity prices were varied between $20 and $40 per megawatt-hour. This generated 91 different estimates of aluminum plant electricity demand under the varying aluminum and electricity combinations. Figure A-14 shows the results of this exercise.

A couple of bracketing points are evident. First, at aluminum prices below $1,150 per tonne, none of the Northwest aluminum plants can operate profitably at any electricity price between $20 and $40 per megawatt-hour. Aluminum prices have seldom been below $1,200 a ton (in 2002 prices) in the past 20 years. On the other extreme, all seven smelters could operate at aluminum prices above $2,050 per tonne for electricity prices up to $40 per megawatt-hour.

If past trends in aluminum prices continue, aluminum prices might decline at about one percent a year. That would mean that average aluminum prices might average less than $1,500 over the next 20 years. Of course, there will be considerable volatility around that trend. At this point in the Council's planning process, we do not have a range of future electricity prices that match the range of natural gas prices we are assuming for our analysis. Preliminary analysis with the medium natural gas price forecast shows that wholesale electricity prices under medium assumptions (see Figure A-12) could be between $35 and $40 per megawatt-hour over the long term. In those ranges of electricity and aluminum prices, it is unlikely that more than two aluminum plants could operate, and electricity demand by aluminum smelters in the region would be less than 900 megawatts.

The results in Figure A-14 include an assumption that one smelter will continue to have access to low cost mid-Columbia dam power for part of its electricity demand. Access to some lower cost supplies of electricity from Bonneville or other sources and further investments in smelter efficiency may improve the ability of some smelters to stay in operation. The simple aluminum model was used to see what effect an offer of 100 megawatts of electricity priced at $28 per megawatt-hour would have on smelter operations. Assuming an availability of such electricity supplies changes the model results for the 91 combinations of aluminum and electricity prices.

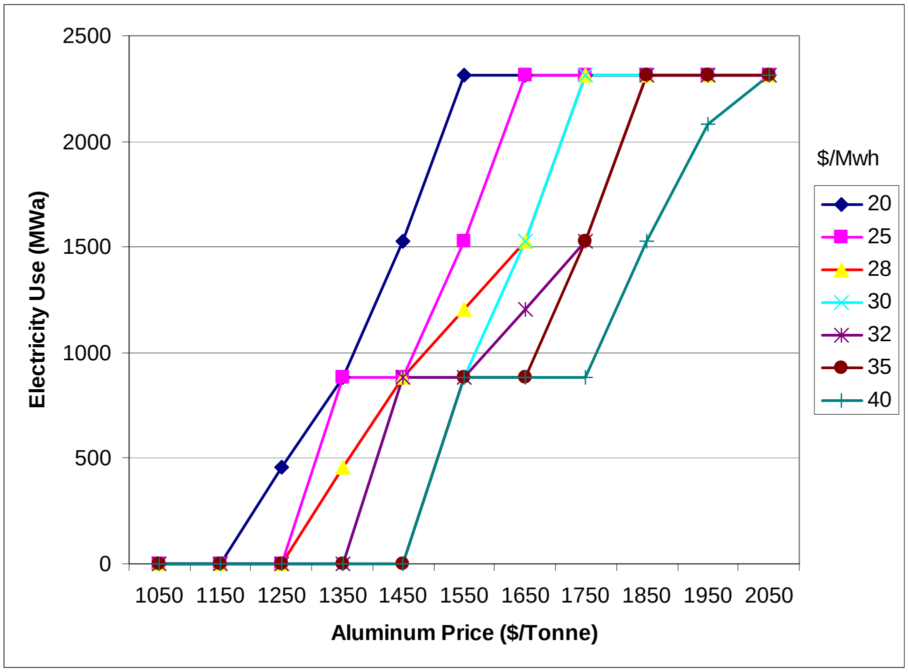

Figure A-14: Spectrum of Potential Aluminum Smelter Electricity Demands

In order to more easily illustrate these effects, an expected value of electricity demand was calculated for each assumed electricity market price. This was done by weighting electricity demand simulated at different aluminum prices by the percent of days in the last ten years that actual aluminum prices fell into that range. These expected electricity demands are shown in Figure A-15. Another way of characterizing an individual bar in Figure A-15 is that it is a weighted average of the electricity use in an individual line from Figure A-14.

Using just market electricity prices and the one mid-Columbia supply contract, expected smelter electricity demands ranged from 783 megawatts at $40 per megawatt-hour electricity prices to 2,138 megawatts at $20 electricity prices. This is shown in the left-most bar for each electricity price group in Figure A-15.

If smelters could arrange to purchase 100 megawatts of power priced at $28 per megawatt-hour, it is estimated to have a relatively small effect on expected aluminum operations (see the middle bars in Figure A-15). At market prices below $28 the expected electricity demand of aluminum smelters is actually reduced by the higher priced power supply. If market power prices were $40, the availability of 100 MW of power at $28 per megawatt-hour is estimated to increase the expected value of aluminum smelters' electricity demand of from 783 to 875 megawatts, a relatively small effect. If smelters could arrange a block of power at $20 (illustrated by the right-most bars in Figure A-15) the estimated increase in electricity demand at the $40 market price would be 314 megawatts. That increase is roughly the electricity demand of one additional smelter.

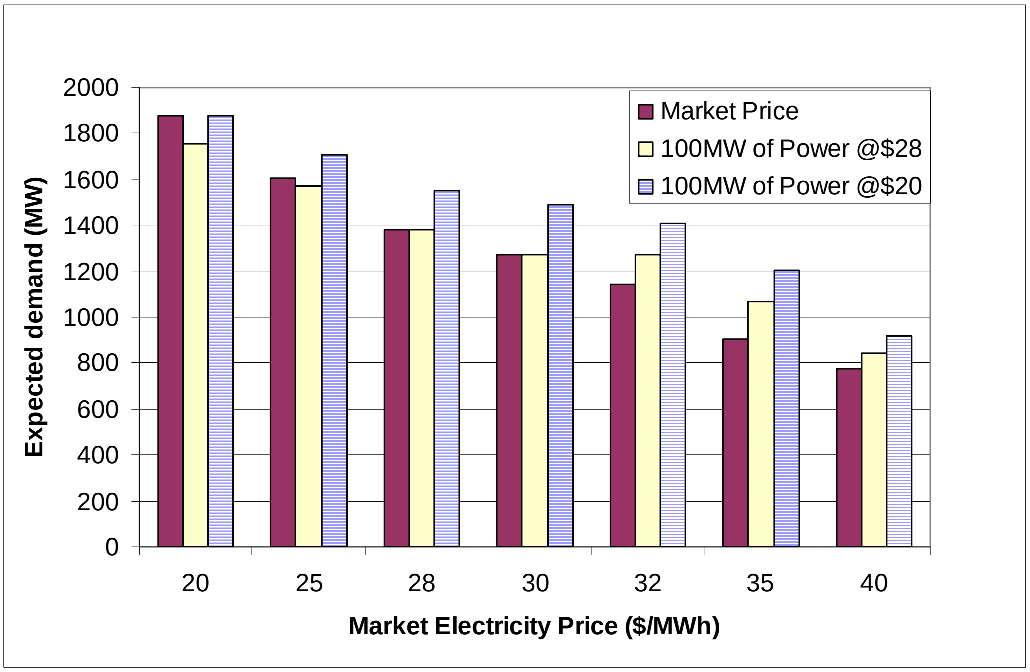

Figure A-15: Expected Aluminum Plant Electricity Demand (Effect of Special Electricity Supplies)

The analysis above addresses the question of whether the existing smelters in the region are likely to operate under different aluminum and electricity market conditions. It does not address the likelihood of permanent closure. Historically, older and less efficient smelters are not frequently closed permanently. Their depreciated capital costs allow them to operate when electricity and aluminum prices are attractive. They may provide an inexpensive option for aluminum supplies in tight aluminum markets. In addition, permanent closure may involve expensive site clean up.

