Appendix C: Demand Forecast

ENERGY DEMAND

Background

It has been 26 years, a mere generation, since the Council released its first power plan in 1983. Since then, the region's energy environment has undergone many changes. In the decade prior to the Northwest Power Act, regional electricity load was growing at 3.5 percent per year and load (excluding the direct service industries) grew at an annual rate of 4.3 percent. In 1970, regional load was about 11,000 average megawatts, and during that decade demand grew by about 4,700 average megawatts. During the 1980s, load growth slowed significantly but continued to grow at about 1.5 percent per year, experiencing load growth of about 2,300 average megawatts. In the 1990s, another 2,000 average megawatts was added to the regional load, making load growth in the last decade of 20th century about 1.1 percent. Since 2000, regional load has declined. As a result of the energy crisis of 2000-2001 and the recession of 2001-2002, regional load decreased by 3,700 average megawatts between 2000 and 2001. Loss of many of the aluminum and chemical companies that were direct service industries contributed to this load reduction. Since 2002, however, regional load has been on an upswing, growing at an annual rate of 2.5 percent. This growth has been driven by increasing demand from commercial and residential sectors. Figure C-1 and Table C-1 track the regional electricity sales from 1970-2007.

Figure C-1: Total and Non-DSI Regional Electricity Sales (MWa)

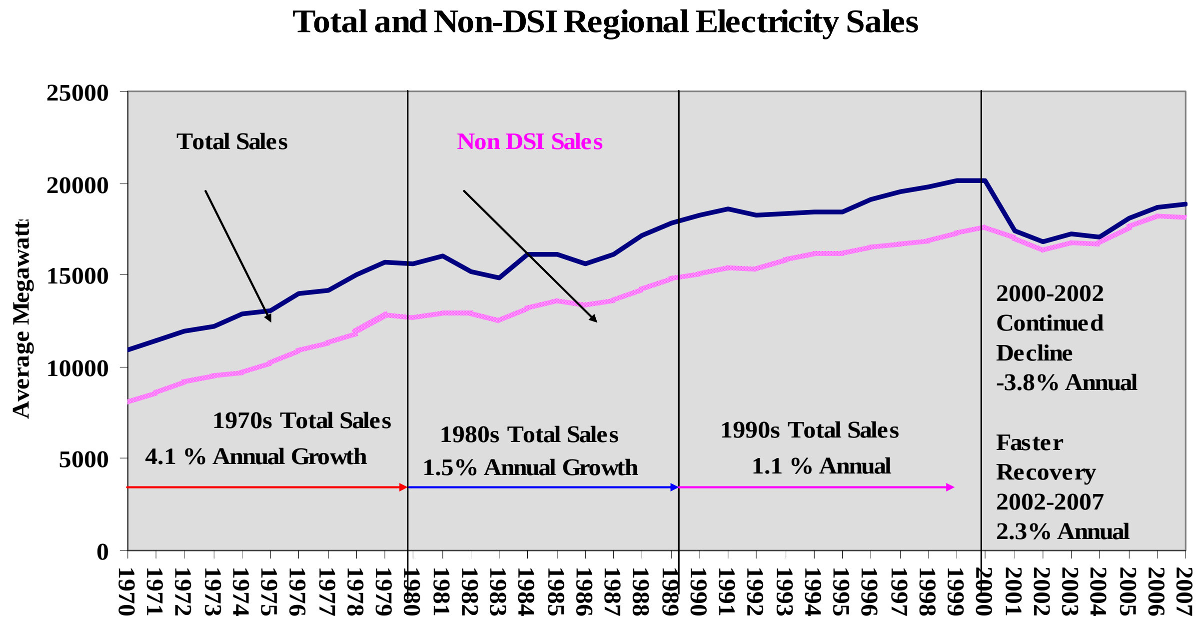


Table C-1: Total and Non-DSI Regional Electricity Sales

Annual Growth	Total Sales	Non DSI
1970-1979	4.1%	5.2%
1980-1989	1.5%	1.7%
1990-1999	1.1%	1.5%
2000-2007	-0.8%	0.5%
2002-2007	2.5%	2.2%

The dramatic decrease in the growth of electricity demand shown in Table C-1 was not due to a slowdown in economic growth in the region. The region added more population and more jobs between 1980 and 2000 than it did between 1960 and 1980. The decrease in demand was the result of a move to less energy-intensive activities. As shown in Table C-2, electric intensity in terms of use per capita increased between 1980 and 1990, but has been declining since 1990. This shift reflects industry changes, increasing electricity prices, and regional and national conservation efforts.

Table C-2: Changing Electric Intensity of the Regional Economy

Year	Non-DSI Electricity Use Per Capita (MWa / Thousand Persons)
1985	1.50
1990	1.57
2000	1.52
2007	1.45

For the most part, the upswing in load since 2002 has been due to growth in residential- and commercial-sector sales. By the end of 2007, the residential sector had added about 888 average megawatts to load, the commercial sector 285 average megawatts, while the industrial sector lost 337 megawatts.

In the past two decades, the region's population has grown from roughly 9 million in 1985 to more than 12.6 million in 2007. This growth rate surpasses the national population growth rate by almost 40 percent. Typically, this level of increase in population would put significant pressure on the electricity demand. However, due to regional conservation investments and a shift to less energy-intensive industries, the region's demand for electricity has remained stable. For example, during the years 1990-2007, the U.S. population grew at an annual rate of 0.9 percent, while residential demand for electricity grew at 2.4 percent. In the Northwest, the average growth rate in population was 1.3 percent, while the residential demand for electricity grew at an annual rate of 1.4 percent, a full percentage point below the national average. Similar patterns can be observed in the commercial sector.

Demand Forecast Methodology

When the Council was formed, growth in electricity demand was considered the key issue for planning. The region was beginning to see some slowing of its historically rapid growth of electricity use, and it began to question the future of several proposed nuclear and coal generating plants. To respond to these changes, it was important that the Council's demand forecasting system (DFS) be able to determine the causes of changing demand growth and the extent and composition of future demand trends. Simple historical trends, used in the past, were no longer reliable indicators of future demand.

In addition, the Northwest Power Act requires the Council to consider conservation a resource, and to evaluate it along with new generation. So, the DFS analysis also needs to support a detailed evaluation of energy efficiency improvements and their effects on electricity demand.

Rather than identifying trends in aggregate or electricity consumption by sector, the Council developed a forecasting system that incorporates end-use details of each consuming sector (residential, commercial, industrial). Forecasting with these models requires detailed separate economic forecasts for all the sectors represented in the demand models. The models also required forecasts of demographic trends, electricity prices, and fuel prices.

As Western electricity systems became more integrated through deregulated wholesale markets, and as capacity issues began to emerge, it became clear that the Council needed to understand the pattern of electricity demand over seasons, months, and hours of the day. The load shape forecasting system (LSFS) was developed to do this. The model identifies what kinds of equipment are contributing to demand and how much electricity they are using, which helps build the hourly shape of demand.

These new detailed approaches of the DFS and LSFS were expensive and time consuming to develop, and were not used in the Fifth Power Plan. Although the Northwest Power Act still requires a 20-year forecast of demand, changes in the electricity industry have meant a greater focus on the short-term energy landscape. Rather than large-scale nuclear and coal plants, popular in the early 1980s, other resources that do not take as long to plan and develop are being chosen and built, so the need to analyze their impact on the power system is critical. In addition, the Council's centralized planning role is less clear as a restructured wholesale electricity market relies more on competitively developed resources.

The focus of the Council's power planning activity now includes evaluating the performance of more a competitive power market, and how the region should acquire conservation in this new market. The Council is also concerned about the ability of competitive wholesale power markets to provide adequate and reliable power supplies, which has implications for demand forecasting.

One of the most significant issues facing the region's power system today is that the pattern of electricity demand has changed. The question is not only if we have energy to meet annual demand, but whether we have adequate capacity to meet times of peak demand. The Pacific Northwest now resembles the rest of the West, which has always been capacity constrained. The region can now expect peak prices during Western peak demand periods. In response, the Sixth Power Plan is focused on shorter-term electricity demand.

Additionally, the region is no longer independent of the entire Western U.S. electricity market. Electricity prices and the adequacy of supply are now determined by West-wide electricity conditions. The Council uses the AURORA® electricity market model, which requires assumptions about demand growth for all areas of the Western-integrated electricity grid.

Given all these changes, the demand forecast needs to be able to analyze short-term, temporal patterns of demand and expanded geographic areas. As well, any forecast must address the effect of energy-efficiency improvements on the power system. Finding new ways to assess conservation potential, or to encourage its adoption without explicit estimates of the electricity likely to be saved, is a significant issue for regional planning.