The result is that the region might retain a large, but uncertain, electricity demand. If such a demand is required to be served when they need electricity, it can be very costly for their electricity supplier to maintain generating capacity to serve the potential demand. If serving the demand is optional, however, through either interruption agreements or the smelters purchasing available power in the market, it can have attractive features that may reduce electricity price volatility. The future of aluminum operations in the region may depend on the ability of aluminum plants to find, and get value for, their potential for complementing the power system in a competitive wholesale market.

Mid-Term Aluminum Demand Assumption

The Council is required to include in its power plans a 20-year forecast of demand. The Council is also increasing its focus on the nearer term for purposes of reliability and adequacy analysis. For these purposes, a specific forecast of total electricity demand is useful. And for that, specific assumptions about DSI demands are needed. This section presents such a best guess forecast, but it is important to keep the extreme uncertainty regarding this assumption in mind when evaluating reliability, adequacy, or long-term resource strategies.

Figure A-16 shows the assumed mid-term pattern of aluminum electricity demand through 2005 compared to the Council's assumption for the Fourth Power Plan. In the current forecast, electricity demand is assumed to recover to about 1,000 megawatts by 2005. This would be consistent with two aluminum smelters operating plus 60 average megawatts of non-aluminum DSI demand. If the aluminum model is reasonably accurate, and if electricity can be acquired for $30 to $35 per megawatt-hour, this implies that aluminum prices would have to recover to $1,450 to $1,550 per tonne by 2005. The higher end of that range is similar to average aluminum prices during the past 10 years. Although aluminum prices have risen to above $1,600 in the first four months of 2004, given recent trends and events in world aluminum markets, the range of $1,450 to $1,550 per tonne should be viewed as a reasonably optimistic assumption for future aluminum prices.

The forecast is significantly more pessimistic about aluminum plants' ability to operate than the Council's Fourth Power Plan. This is consistent with a prolonged period of low aluminum prices during 2001 through 2004, with higher forecasts of electricity prices. It also is more pessimistic about the ability of some smelters to survive a prolonged period of high electricity prices, poor aluminum prices, and uncertainty about electricity markets and contracts.

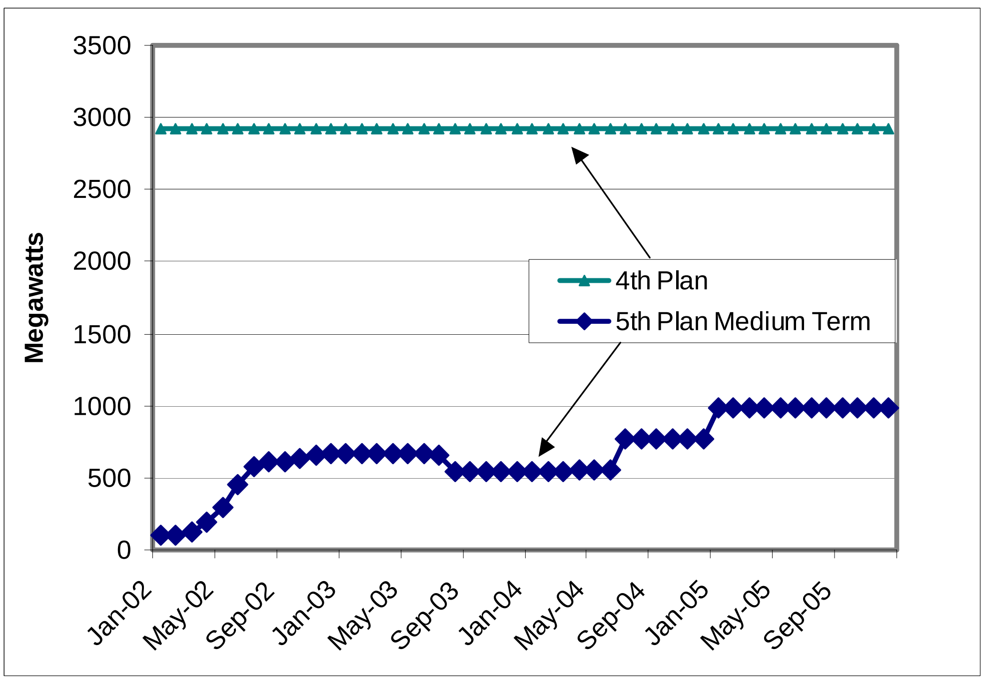

Figure A-16: Medium Case Assumptions for Aluminum Demand Recovery to 2005 (Comparison to 4th Plan Assumptions)

Long-Term Forecasts of Aluminum Smelter Electricity Demand

For the long-term medium forecast, the 2005 forecast level is extended to the end of the forecast in 2025. Figure A-17 shows the medium total DSI demand assumptions extended to 2025 compared to the forecasts in the Council's Fourth Power Plan. In this figure, non-aluminum DSI loads of 60 average megawatts have been added to the aluminum forecast. Again, this forecast does not imply that Bonneville will serve all of this DSI demand; it has been labeled DSI for convenience. The medium case is 1,260 average megawatts below the forecast in the Council's last power plan.

Although the loads after 2005 are shown as constant, we would actually expect them to be quite volatile around that trend. In addition, since aluminum prices are expected to trend downward over time, and natural gas prices upward, it may become increasingly difficult for regional smelters to operate as the future unfolds.

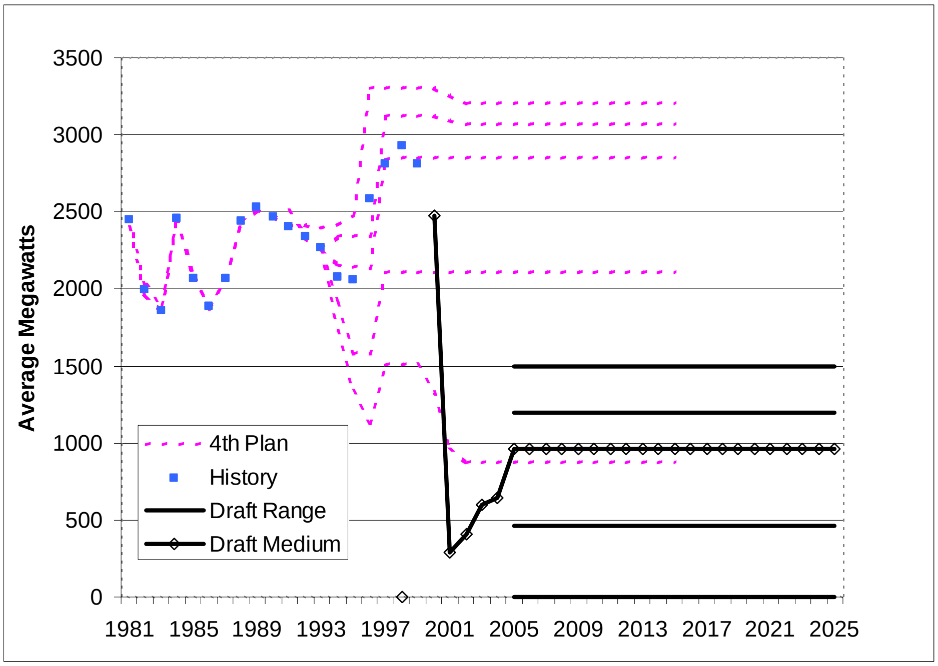

Figure A-17: Demand Assumptions for DSI Industries Compared to Fourth Plan Assumptions

In all previous power plans, the Council has assumed a range of DSI demands. The high DSI demand assumption was paired with the high economic assumptions and demand forecast. This pairing of aluminum and other forecasting assumptions was based on the theory that aluminum prices would be the key variable and that aluminum prices were likely to be positively correlated with rates of economic growth. For illustrative purposes, a similar approach has been used to develop a range of aluminum demand assumptions. Figure A-18 shows the aluminum demand assumptions included in each forecast case for the Council's Fourth Power Plan compared to the outlook now.

Only in the low forecast of the Fourth Power Plan was there a large reduction of aluminum demand. It was assumed that Bonneville or other relatively affordable power would be available to the aluminum plants. Thus, most of the plants were assumed to remain competitive, or at least operate as swing plants, in the medium case. Now the expectation is that only between zero and four of the region's smelters could survive to operate at significant capacity factors.

The expectation of higher electricity prices and rapid expansion of aluminum smelting capacity in China and other areas has changed the outlook for the region's smelters substantially. Aluminum prices are still important, but the cost of electricity has become a critical element for Northwest smelters. Since electricity prices are related to natural gas prices in the long-term, and high natural gas prices are associated with the high economic growth case, it is also reasonable to expect that lower aluminum demand could be associated with the higher economic growth cases. However, if high aluminum prices are still associated with higher economic growth, then it is possible that the high economic growth cases will favor aluminum plant operation given that electricity prices are not too high. In short, it is not clear how aluminum demand will be related to the economic growth conditions. The proposed solution to this dilemma is to forecast aluminum electricity demand separately from other demands for electricity.

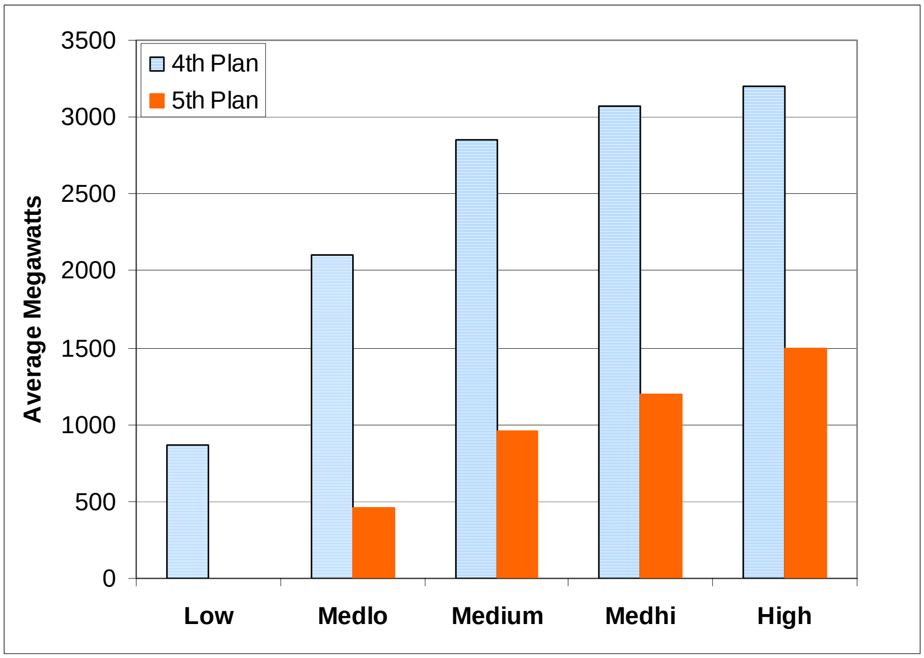

Figure A-18: Aluminum Electricity Demand Assumptions for 2005-2025 Compared to the Council's Fourth Power Plan

Therefore, the Council is modeling aluminum industry demands explicitly in its portfolio model.

Aluminum Demand in the Portfolio Analysis

Since aluminum demands are very significant in determining future electricity demands of the region, they are an important source of uncertainty that should be modeled and addressed directly in the Council's resource planning process. In developing the Fifth Power Plan, the Council modeled aluminum plants as uncertain loads that depend on aluminum prices and electricity prices. This was done using the Council's portfolio analysis model. The simple model described above was the basis for the relationship between aluminum electricity demand and electricity and aluminum prices developed for the portfolio model. As it simulated alternative futures, the portfolio model randomly selected different electricity prices and aluminum prices. These conditions were used to estimate the aluminum plants' demand for electricity.

However, the simulations contained in the portfolio model take into account, in addition to the basic cost information for each plant, assumptions about cost of shutting down and restarting plants and minimum down time and up time. For example, it is assumed that the decision to restart a plant would include the startup costs and that, if a plant were to reopen, it would remain open for at least 9 months. Similarly, a plant may not close immediately when current prices make it unprofitable, and once it does close it would likely remain closed for a period of at least 9 months. The portfolio model also assumes that if a plant does not operate for a five-year period, it will be permanently closed. The portfolio model goes beyond these calculations to consider the value of an aluminum plant interruption option to Bonneville or the regional power system.

The base case portfolio model simulations are less optimistic about the operation of the aluminum plants than the discrete assumptions described in the earlier section of this appendix. In 80 percent of the futures, aluminum electricity use was expected to be zero. The mean electricity demand for the plants decreased from about 100 average megawatts in the early years down to about 60 average megawatts in the later years. This compares to the medium discrete assumption of 958 average megawatts. There are futures examined in which aluminum loads vary between 800 and 1500 average megawatts although such futures are infrequent. If it were assumed that the region needed to stand ready to meet these loads, this is roughly consistent with the discrete range of DSI forecasts discussed above.

NEW DIMENSIONS OF COUNCIL DEMAND FORECASTING

Changing electricity markets are changing the planning requirements for the region. Electricity prices in the Pacific Northwest are related directly to demand and supply conditions, not just in the region, but also in the entire interconnected Western United States. In addition, electricity markets have been, and are expected to remain, volatile. Shortages and high prices will occur at specific times of the year and day depending on electricity demand, but can be prolonged in cases of poor hydroelectric conditions, such as occurred in 2001.

Evaluating electricity markets requires assumptions about demand growth in the entire West and some understanding of how the demand will vary across different seasons and across hours of the day. The following sections describe the simple approaches used to develop assumptions about future patterns of electricity consumption and predicted growth in demand throughout the rest of the West.

Patterns of Regional Electricity Consumption

One approach to forecasting temporal patterns of demand is to use the monthly and hourly patterns from the Fourth Power Plan. In the Fourth Power Plan, the Council used an extremely detailed hourly electricity demand forecasting model to estimate hourly demand patterns in the future. That model was not used for this forecast, but the hourly patterns remain similar. Another approach is to use historical patterns of demand. In practice, these approaches do not result in significantly different monthly patterns of consumption.

Whatever typical monthly shape is used, specific months can depart from the normal pattern depending on weather. Variability in consumption patterns due to weather events were considered in the portfolio planning model that addresses mitigation of risk and uncertainty in electricity markets. Typical monthly patterns provide a starting point for that analysis. The same is true for the peak demand forecast and the typical hourly patterns of demand.