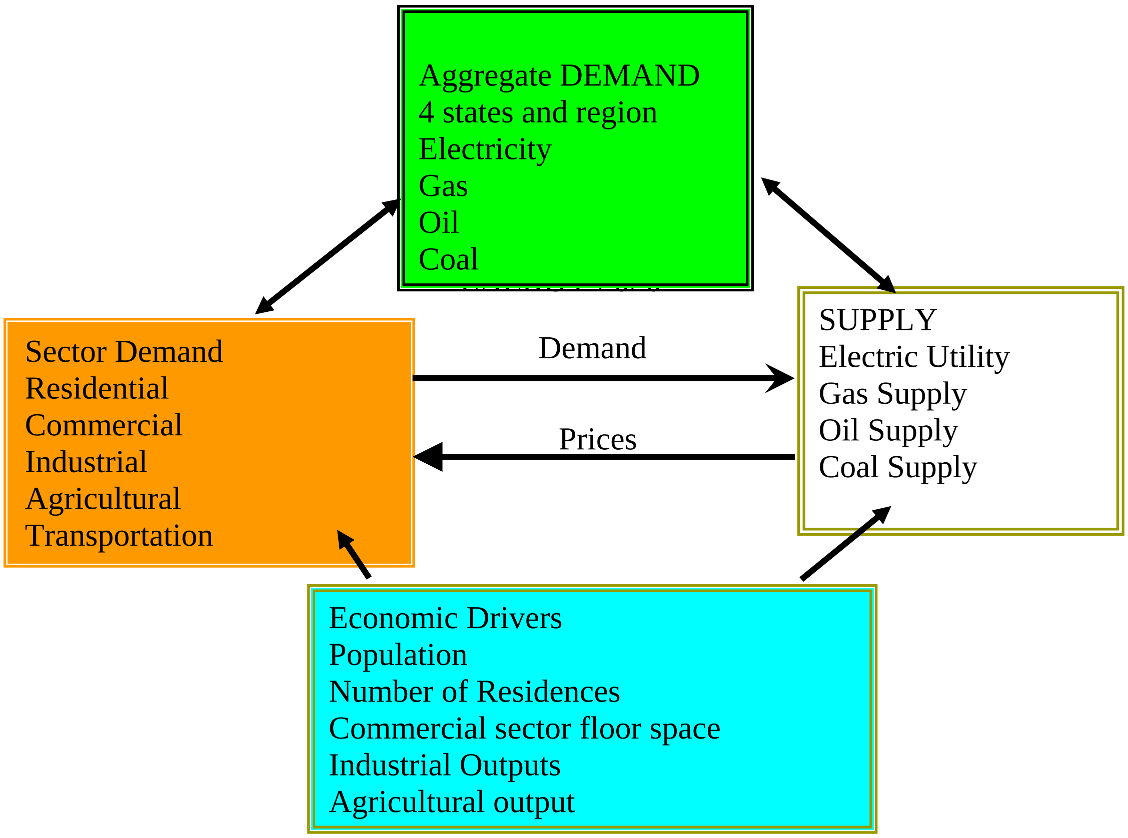
Previous Council forecasts for individual sectors have been quite accurate. The level of residential consumption was overestimated by an average of 0.6 percent. Commercial consumption was underestimated by an average of 0.9 percent, and industrial consumption, excluding direct service industries (DSI), was overestimated by an average of 3.6 percent. Long-term forecasts did not depart seriously from actual electricity consumption, so the Fifth Power Plan relied on earlier forecast trends for non-DSI electricity demand. However, the Sixth Power Plan updates the demand forecasting system.

New Demand Forecasting Model for the Sixth Plan

The 2000-2001 Western energy crisis created renewed interest in demand forecasting, and the Northwest's changing load shape has created a particular concern about capacity supply. In order to forecast these peaks, the Council relies on end-use forecasting models. For its Sixth Power Plan, the Council selected a new end-use forecasting and policy analysis tool. The new demand forecasting system (DFS), based on the Energy 2020 model, generates forecasts for electricity, natural gas, and other fuel.

The Energy 2020 model is fully integrated and includes fuel, sectors, and end-use load. The Council uses Energy 2020 to forecast annual and peak load for electricity as well as for other fuel. The following flow-chart provides an overview of the Energy 2020 model.

Figure C-2: Overview of Council's Long Term Forecasting Model



The DFS is calibrated to total demand for electricity, natural gas, oil, and a range of other fuel. The data for calibration is obtained from the Energy Information Administration's State Energy Demand System (SEDS). Annual consumption data for each sector and state is available for years 1960-2006. To add the year 2007, additional information from monthly electricity sales reports for electricity, natural gas, and oil consumption was used. The Energy 2020 model used detailed information from the previous version of the DFS to create a bridge between the old Council modeling system and the new modeling system.

The basic version of Energy 2020 was expanded to make sure that the DFS can meet the needs of conservation resource planning. The number of sectors and end-uses was increased. In the residential sector, three building types, four different space-heating technologies, and two different space-cooling technologies were tracked. Demand was tracked for electricity for 12 end-uses in the residential sector. New end-uses were added, like information, communication, and entertainment (ICE) devices, which in earlier forecasts did not have a major share of electricity consumption in homes. Technology trade-off curves were updated with new cost and efficiency data.

In the commercial sector, the model was expanded to forecast load for 18 different commercial building types. Forecasts for commercial floor space development made sure that the economic drivers of the demand forecast for electricity and the economic drivers for the conservation resource assessment were identical.

The industrial sector of the model was updated with new regional energy consumption data. The work on the industrial sector is ongoing and the results of a recent analysis on industrial demand for electricity were added to the demand forecast. The load shape forecasting system was updated with the best available data on end-use load shape to forecast peak demand, including monthly peaks. This will enable the Council to demonstrate a closer link among the demand forecasting system, the hydro modeling, and the Regional Portfolio Model (RPM).

Demand Forecast

The Council's medium or "Plan" case predicts electricity demand to grow from about 19,000 average megawatts in 2007 to 25,000 average megawatts by 2030. The average annual rate of growth over that period in this forecast is about 1.2 percent per year. This level of growth does not take into account expected demand reductions due to new conservation measures. This rate is consistent with the Council's Fifth Power Plan growth rate, which was projected to grow by 1.4 percent per year from 2000 to 2025. The winter peak demand for power is projected to grow from about 34,000 megawatts in 2010 to around 43,000 megawatts by 2030, at an average annual growth rate of 1.0 percent. The summer peak demand for power is projected to grow from 29,000 megawatts in 2010 to 40,000 megawatts by 2030, at an annual growth rate of 1.6 percent.

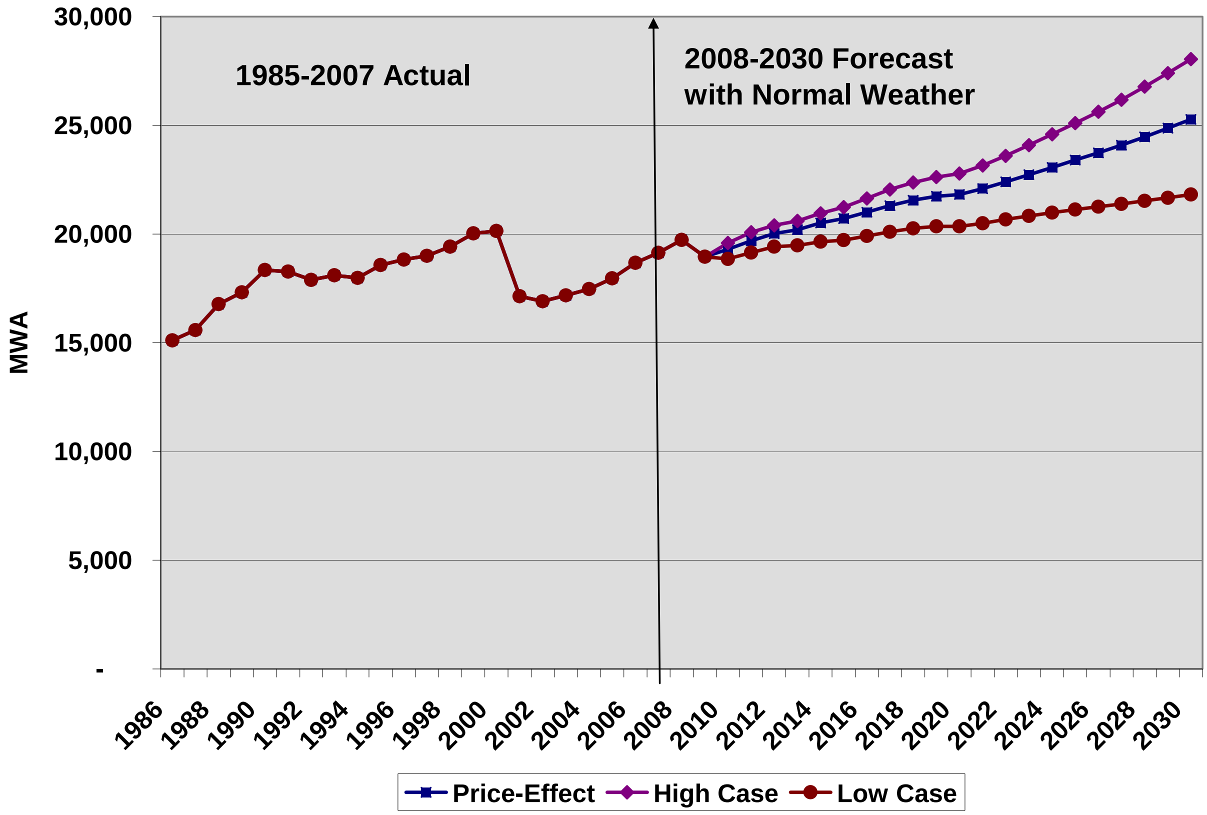
Total non-DSI consumption of electricity is forecast to grow from about 18,000 average megawatts in 2007 to over 18,600 average megawatts by 2010 and close to 25,000 average megawatts by 2030. This is an average annual growth rate of 1.4 percent for the years 2010-2030. The following table shows the forecast for each sector in the medium case. Each sector's forecast is discussed in separate subsections of this appendix.