Monthly Patterns of Regional Demand

Figure A-19 compares monthly patterns of regional demand in 1999 with patterns from the Council's Load Shape Forecasting System (LSFS) from the Fourth Power Plan simulation for 1995. The points on this graph indicate the monthly consumption of electricity compared to the annual average. These patterns have been adjusted to reflect only non-DSI demand. DSI demands, dominated by aluminum plants, tend to be seasonally flat.

The monthly patterns of both the actual and modeled demand reflect the higher electricity consumption in the winter with a secondary and smaller increase during the summer. Within that general pattern, there appear variations in specific months. The LSFS was based on a year in which there was a severe cold event in December. A particular year was chosen to design the model rather than an average over several years to preserve the variability in the load patterns. Averaging would have tended to flatten the hourly variation masking some of the potential volatility.

For purposes of this forecast, the 1999 pattern is used. Table A-6 shows the monthly demand shape in numerical terms.

Table A-6: Monthly Non-DSI Electricity Consumption Pattern

Month	Shape Factor
January	1.140
February	1.097
March	1.020
April	0.943
May	0.921
June	0.938
July	0.969
August	0.957
September	0.911
October	0.940
November	1.033
December	1.185

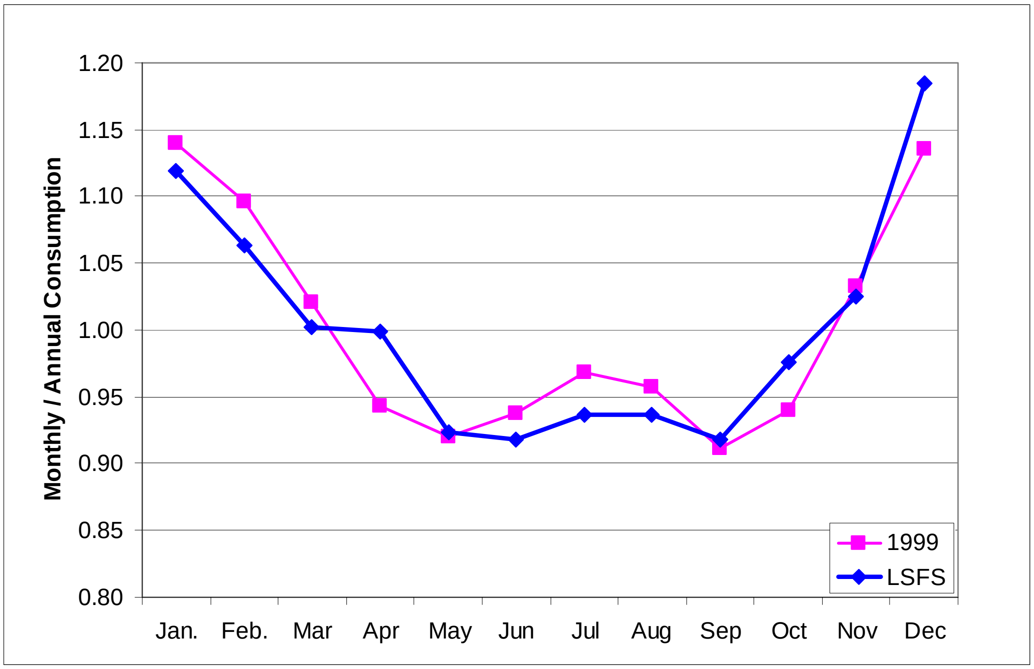

Figure A-19: Monthly Patterns of Non-DSI Electricity Use

Regional Peak Demand

Monthly regional peak demands are also taken from the Council's Load Shape Forecasting System. Figure A-20 shows average monthly consumption compared to monthly peak hour consumption. Peak demand is highest relative to average monthly demand in the winter months. For example, estimated January peak demand is 45 percent higher than the average demand for the month, whereas the peak August demand is only 21 percent higher than average August demand. The summer and winter peak demands occur at different times of the day. In June, July and August, peak demand hours are at 2:00 or 3:00 in the afternoon. The rest of the year peak demand occurs at 8:00 or 9:00 in the morning.

The ratio of average monthly demand to peak hour demand in a month is referred to as a "load factor." Over time the LSFS predicts that load factors will decline, especially during the winter months. That is, the peak hour demand will increase faster than the average monthly demand over time. Figure A-21 shows predicted load factors for 1995, 2005 and 2015 from the LSFS analysis of the Fourth Power Plan forecasts. The change in load factor is most pronounced in the winter months. Discussion with the Council's Demand Forecasting Advisory Committee indicated that utilities are experiencing increases in summer peak loads, probably due to an increasing presence of air conditioning in the region. In the future, the Council should investigate this trend further to see if the forecasted pattern needs to be modified to reflect a greater decrease in summer load factors.