Table C-3: Medium Case Sector Forecast of Annual Energy MWa

	2007 Actual	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2010-2030
Residential	7,424	7,499	8,335	9,987	1.06%	1.44%
Commercial	6,129	6,705	8,214	9,170	2.05%	1.58%
Industrial Non-DSI	3,904	3,724	3,715	4,360	-0.03%	0.79%
DSI	764	693	772	772	1.09%	0.54%
Irrigation	848	599	696	873	1.52%	1.90%
Transportation	71	72	87	113	1.91%	2.27%
Total Non-DSI	18,376	18,599	21,048	24,503	1.24%	1.39%
Total	19,140	19,292	21,820	25,275	1.24%	1.36%

The medium case electricity demand forecast predicts that the region's electricity consumption will grow, absent any conservation, by about 6,000 average megawatts by 2030, an average annual increase of about 270 average megawatts. The projected growth reflects increased electricity use by the residential and commercial sectors and reduced growth in the industrial sector, particularly by energy-intensive industries. Higher electricity and natural gas prices have had a tremendous impact on the region's industrial makeup. As a result of the 2000-2001 energy crisis and the recession of 2001-2002, the region lost about 3,500 megawatts of industrial demand, which it has not regained. The region is projected to surpass the 2000 level of demand by 2013. However, the depth of the 2008 recession may delay this recovery.

Figure C-3: Sixth Power Plan Range of Demand Forecasts (MWa)

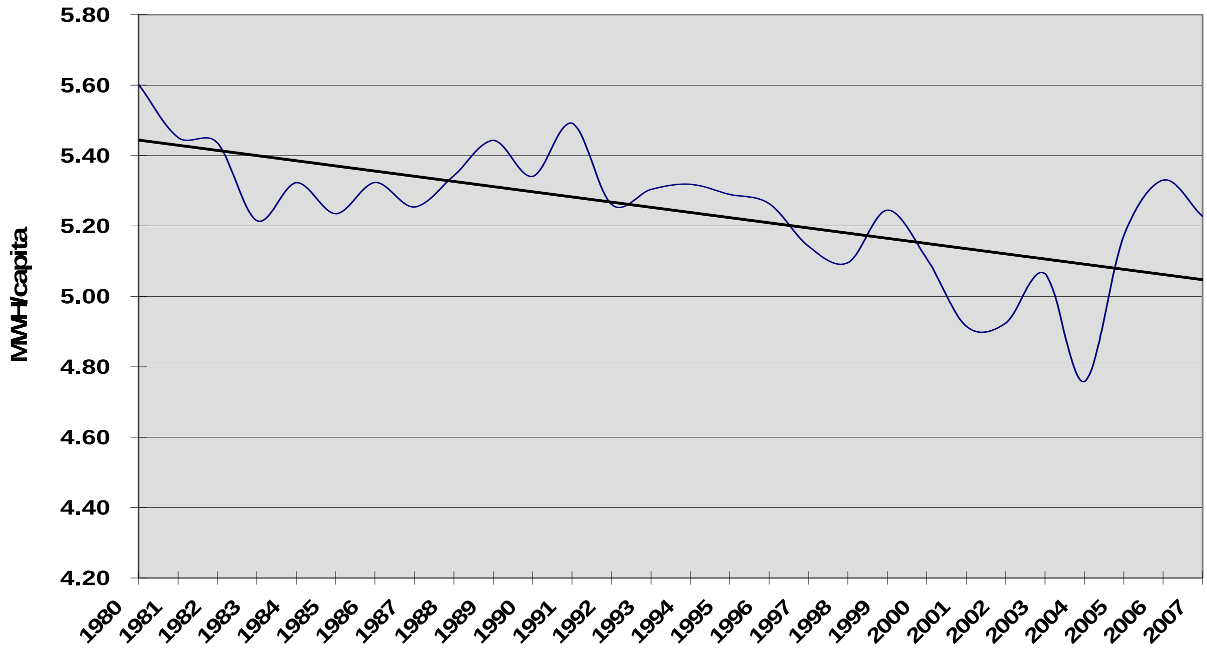


Residential Sector Demand

History

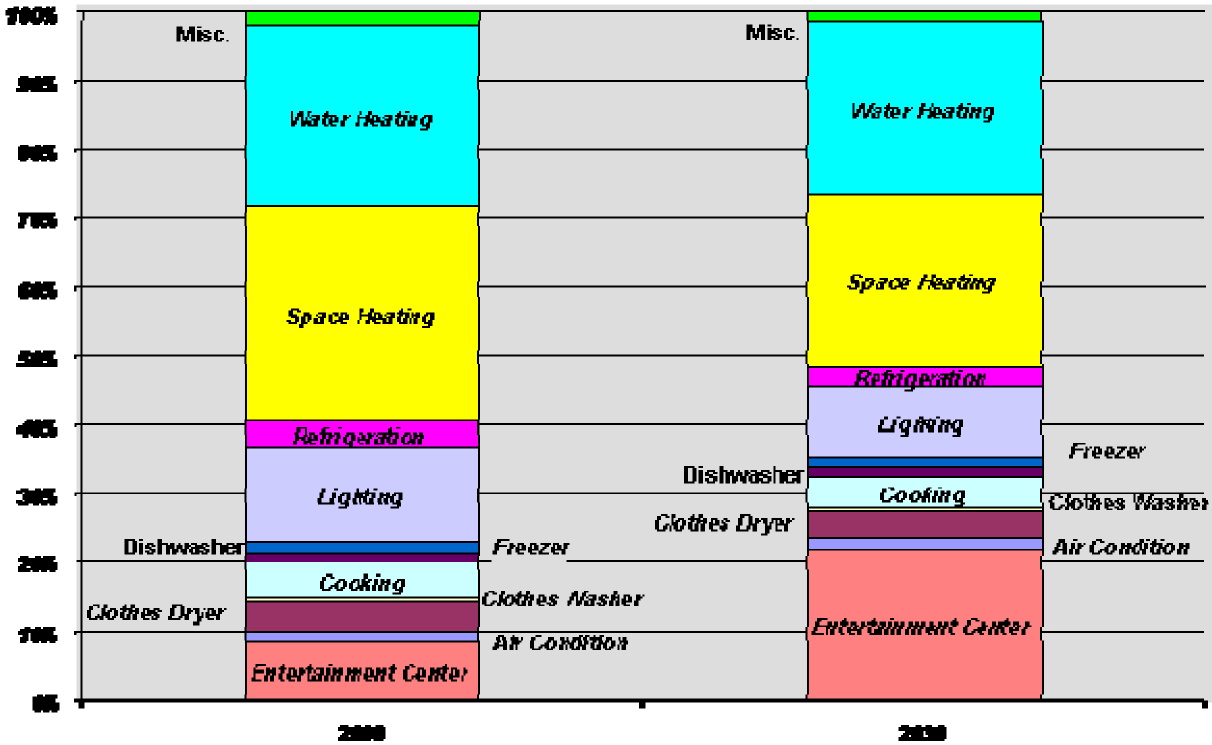
Demand for electricity in the residential sector grew from 5,350 average megawatts in 1986 to about 7,400 average megawatts in 2007. Although residential demand for electricity has been increasing, the per capita consumption of electricity in the residential sector was declining or stable until about 2005 when per capita electricity consumption began to grow. Improved building codes and more efficient appliances helped to keep the consumption level down. Per capita consumption (adjusted for weather) for the region, as well as the overall trend, is shown in the following graph.

Figure C-4: Change in Residential Per Capita Consumption



The drop in residential per capita consumption of electricity is even more significant when considering the tremendous increase in home electronics that did not even exist 25 years ago. The demand for information, communication, and entertainment (ICE) appliances has sky-rocketed and is expected to continue. The following graph shows the share of residential sector electricity consumption by end-use. The share of air-conditioning and ICE doubles between 2008 and 2030.