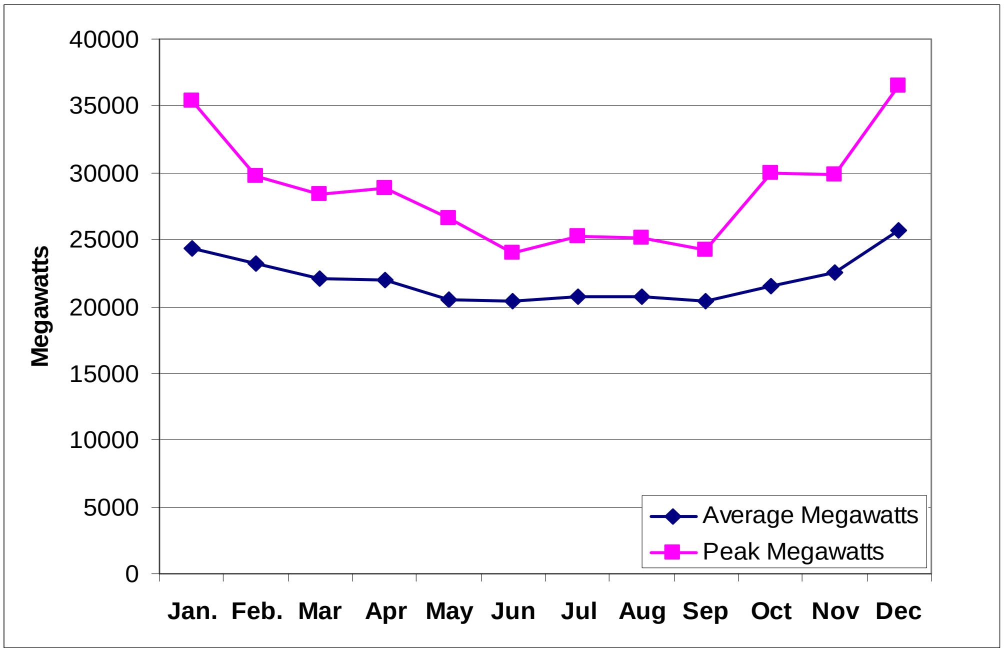

Figure A-20: Hourly Peak Demand Compared to Average Monthly Demand

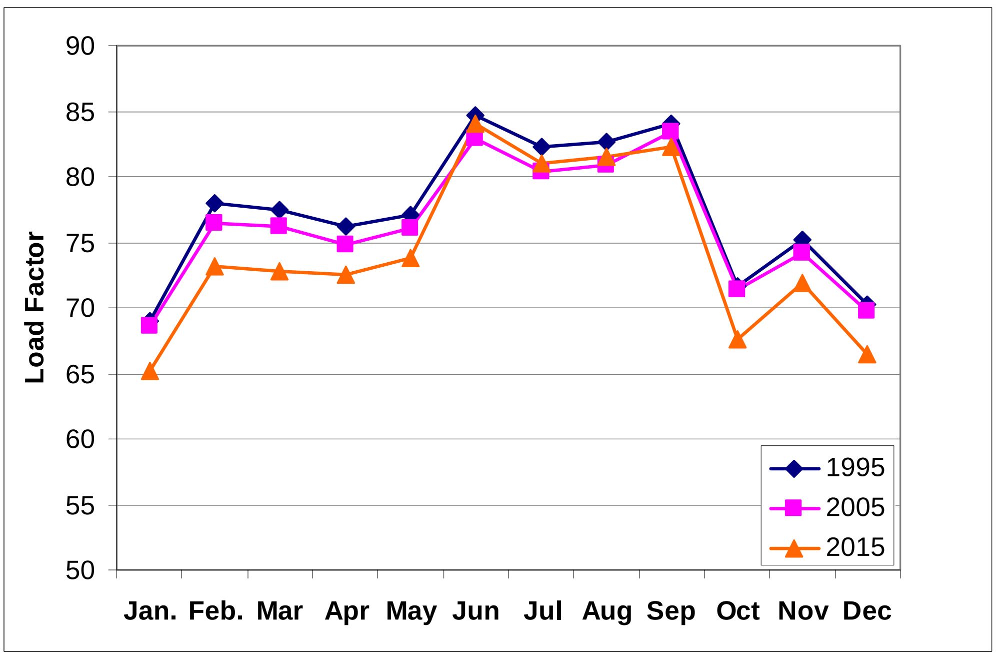

Figure A-21: Forecast of Electricity Demand Load Factors

Regional Hourly Demand Patterns

The LSFS forecasts hourly demand for 8,760 hours in the year. It does this for individual end uses within the commercial and residential sectors, for specific manufacturing sectors, and for irrigation. These hourly patterns are aggregated to obtain total hourly demand in the region. Figure A-22 illustrates hourly shapes for a typical winter weekday, a very cold winter weekday, and a summer weekday. Winter demand peaks in the morning and again in the evening. This pattern is driven largely by residential demand patterns, which are more variable across the hours of the day than the other sectors.

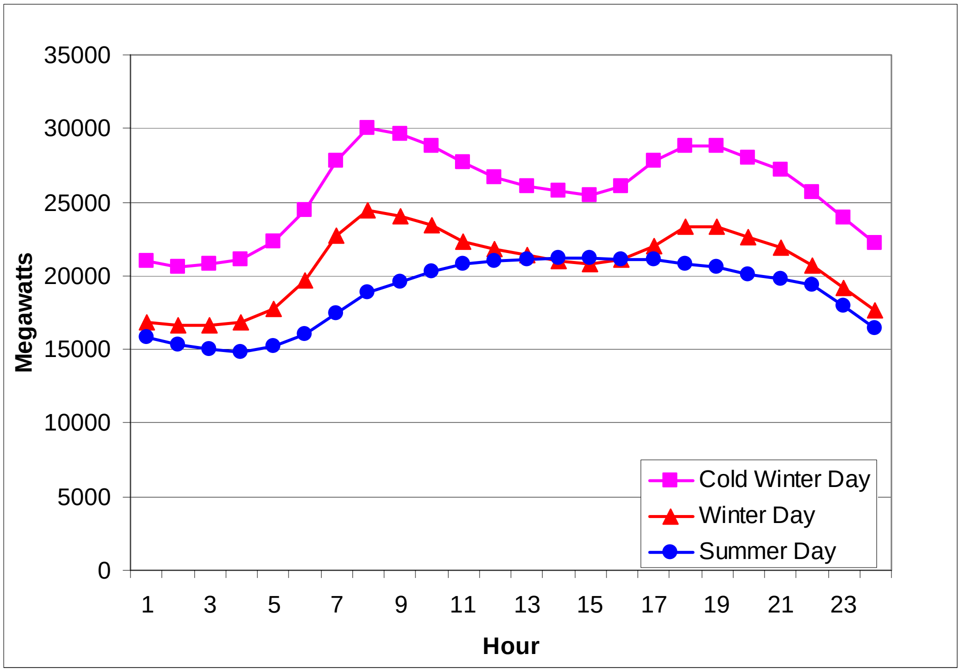

Figure A-22: Illustrative Hourly Demand Patterns in a Day

These hourly patterns of demand may be used in various ways to address analytical requirements. In the Fourth Power Plan, for example, they were aggregated into four distinct blocks of demand for a week. These included on-peak, shoulder, off-peak, and minimum load hours.[7] This was done to address sustained peaking requirements in the plan. By estimating an hourly pattern for 8,760 hours in a year, flexibility is provided to aggregate the demand patterns for different types of analysis.

Portfolio Model Analysis of Non-DSI Demand

The portfolio model goes beyond the typical demand trends and their normal seasonal and hourly patterns. It introduces random variations in loads. There are three types of variation considered. The model chooses among potential long-term trends encompassed in the range of demand forecasts discussed above as past Council plans have done. But the portfolio model also adds shorter-term excursions that reflect such events as business cycles and energy commodity price cycles, and very short-term variations such as would be caused by weather events.

Figure A-23 illustrates a few specific demand paths, from hundreds simulated, and compares them to the long-term range of non-DSI demand forecasts.

[7] See "Draft Fourth Northwest Conservation and Electric Power Plan," Appendix D, p. D-36.

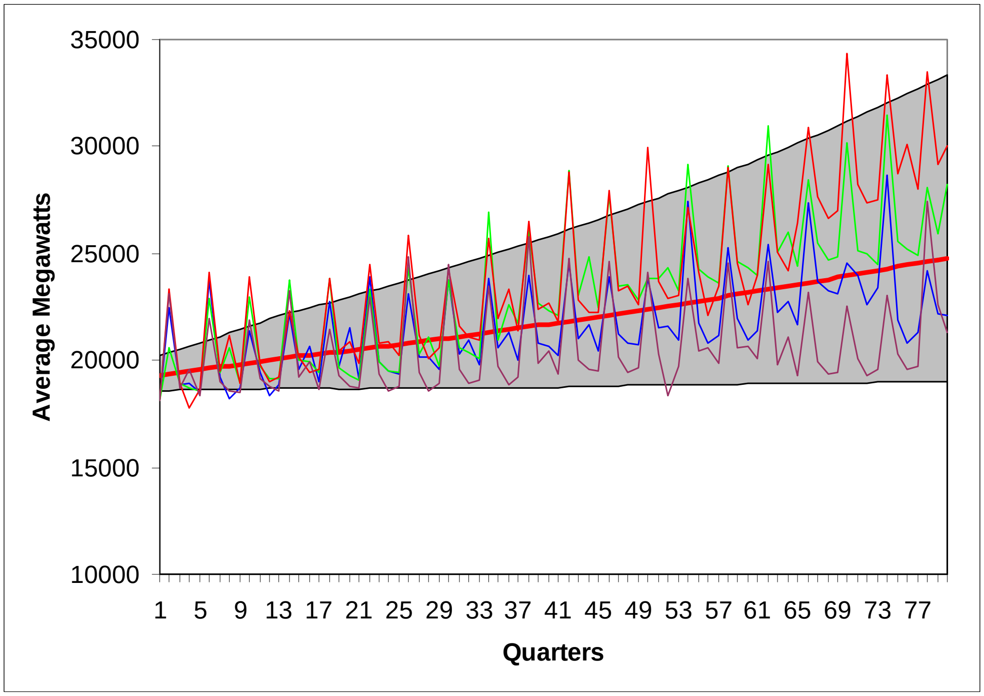

Figure A-23: Illustrative Non-DSI Demand Paths from the Portfolio Model Compared to the Trend Forecast Range

Electricity Demand Growth in the Rest of the West

In previous power plans, the Council has not concerned itself with demand growth in other parts of the West. However, as noted earlier, this is now an important consideration for analysis of future electricity prices in this region.