Figure C-5: Breakdown of Residential Electricity Consumption by End-use

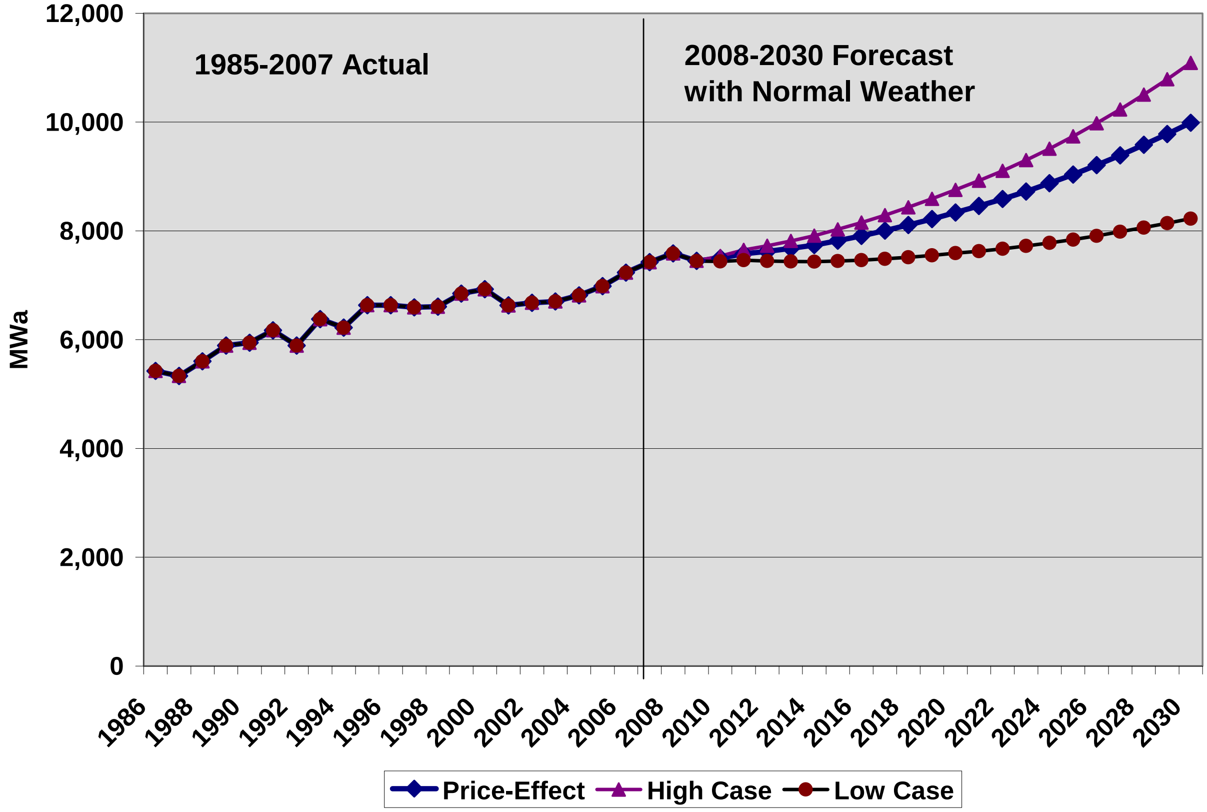


Residential Demand Forecast

For the medium case scenario, residential electricity consumption is forecast to grow by 1.4 percent between 2010 and 2030. This growth rate is consistent with the levels anticipated in the Fifth Power Plan, which estimated the growth rate for the residential sector to be 1.36 percent per year between the years 2000 and 2025. The Sixth Power Plan predicts that for 2008-2030, residential sector demand will increase by an average of about 125 megawatts per year. This forecast does not incorporate the effect of new conservation investments.

Note: There is a companion Excel workbook, available from the Council website, with the details of Sixth Power Plan load forecast.

Figure C-6: Forecast Residential Electricity Sales

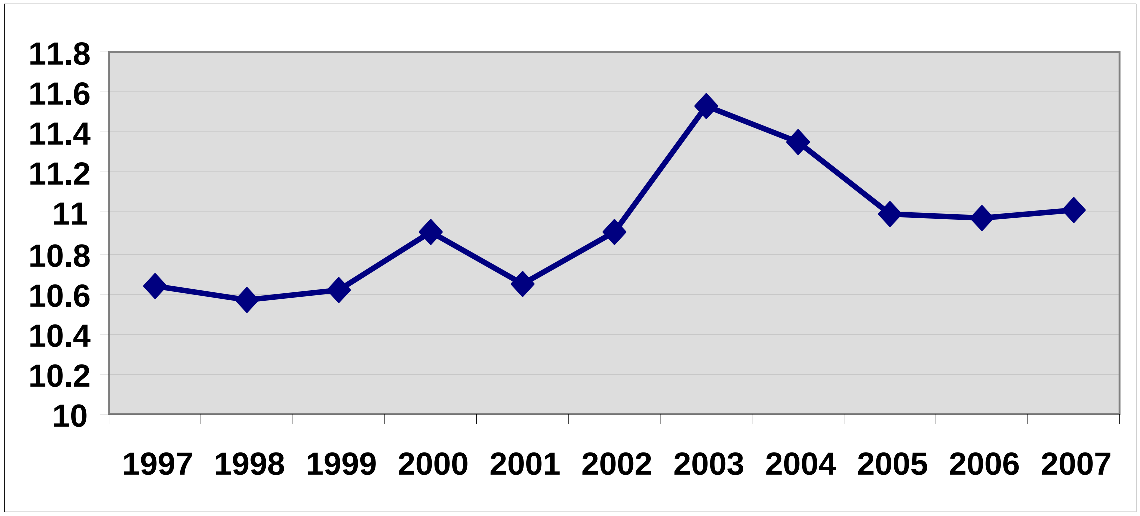


Commercial Sector Demand

History

Electricity demand in the commercial sector has increased regionally and nationally. In 1986, demand in the commercial sector of the region was about 4,000 average megawatts and by 2007 this sector required more than 6,000 average megawatts. Electricity intensity in the sector has also increased. Electricity intensity in the commercial sector is measured in kilowatt hours used per square foot. In 1997, the commercial sector's average electricity intensity was about 10.6 kilowatt hours per square foot. By 2003, it had increased to about 11.6 kilowatt hours per square foot. Since 2003, however, the intensity of electricity use in the commercial sector has been declining or has remained stable. The commercial sector also includes street lighting, traffic lights and load from municipal public facilities such as sewer treatment facilities.

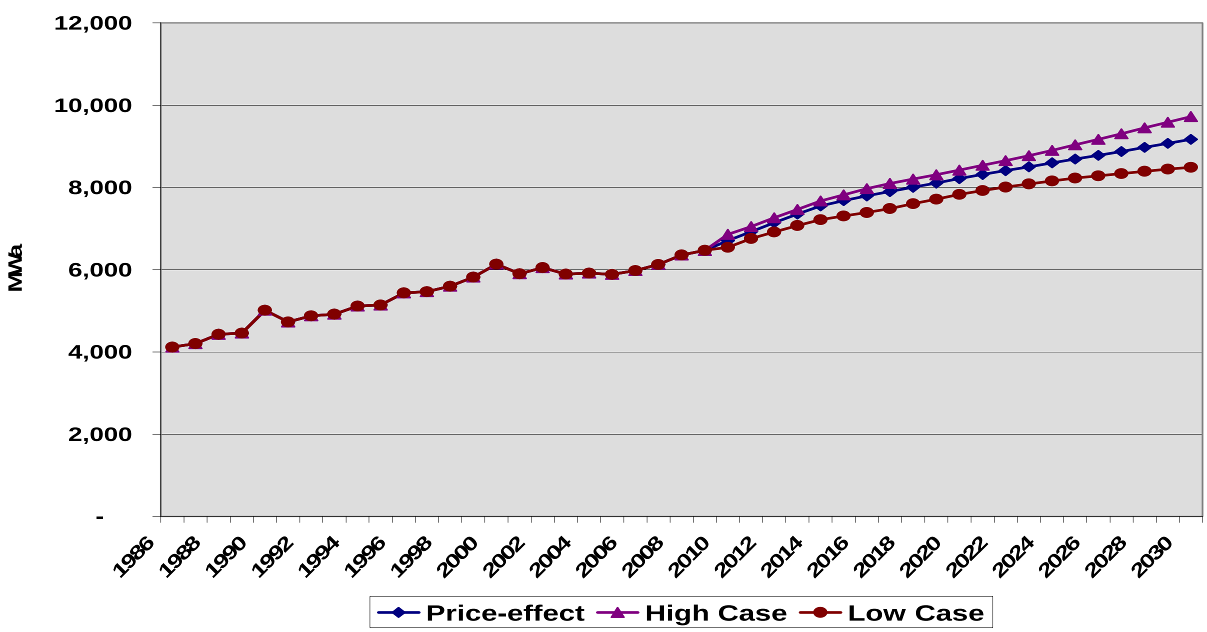
Figure C-7: Electricity Intensity in the Commercial Sector (kWh/SQF)



Commercial Demand Forecast

Commercial sector electricity consumption is forecast to grow by 1.6 percent per year between 2010 and 2030. During this period, demand is expected to grow from 6,700 average megawatts to about 9,000 average megawatts. This rate of increase is higher than the 1.18 percent per year that was forecast in the Fifth Power Plan. The following figure illustrates the forecast. On average, this sector's predicted demand adds about 110 average megawatts per year during 2010 and 2030.

Figure C-8: Forecast Commercial Electricity Sales



Non-DSI Industrial Sector

Industrial electricity demand is difficult to confidently forecast. It differs from residential and commercial sector demand where energy is used mostly for buildings and is reasonably uniform and easily related to household growth and employment. By contrast, industrial electricity use is extremely varied, and demand tends to be concentrated in relatively few very large, often specialized, uses instead of spread among many relatively uniform uses.

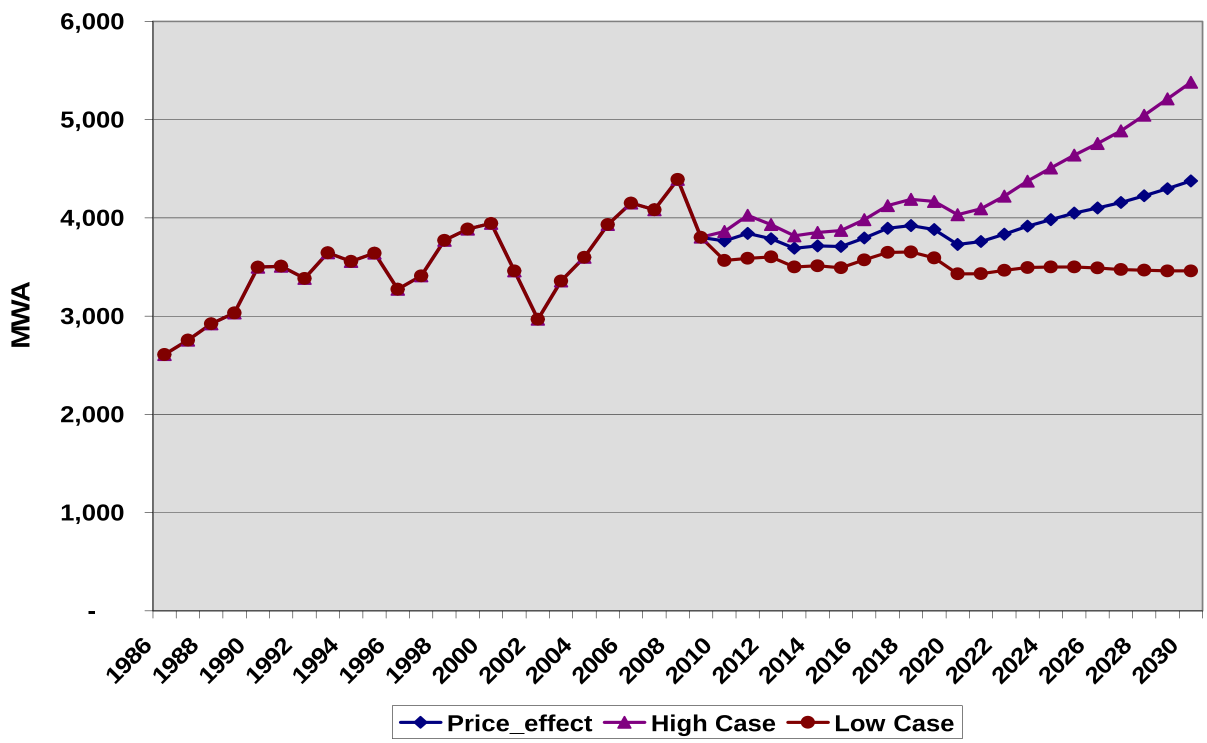
The non-DSI industrial sector demand is dominated by pulp and paper, food processing, chemical, primary metals other than aluminum, and lumber and wood products industries. Many of these industries have declined or are experiencing slow growth. These traditional resource-based industries are becoming less important to regional electricity demand forecasts, while new industries, such as semiconductor manufacturing, are growing faster and commanding a growing share of the industrial-sector load.

In the Sixth Power Plan, non-DSI industrial consumption is forecast to grow at 0.8 percent annually. Electricity consumption in this sector is forecast to grow from 3,900 average megawatts in 2007 to 4,360 in 2030. The non-DSI industries' demand peaked in 1999 reaching 4,000 average megawatts. Starting with the 2000-2001 energy crisis and the recession that followed, non-DSI consumption went down to about 3,700 average megawatts by the start of 2008.

Table C-4: Changing Electric Intensity of Industries in the Northwest

Year	Non-DSI Electricity Intensity (MWh/Industrial employees)
1985	59.2
1990	58.3
2000	56.4
2002	48.7
2007	46.8

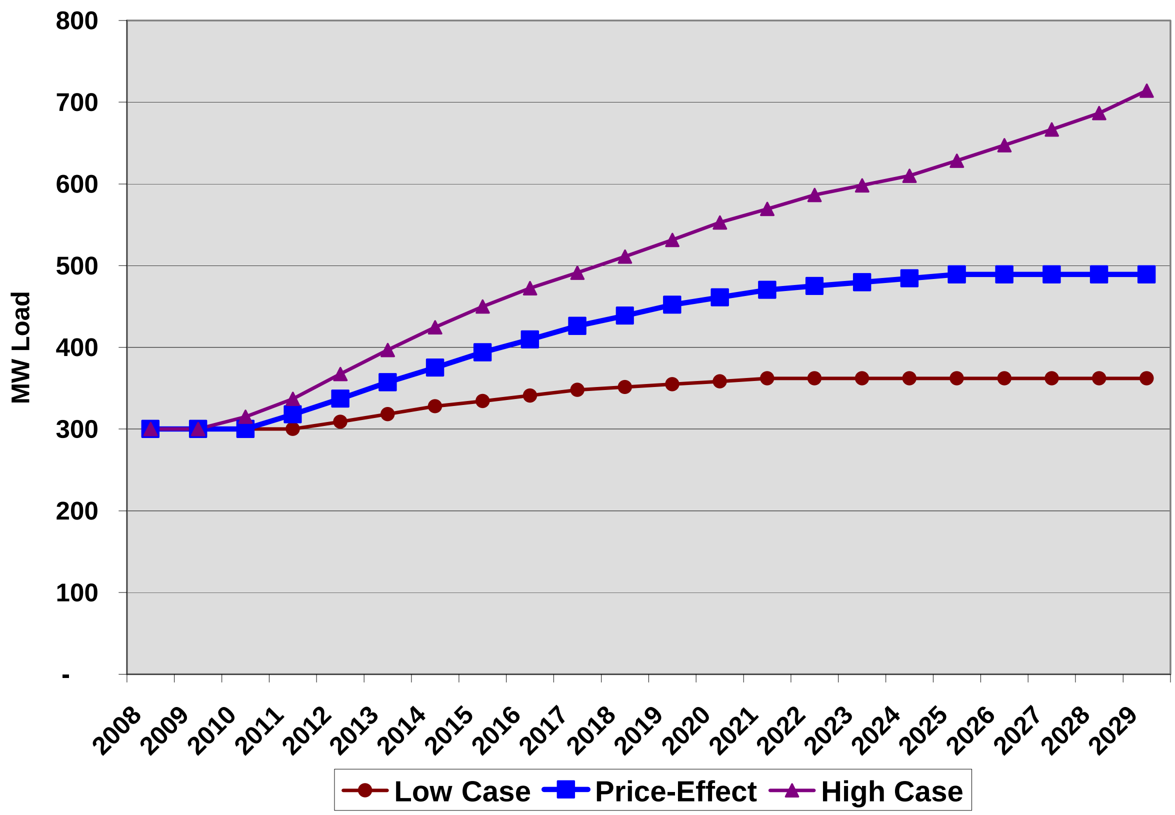
Figure C-9: Forecast Industrial Non-DSI Electricity Sales



Custom Data Centers

The non-DSI industrial load sector includes custom data centers. These centers are also known as data "farms" and "service centers" and support Internet services like the well-known Amazon.com or Google.com. These businesses do not manufacture a tangible product, but because they are typically on an industrial rate schedule and because of their size, they are categorized as industrial load. The region currently provides about 300 average megawatts to these types of businesses. The demand for services from this sector is forecast to increase by about 7 percent per year. However, there are many opportunities to increase energy efficiency in custom data centers. As a result, the demand forecast for these centers is adjusted to an annual growth rate of about 3 percent. Background and additional assumptions on custom data centers are presented at the end of this appendix.