A simple approach was used to estimate electricity demand growth for other areas of the West. The areas used by the AURORA® electricity market model dictate the specific areas considered. The general approach used, although it varies for some areas, 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. The exceptions to this method were California, where forecasts by the California Energy Commission were used, the Pacific Northwest, and the Canadian provinces, where electricity demand forecasts were directly available from the National Energy Board.

Population forecasts for states are available from the U.S. Census Bureau web site. However, the Census forecasts were replaced by more recent state forecasts when they could be identified. For example, Nevada population forecasts were taken from the Nevada Department of Water Resources. There were two reasons for this. First, the AURORA® model distinguishes between Northern and Southern Nevada and Census forecasts were only available at the state level. Second, the Census Bureau forecast showed Nevada population growing at only .85 percent a year, whereas Nevada has recently been the fastest growing state in the nation with population growth in the neighborhood of 5 percent a year. Other population forecast sources used were the Colorado Department of Labor Affairs, the Arizona Department of Economic Security, Pacificorp's Integrated Resource Plan for Utah, and the Wyoming Department of Administration and Information.

Electricity consumption per capita varies substantially among the states in the West, as have their patterns of change over time. Figure A-24 shows electricity use per capita for Western states from 1960 to 1999. The most spectacular change is for Wyoming, which started out in 1960 with the lowest use per capita and grew to substantially higher than any other state. This may reflect significant heavy industrial growth in electricity intensive, but low employment, plants, oil and natural gas production, for example. The Pacific Northwest states are the highest per capita users of electricity, reflecting a past of very low electricity prices and a heavy presence of aluminum smelters. California is the lowest user of electricity per capita, followed by New Mexico, Utah and Colorado, which are all very similar to one another. Nevada and Arizona fall between these three states and the Pacific Northwest states.

The general pattern is substantial growth in electricity use per capita until about 1980. After 1980, most states' electricity use per capita levels off or actually declines. Exceptions to this pattern are Colorado, New Mexico, Arizona, and Utah where use per capita has slowed, but continued growing.

The Pacific Northwest was a special case. In AURORA®, the Pacific Northwest is divided into four areas; Western Oregon and Washington (west of the Cascade Mountains), Eastern Oregon and Washington combined with Northern Idaho, Southern Idaho, and Montana. The sum of these area forecasts should be consistent with the 20-year regional forecast discussed earlier. One approach would have been to share the regional demand forecast to areas based on historical shares. However, in order to recognize that areas within the Pacific Northwest have not grown uniformly, the forecast area growth rates were modified to reflect historical relative population growth in the four areas while maintaining consistency with the total regional population growth.

Table A-7 shows the forecast growth rates for the AURORA® demand areas. They are average annual growth rates from 2000 to 2025.

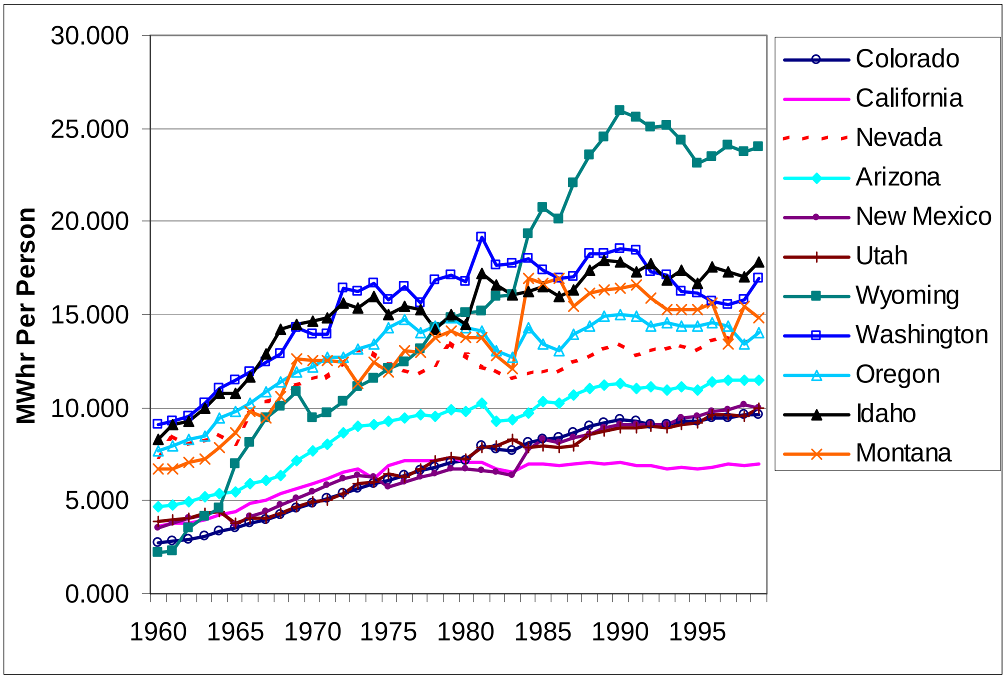

Figure A-24: State Electricity Use Per Capita: 1960 to 1999

Table A-7: Forecast Electricity Demand Growth Rates for Western Demand Areas

Area	Annual Growth Rate
PNW Western OR+WA	1.06
PNW Eastern OR+WA and Northern ID	0.42
PNW Southern ID	1.50
PNW MT	0.63
Northern CA	1.51
Southern CA	1.62
Northern NV	2.12
Southern NV	2.72
WY	0.62
UT	2.80
CO	2.34
NM	3.05
AZ	2.47
Alberta	1.59
British Columbia	1.39

FUTURE FORECASTING METHODS

At the time the Council was formed, growth in electricity demand was considered the key issue for planning. The region was beginning to see some slowing of the historically rapid growth of electricity use, and the future of several proposed nuclear and coal generating plants was in question. It was important for the Council's Demand Forecasting System (DFS) to determine the causes of changing demand growth and the extent and composition of future demand trends. Simple historical trends were no longer reliable. In addition, the requirement of the Northwest Power Act for a balanced consideration of both conservation and new generation placed another requirement on the DFS; it needed to support the detailed evaluation of improved efficiency opportunities and their effects on electricity demand.

These analytical requirements necessitated an extremely detailed approach to demand forecasting. Rather than identifying trends in aggregate or electricity consumption by sector, the Council developed a forecasting system that built demand forecasts from the end-use details of each consuming sector (residential, commercial, industrial). Forecasting with these models required detailed economic forecasts for all the sectors represented separately in the demand models. The models also required forecasts of demographic trends, electricity prices and fuel prices.

Before the last power plan update, a significant new component was added to the DFS. As Western electricity systems became more integrated through deregulated wholesale markets, and as capacity issues began to arise in the region, it became clear that we needed to understand the patterns of electricity demand over seasons, months and hours of the day. Therefore the Load Shape Forecasting System (LSFS) was developed. This model builds up the hourly shape of demand based on the underlying hourly shapes of electricity use by the different types of end-use equipment. It contains about the same detail as the DFS, but when multiplied by 8,760 hours per year, a one-year forecast can contain 400 million values.