Figure C-10: Projected Load (MW) from Custom Data Centers

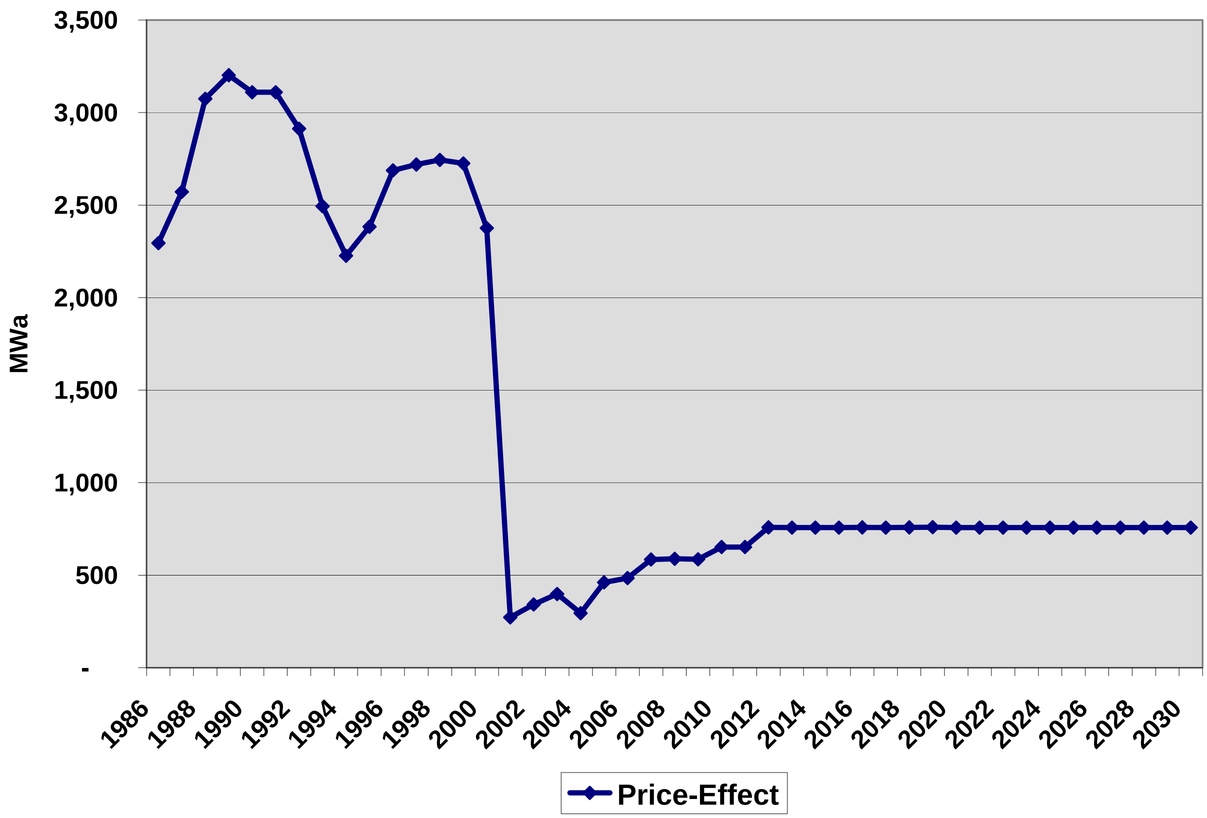


Aluminum (DSIs)

Historically, direct service industries (DSIs) have been industrial plants that purchased their electricity directly from the Bonneville Power Administration. They have played an integral role in the development of the region's hydroelectric system, for this industrial sector grew as the region's hydroelectric system grew. The vast majority of companies in this category are aluminum smelters. When all of the region's 10 aluminum smelters were operating at capacity, they could consume about 3,150 average megawatts of electricity. However, after the power crisis of 2000-2001, many smelters shut down permanently. Currently, only a few pot lines operate in the region, consuming about 750 megawatts of power. In the Fifth Power Plan, the Council developed models to forecast electricity consumption by DSI customers. In the Sixth

Power Plan, a simplified forecast assumes that DSI consumption will be around 600-700 average megawatts for the forecast period. Although the portion of Alcoa's Wenatchee aluminum smelter that is served from non-BPA sources is not technically a DSI (it is not served by BPA), that load is included in the DSI category for convenience in the Sixth Power Plan.

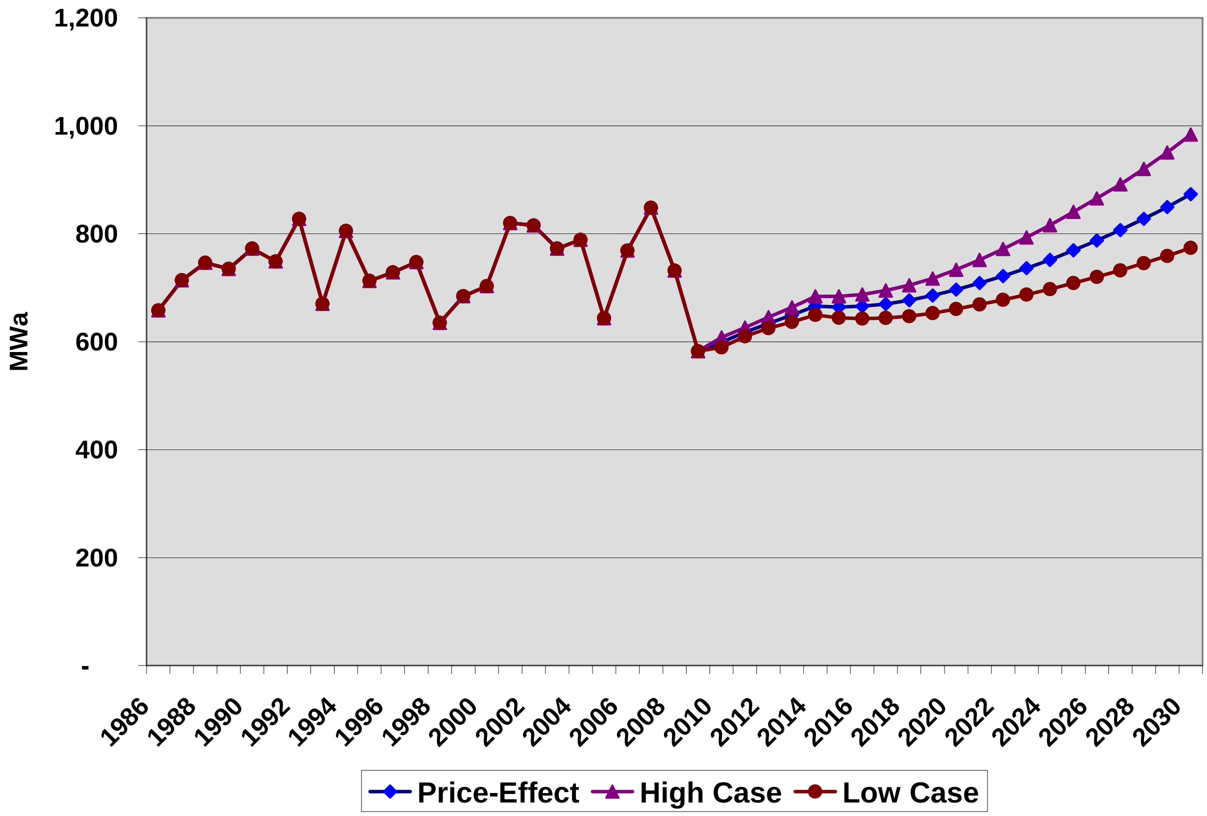
Figure C-11: Forecast DSI Electricity Sales



Irrigation

Regional irrigation load is relatively small compared to the residential, commercial, and industrial sectors. Irrigation averaged about 740 average megawatts per year between 1986 and 2007 with little trend development discernable among the wide fluctuations that reflect year-to-year weather and rainfall variations. The electricity consumption in this sector is forecast to grow at 1.9 percent annually for the forecast period, above its historic 1986-2007 growth rate. The main factor influencing demand for irrigation is precipitation. The main economic driver for this sector is the demand for agricultural products requiring irrigation. Agricultural output is forecast to grow at an average annual rate of 3-4 percent in the 2010-2030 period. Demand for electricity for food product manufacturing (fruits, meats, and dairy) is included in the industrial sector forecast.

Figure C-12: Irrigation Class, Electricity Sales



The historic growth rate for the years 1986-2007 was about 1.2 percent per year. If projected increases in summer temperatures are realized, the need for irrigation to support agricultural crops could increase.

Regional data on irrigation load has been difficult to obtain. An action item for the Sixth Power Plan might be to establish a reporting mechanism to the Council so that irrigation loads can be followed more frequently and accurately.

Transportation Demand

The use of electricity in the transportation sector, consisting mainly of mass transit systems in major metropolitan cities in the region, typically has been estimated to be about 60 average megawatts. The forecast growth rate for transportation sector is about 2.3 percent per year. The plug-in electric vehicle could be a growing segment of this sector. The Council's preliminary analysis indicates that demand from plug-in electric vehicles could add 100-550 average megawatts to regional electricity use. In the sensitivity section of the Sixth Power Plan, the effect of plug-in electric vehicles is included in the analysis.

Demand History and Forecast by State

In the past, the Council's demand forecast was available at the regional level. In the Sixth Power Plan, state-level forecasts are also available. A brief review of the historic growth rate and forecast growth rate for each state is presented in the following graph and table. Demand has been growing faster in Oregon and Idaho compared to Washington and Montana. The 2000-

2001 energy crisis and the closure of DSIs in Washington, Montana, and Oregon caused a substantial drop in industrial load. Residential demand for electricity has been growing at an average annual rate of 1.4-2.2 percent per year. Commercial demand has been growing at 0.4-2.2 percent per year. Industrial demand has had a negative growth rate in all states except Idaho. Idaho industrial load has been growing at 2.7 percent per year in the 1986-2007 period.

Figure C-13: Historic and Forecast Demand for Electricity (MWa)

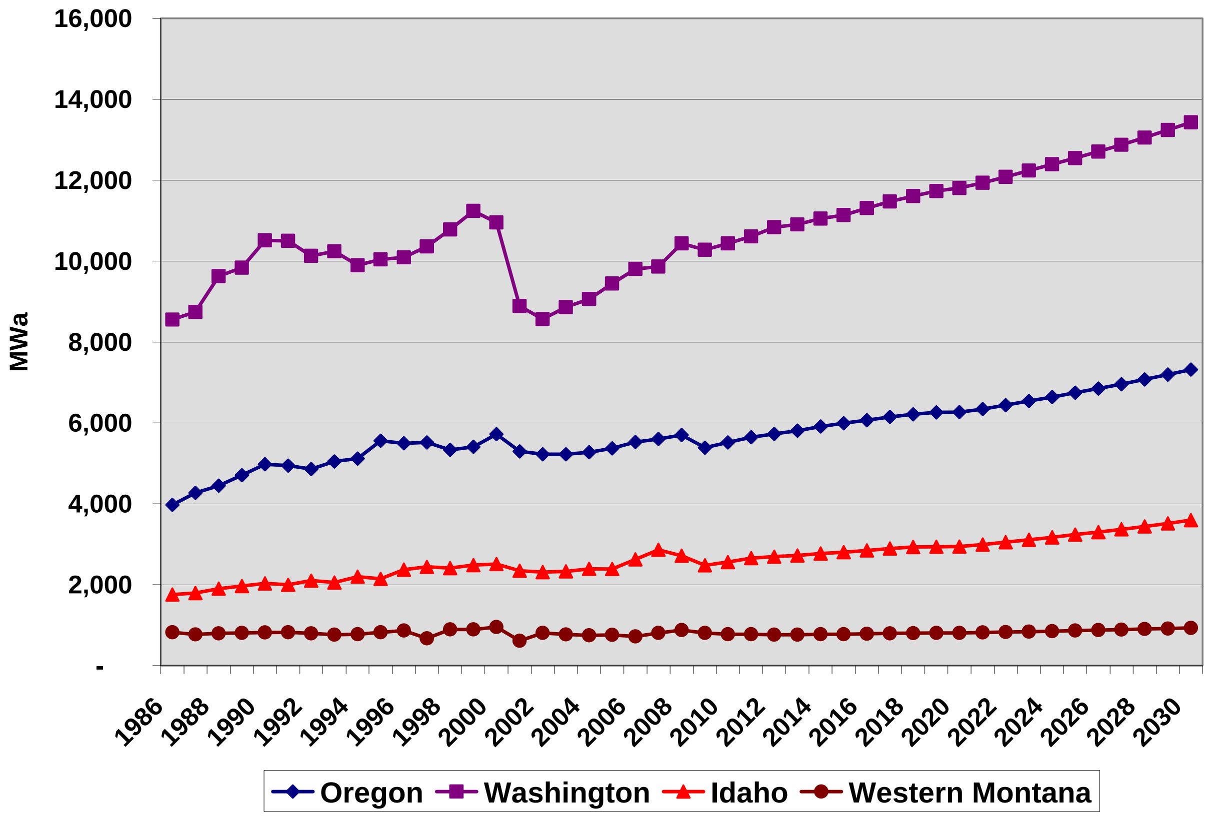


Table C-5: Average Annual Growth Rate[1] in Demand for Electricity

	Oregon	Washington	Idaho	Western Montana	Region
1986-2007	1.64%	0.63%	2.32%	-0.73%	1.07%
2010-2020	1.56%	1.46%	1.46%	1.48%	1.49%
2010-2030	1.24%	1.17%	1.59%	1.28%	1.26%

Monthly Pattern of Demand

Demand is not evenly distributed throughout the year. In the Northwest, demand for electricity is higher in the winter and summer and lower in spring and fall. The historic demand for electricity for the region shows a “W”-shaped profile. Approximately 9-10 percent of annual electricity in the region is consumed in the winter months of January and December. In the

[1] Caution is warranted when interpreting the average annual growth rate. The average annual growth rate is sensitive to medium year values. Additional information on annual demand for each state is available in the companion Excel worksheet available on the Council’s website, and will provide a more accurate picture of historic and future growth.

shoulder months (March through June, and September through November) monthly energy consumption is about 8 percent. In summer months, it is slightly above 8 percent. Similar patterns can be observed in each one of the four states, with electricity demand in Idaho slightly higher in summer and slightly lower than the regional average in winter months.

Figure C-14: Monthly Pattern of Demand for Electricity

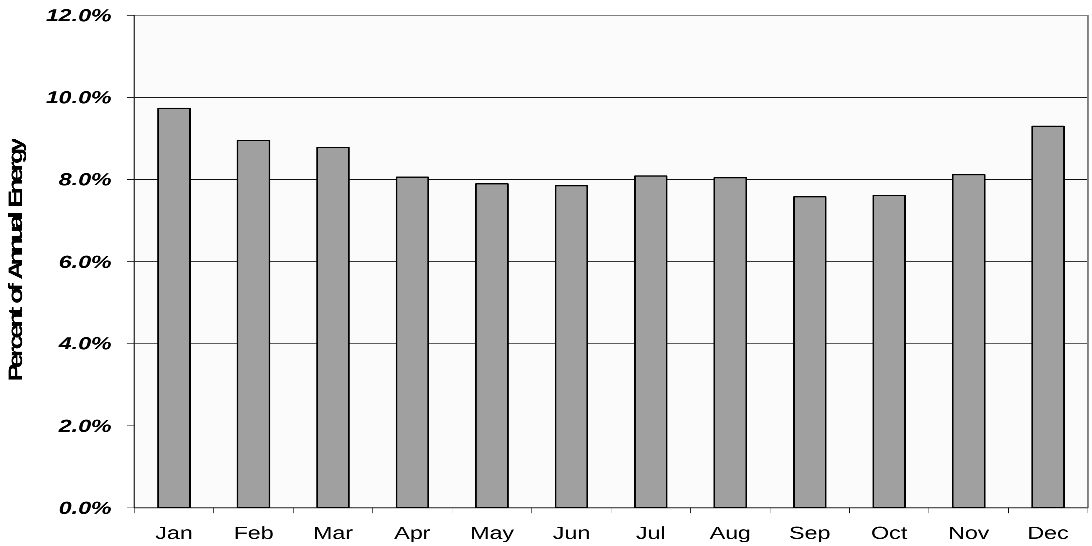


Table C-6: Monthly Pattern of Demand for Electricity

	ID	MT	OR	WA	Region
Dec	9%	9%	9%	9%	9%
January	9%	10%	10%	10%	10%
July	10%	8%	8%	8%	8%
Aug	9%	8%	8%	8%	8%

In order to make sure there are sufficient resources available to meet demand, it is necessary to forecast the timing of peak load.

REGIONAL PEAK LOAD

As discussed in Appendix B of the Sixth Power Plan, the temporal pattern of demand and its peaks are becoming more important. The region was once constrained by average annual energy supplies. Today, the region is more likely to be constrained by sustained-peaking capability.

To better forecast the temporal pattern of demand and hourly load, the Council has developed two sets of models:

- A short-term load forecasting model that projects 3-5 years into the future on an hourly basis. The short-term model is used for the resource adequacy analysis.

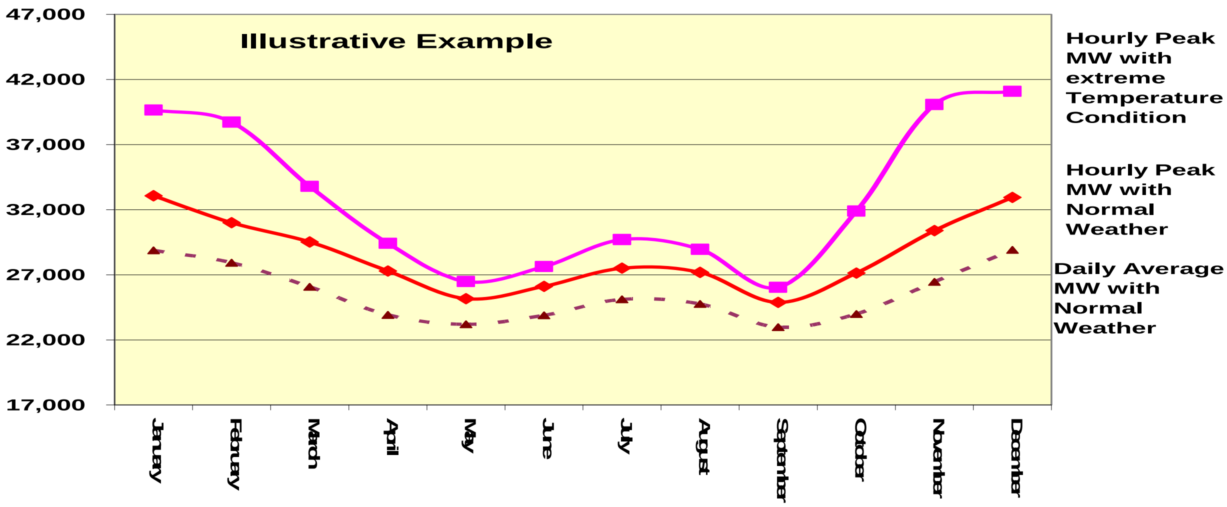
- A long-term load forecasting model that projects 20 years into the future on a monthly basis.

This appendix discusses the long-term forecasting model.

Seasonal Variation in Load

Regional load has significant seasonal variability driven by temperature changes. Although the Northwest is a winter-peaking region, there can be a significant range in winter load. Illustrating this, the following graph measures three examples of load. The dashed line shows the daily average megawatts of energy under normal weather conditions. Winter daily energy demand is about 28,000 megawatts, and summer average demand is about 24,000 megawatts. With normal weather, the peak-hour load in winter reaches over 33,000 megawatts, and the summer peak increases to about 28,000 megawatts. If weather conditions are extreme, then the hourly load can increase substantially and has reached more than 41,000 in winter and more than 30,000 in the summer.