The detailed approaches of the DFS and LSFS are expensive and time consuming. Major efforts are involved in collecting detailed end-use data, building the models, and maintaining and operating the systems. Neither the current planning issues, nor the available data and resources seem to support the continued use of the old demand forecasting approach. The Council developed an issue paper on forecasting methods in May 2001 to explore alternative approaches.[8] It was agreed that it was not possible for the Council to employ the forecasting models for the Fifth Power Plan. However, there was little consensus in the region about what changes should be made to the forecasting system for future Council planning.

The basic priorities for a demand forecast have changed. Although the Northwest Power Act still requires a 20-year forecast of demand, there are few decisions that need to be made today to meet growing electricity demands beyond the next five years. The lead-time required to put new generating resources in place has been reduced substantially from the large scale nuclear and coal plants that appeared to be desirable in the early 1980s. In addition, the restructuring of the wholesale electricity markets to rely more on competitively developed supplies means there is a less clear role for the Council's planning which focused on the type and timing of new resources to be acquired.

The focus of the Council's power activity has shifted to the evaluation of the performance of more competitive power markets and how to acquire conservation in the new market. The Council also has been concerned about the likelihood of competitive wholesale power markets

[8] Northwest Power Planning Council. "Council Demand Forecasting Issues." May 2001, Council document number 2001-13. http://www.nwcouncil.org/library/2001/2001-13.htm

providing adequate and reliable power supplies, which has three implications for demand forecasting. First, the focus is much shorter term. Adequacy and reliability depend on generating resources, including water conditions and their effects of hydroelectric generation, compared to loads. The question facing the region recently has been whether there is adequate capacity and energy to meet the coming winter demand. Second, the region is no longer independent of the entire Western U.S. electricity market. Electricity prices and adequacy of supply are now determined by West-wide electricity conditions. The AURORA® electricity market model that the Council is using requires assumptions about demand growth for all areas of the Western integrated electricity grid. Third, the temporal patterns of demand and peak demands matter more. The region is becoming more likely to be constrained by sustained peaking capability than average annual energy supplies, as it was in the past. Further, the rest of the West has always been capacity constrained and thus peak prices throughout the West can be expected during peak demand periods.

Thus, for purposes of demand forecasting, the requirements of the forecast are shifting to shorter term, temporal patterns, and expanded geographic areas. This implies that a different type of demand forecasting system may be useful for future Council planning. However, there remains the question of estimated potential efficiency gains in the use of electricity. To assess cost-effective conservation potential, the end-use detail of the old forecasting models would still be useful. But even if the Council still had the resources to use the old forecasting models, the detailed data necessary to update the models does not exist. Finding new ways of assessing conservation potential, or of encouraging its adoption without explicit estimates of the amount likely to be saved, is a significant issue for regional planning.

The forecasts presented in this paper are based on an extension of the previous Council plan and relatively simple approaches to expanding the geographic and temporal dimensions of the forecast. The Council needs to invest in new forecasting approaches for future power plans. One of the activities for the Council over the next several years will be to develop a new forecasting system that is better oriented to the available Council resources, to the current planning issues, and to the available data regarding electricity consumption and its driving variables. The Council welcomes suggested approaches and advice in this area.

Fifth Power Plan Demand Forecast D2
Medium Case

	2000 (Actual)	2005	2010	2015	2020	2025	Growth Rates 2000-2025	2000-2015	2005-2025
Total Sales	20080	19391	20646	22105	23701	25423	0.95	0.64	1.36
Non-DSI Sales	17603	18433	19688	21147	22742	24464	1.33	1.23	1.43
Residential	6724	7262	7687	8230	8809	9430	1.36	1.36	1.31
Commercial	5219	5453	5771	6146	6556	6993	1.18	1.10	1.25
Non-DSI Industrial	4836	4904	5397	5919	6505	7150	1.58	1.36	1.90
DSI Industrial	2477	958	958	958	958	958	-3.73	-6.13	0.00
Irrigation	652	629	641	654	667	681	0.17	0.02	0.40
Other	172	185	191	198	204	211	0.82	0.93	0.66

Total

	2000 (Actual)	2015	2025	Growth Rates 2000-2015	2000-2025
Low	20080	17489	17822	-0.92	-0.48
Medium Low	20080	19942	21934	-0.05	0.35
Medium	20080	22105	25423	0.64	0.95
Medium High	20080	24200	29138	1.25	1.50
High	20080	27687	35897	2.16	2.35

Non-DSI

	2000 (Actual)	2015	2025	Growth Rates 2000-2015	2000-2025
Low	17603	17489	17822	-0.04%	0.05%
Medium Low	17603	19482	21474	0.68%	0.80%
Medium	17603	21147	24464	1.23%	1.33%
Medium High	17603	23000	27937	1.80%	1.86%
High	17603	26187	34397	2.68%	2.72%

Total Demand

Weather Adjusted Sales Actual	YEAR	Revised Forecast Low	Medlo	Medium	Medhi	High
15533	1981					
14767	1982					
14448	1983					
15477	1984					
15194	1985					
15352	1986					
15872	1987					
16683	1988					
17356	1989					
17549	1990					
17903	1991					
17994	1992					
18021	1993					
18385	1994					
18647	1995					
19099	1996					
19685	1997					
19967	1998					
20487	1999					
20082	2000			20080		
17235	2001			17415		
	2002			17565		
	2003			18145		
	2004			18714		
	2005	17191	18284	19391	20220	21721
	2006	17200	18415	19621	20560	22227
	2007	17214	18558	19864	20921	22757
	2008	17228	18699	20103	21294	23314
	2009	17257	18858	20363	21679	23897
	2010	17297	19030	20646	22079	24507
	2011	17320	19189	20917	22476	25098
	2012	17353	19366	21209	22897	25714
	2013	17366	19527	21480	23307	26343
	2014	17430	19734	21789	23748	27001
	2015	17489	19942	22105	24200	27687
	2016	17522	20132	22415	24649	28406
	2017	17554	20324	22729	25108	29145
	2018	17586	20518	23048	25576	29907
	2019	17619	20714	23372	26053	30690
	2020	17652	20913	23701	26541	31497
	2021	17686	21113	24035	27039	32327
	2022	17719	21315	24374	27547	33181
	2023	17753	21519	24718	28066	34060
	2024	17787	21725	25068	28596	34966
	2025	17822	21934	25423	29138	35897
Growth Rate	2005-25	0.18%	0.91%	1.36%	1.84%	2.54%
Growth Rate	2000-25	-0.48%	0.35%	0.95%	1.50%	2.35%

Total Non-DSI Demand

Weather Adjusted Sales Actual	YEAR	Revised Forecast Low	Medlo	Medium	Medhi	High
13085	1981					
12774	1982					
12588	1983					
13019	1984					
13126	1985					
13467	1986					
13807	1987					
14248	1988					
14825	1989					
15084	1990					
15496	1991					
15653	1992					
15756	1993					
16310	1994					
16589	1995					
16519	1996					
16871	1997					
17034	1998					
17464	1999					
17605	2000			17603		
	2001			17129		
	2002			17152		
	2003			17545		
	2004			18072		
	2005	17191	17824	18433	19020	20221
	2006	17200	17955	18663	19360	20727
	2007	17214	18098	18906	19721	21257
	2008	17228	18239	19145	20093	21814
	2009	17257	18398	19405	20479	22397
	2010	17297	18570	19688	20879	23007
	2011	17320	18729	19959	21275	23598
	2012	17353	18906	20251	21696	24214
	2013	17366	19067	20521	22106	24843
	2014	17430	19274	20830	22547	25501
	2015	17489	19482	21147	23000	26187
	2016	17522	19672	21456	23449	26906
	2017	17554	19864	21770	23907	27645
	2018	17586	20058	22089	24375	28407
	2019	17619	20254	22413	24853	29190
	2020	17652	20453	22742	25341	29997
	2021	17686	20653	23076	25839	30827
	2022	17719	20855	23415	26347	31681
	2023	17753	21059	23760	26866	32560
	2024	17787	21265	24109	27396	33466
	2025	17822	21474	24464	27937	34397
Growth Rate	2005-25	0.18%	0.94%	1.43%	1.94%	2.69%
Growth Rate	2000-25	0.05%	0.80%	1.33%	1.86%	2.72%

Residential Demand

	Revised Forecast				
	Low	Medlo	Medium	Medhi	High
2000			6724		
2001	6397	6759	6797	6876	7093
2002	6642	6722	6784	6883	7162
2003	6857	6902	6987	7110	7462
2004	6837	7069	7183	7333	7767
2005	6728	7122	7262	7437	7955
2006	6728	7178	7340	7545	8124
2007	6735	7244	7428	7665	8305
2008	6731	7299	7505	7777	8484
2009	6734	7362	7589	7894	8673
2010	6747	7436	7687	8021	8876
2011	6768	7517	7789	8159	9077
2012	6793	7599	7896	8302	9280
2013	6801	7668	7986	8430	9472
2014	6838	7765	8103	8584	9688
2015	6878	7869	8230	8747	9918
2016	6890	7954	8343	8900	10167
2017	6902	8040	8457	9056	10423
2018	6915	8126	8573	9214	10684
2019	6927	8214	8690	9376	10952
2020	6940	8303	8809	9540	11227
2021	6952	8393	8930	9707	11509
2022	6965	8483	9052	9876	11798
2023	6977	8575	9176	10049	12094
2024	6990	8667	9302	10225	12398
2025	7002	8761	9430	10404	12709
Growth 2000-25	0.16%	1.06%	1.36%	1.76%	2.58%

Commercial Demand

	Revised Forecast				
	Low	Medlo	Medium	Medhi	High
2000			5219		
2001	5043	5064	5083	5184	5319
2002	5218	5240	5124	5248	5427
2003	5260	5281	5201	5348	5576
2004	5357	5377	5378	5560	5842
2005	5255	5274	5453	5670	6008
2006	5267	5306	5509	5763	6148
2007	5276	5338	5564	5858	6292
2008	5293	5378	5627	5965	6450
2009	5317	5425	5696	6075	6614
2010	5340	5472	5771	6184	6780
2011	5348	5507	5835	6284	6932
2012	5367	5558	5914	6398	7100
2013	5387	5611	5988	6514	7280
2014	5425	5676	6070	6631	7455
2015	5455	5735	6146	6743	7631
2016	5485	5795	6226	6856	7811
2017	5515	5855	6307	6972	7996
2018	5545	5916	6389	7089	8184
2019	5576	5978	6472	7209	8378
2020	5607	6040	6556	7330	8576
2021	5638	6103	6641	7454	8778
2022	5669	6166	6727	7580	8986
2023	5700	6231	6815	7707	9198
2024	5732	6295	6904	7837	9415
2025	5763	6361	6993	7969	9638
Growth 2000-25	0.40%	0.79%	1.18%	1.71%	2.48%

Industrial Non-DSI Demand

	Revised Forecast				
	Low	Medlo	Medium	Medhi	High
2000	4737	4770	4836	4833	4851
2001	4239	4303	4401	4454	4589
2002	4245	4344	4484	4567	4744
2003	4277	4411	4596	4710	4933
2004	4297	4469	4702	4850	5124
2005	4402	4616	4904	5092	5429
2006	4402	4657	4997	5225	5618
2007	4403	4700	5092	5365	5817
2008	4405	4743	5189	5511	6027
2009	4410	4789	5291	5662	6248
2010	4415	4836	5397	5818	6480
2011	4410	4878	5498	5970	6709
2012	4403	4918	5601	6128	6947
2013	4391	4957	5703	6287	7194
2014	4384	5000	5808	6453	7454
2015	4377	5044	5919	6626	7726
2016	4370	5088	6032	6803	8009
2017	4364	5133	6147	6985	8301
2018	4357	5178	6264	7172	8605
2019	4350	5224	6384	7364	8919
2020	4343	5270	6505	7561	9245
2021	4336	5316	6629	7763	9583
2022	4329	5363	6756	7970	9933
2023	4322	5410	6885	8184	10297
2024	4316	5458	7016	8403	10673
2025	4309	5506	7150	8627	11063
Growth 2000-25	-0.46%	0.52%	1.58%	2.34%	3.37%

DSI Demand

Year	Low	Medlo	Medium	Medhi	High
	Revised Forecast				
2000			2477		
2001			286		
2002			412		
2003			600		
2004			642		
2005	0	460	958	1200	1500
2006	0	460	958	1200	1500
2007	0	460	958	1200	1500
2008	0	460	958	1201	1500
2009	0	460	958	1201	1500
2010	0	460	958	1201	1500
2011	0	460	958	1201	1500
2012	0	460	958	1201	1500
2013	0	460	958	1201	1500
2014	0	460	958	1201	1500
2015	0	460	958	1201	1500
2016	0	460	958	1201	1500
2017	0	460	958	1201	1500
2018	0	460	958	1201	1500
2019	0	460	958	1201	1500
2020	0	460	958	1201	1500
2021	0	460	958	1201	1500
2022	0	460	958	1201	1500
2023	0	460	958	1201	1500
2024	0	460	958	1201	1500
2025	0	460	958	1201	1500
Growth 2000-25		-6.5%	-3.7%	-2.9%	-2.0%

Irrigation Demand

Year	Revised Forecast				
	Low	Medlo	Medium	Medhi	High
2000			652		
2001			690		
2002			600		
2003	593	598	600	606	610
2004	618	623	625	632	638
2005	621	626	629	636	643
2006	617	627	631	640	649
2007	613	628	634	645	656
2008	609	630	636	652	664
2009	606	632	639	658	672
2010	603	633	641	664	680
2011	600	635	644	670	687
2012	596	636	646	675	695
2013	592	636	649	679	701
2014	587	637	652	683	707
2015	582	636	654	687	713
2016	577	636	657	690	719
2017	572	636	659	694	726
2018	568	636	662	698	732
2019	563	636	665	702	738
2020	558	635	667	705	744
2021	554	635	670	709	751
2022	549	635	673	713	757
2023	544	635	675	717	763
2024	540	635	678	721	770
2025	535	635	681	725	777
Growth 2000-25	-0.79%	-0.11%	0.17%	0.42%	0.70%

Other

Year	Low	Medlo	Medium	Medhi	High
	Revised Forecast				
2000			172		
2001			158		
2002			160		
2003			160		
2004			184		
2005	185	185	185	185	185
2006	186	186	186	186	186
2007	188	188	187	188	188
2008	189	189	189	189	189
2009	190	190	190	190	190
2010	191	191	191	191	191
2011	193	193	193	193	193
2012	194	194	194	194	194
2013	195	195	195	195	195
2014	197	197	196	197	197
2015	198	198	198	198	198
2016	199	199	199	199	199
2017	201	201	200	201	201
2018	202	202	202	202	202
2019	203	203	203	203	203
2020	205	205	204	205	205
2021	206	206	206	206	206
2022	207	207	207	207	207
2023	209	209	208	209	209
2024	210	210	210	210	210
2025	211	211	211	211	211
Growth 2000-25	0.83%	0.83%	0.82%	0.83%	0.83%