Figure C-15: Range of Variation in Load



Demand versus Load

The demand forecast figures presented earlier were for customer demand and did not include transmission and distribution losses. This energy loss from transmission and distribution varies depending on temperature conditions and the mix of sectors. Higher temperatures mean a greater loss of energy. Transmission and distribution losses also increase as the regional load shifts to the residential or commercial sector. Large industrial customers like the DSIs typically have lower losses because they can receive power at the transmission level. The following table shows the projected annual load and sales for the region.

Table C-7: Annual Demand and Loads (MWa)

	Annual Demand	Annual Load		Annual Demand	Annual Load
2009	18,959	21,369	2020	21,820	24,593
2010	19,292	21,745	2021	22,083	24,890
2011	19,691	22,194	2022	22,399	25,246
2012	20,021	22,566	2023	22,729	25,618
2013	20,205	22,774	2024	23,059	25,990
2014	20,509	23,116	2025	23,400	26,374
2015	20,713	23,346	2026	23,736	26,753
2016	21,005	23,675	2027	24,091	27,153
2017	21,307	24,015	2028	24,472	27,582
2018	21,552	24,292	2029	24,868	28,028
2019	21,736	24,499	2030	25,275	28,488

Resource Adequacy and Peak Forecast

To make sure adequate resources are available to meet load under the range of variations shown in Table C-7, regional resource adequacy guidelines have been established. These guidelines do not focus on peak load for a single hour, but rather use the concept of a sustained-peak period (SPP). The sustained-peak period is defined as an 18-hour period over three consecutive days. The sustained-peak load for adequacy assessment is determined in the short-term forecasting model. A discussion on the development and application of short-term can be found in the Resource Adequacy Forum, February 5, 2007 Technical Committee Meeting.[2]

Peak Load Forecast Methodology (Long-term Model)

One approach to forecasting temporal demand is to use historical monthly and hourly patterns. In the Fourth Power Plan, the Council used an extremely detailed hourly electricity demand forecasting model to estimate future hourly demand patterns. The methodology used in the Sixth Power Plan is similar to the Fourth Power Plan approach, in which the detailed hourly demand for numerous end-uses and sectors built the model's load profile.

In the Sixth Power Plan, monthly demand patterns for specific end-uses were used to create a cumulative regional load forecast. Hourly load profiles for each end-use were mapped against the system load profile and an end-use specific load shape factor (LSF) was calculated. This tells us which end-use is contributing to the peak and by how much. The calculation for LSF is done on a monthly basis. This method allows the Council's model to make specific forecasts for end-uses that are increasing like air conditioning or ICE technologies.

The load shape factors currently used by the Council were gathered from the best available data, but they should be updated. An action item for the Sixth Power Plan is to update the load shape for various end-uses.

[2] http://www.nwcouncil.org/energy/resource/meetings/2007/02/20507%20Tech%20Short%20Term%20Loads.pdf

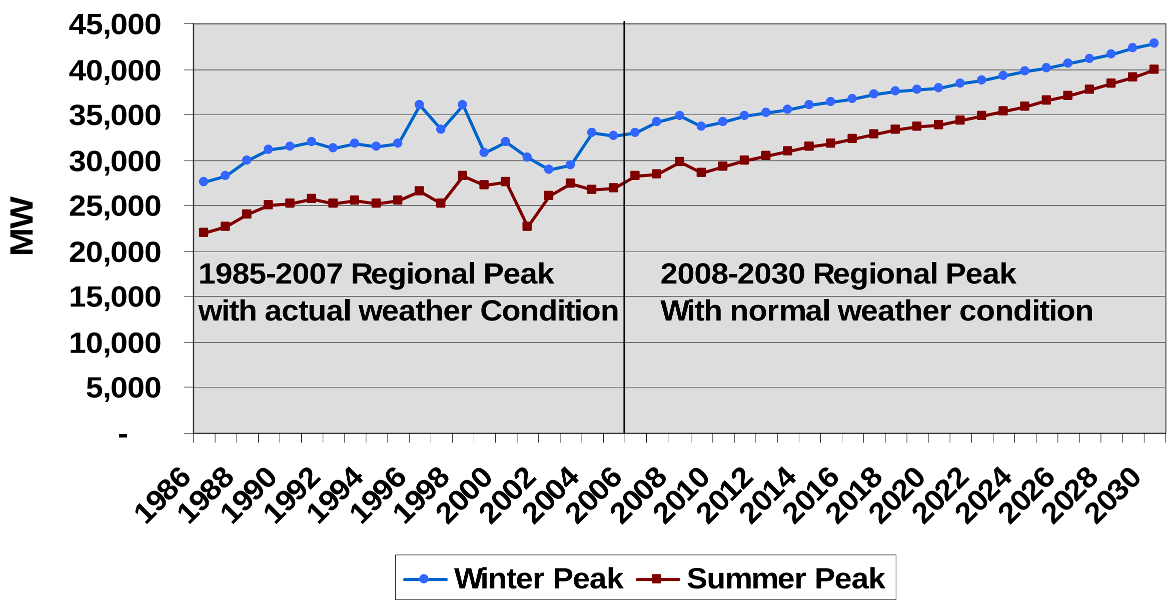
Regional Peak Load Forecasts

The regional peak load is expected to grow from about 34,000 megawatts in 2010 to around 43,000 megawatts by 2030 at an average annual growth rate of 1.1 percent. With no climate change scenarios, the region is expected to remain winter peaking until near the end of the planning horizon. Figure C-16 shows the forecast peak load for winter and summer months under different scenarios. Note that the estimated peak load for 2007 reflects the actual peak temperatures for 2007. However, the peak load forecasts for 2010, 2020, and 2030 are based on normal weather conditions. The forecast of peak load suggests that the region's winter and summer peak loads become close by the end of forecast period, about 3,000 MW apart. The growth rate for the summer peak is higher than the winter peak. The growth rate for the winter peak is 1.1 percent per year compared to the summer peak growth rate of 1.6 percent.

Table C-8: Total Summer and Winter Peak Load Forecasts MW

	2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2010-2030
Medium - Winter	33,908	34,184	37,977	42,814	1.06%	1.13%
Medium - Summer	28,084	29,211	33,800	39,865	1.47%	1.57%

Figure C-16: Peak Load Demand for Electricity (MW)



The growth rate of summer and winter peak load depends on the growth rate of the economy in general. In the high-growth scenario, the summer peak grows at 1.9 percent per year. In the low-growth scenario, the summer peak grows at 1.1 percent per year. The winter peak load in the region could increase from about 34,000 megawatts in 2007 to about 46,000 megawatts in 2030. The summer peak load is forecast to grow at a faster rate, 1.1-1.9 percent per year, increasing from about 28,000 megawatts in 2007 to about 43,000 megawatts by 2030.

Table C-9: Total Summer and Winter Peak Load Forecasts MW

	2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2010-2030
Low - Winter	33,908	33,572	35,412	36,949	0.5%	0.5%
Low - Summer	28,084	28,517	32,027	35,559	1.2%	1.1%
Medium - Winter	33,908	34,184	37,977	42,814	1.1%	1.1%
Medium - Summer	28,084	29,211	33,800	39,865	1.5%	1.6%
High - Winter	33,908	34,611	39,397	46,788	1.3%	1.5%
High - Summer	28,084	29,706	34,923	43,360	1.6%	1.9%

Residential Sector

Peak load for the residential sector during the winter season is estimated to increase from about 19,700 megawatts in 2007 to about 24,000 megawatts by 2030, an annual growth rate of about 0.8 percent per year. This growth rate is slower than forecast growth rate for energy demand in the residential sector. During the summer peak, high demand by the residential sector is anticipated to increase by 1.6-2.9 percent per year, depending on the economic growth scenario.

Table C-10: Residential Summer and Winter Peak Load Forecasts MW

Residential	2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2010-2030
Low - January	19,701	19,373	19,175	19,505	-0.1%	0.2%
Low - July	8,101	8,422	9,173	10,791	0.9%	1.6%
Price-effect - January	19,701	19,538	21,070	23,687	0.8%	1.2%
Price-effect - July	8,101	8,477	9,865	12,513	1.5%	2.4%
High - January	19,701	19,637	22,090	26,184	1.2%	1.7%
High - July	8,101	8,510	10,257	13,612	1.9%	2.9%

Commercial Sector

Peak load for the commercial sector during the winter season is estimated to increase from about 6,200 megawatts in 2007 to about 9300 megawatts by 2030, an annual growth rate of 1.8 percent per year. The summer season peak loads in this sector are projected to grow from 10,250 megawatts in 2007 to about 16,000 megawatts in 2030, or about 2.0 percent per year. This growth rate is higher than the growth rate in the annual energy use forecast for this sector.

Table C-11: Commercial Summer and Winter Peak Load Forecasts MW

Commercial	2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2010-2030
Low - January	6,230	6,630	7,831	8,444	1.7%	0.8%
Low - July	10,250	10,971	13,351	14,756	2.0%	1.0%
Price-Effect- January	6,230	6,809	8,298	9,274	2.0%	1.1%
Price-Effect- July	10,250	11,264	13,940	15,678	2.2%	1.2%
High - January	6,230	6,987	8,572	9,982	2.1%	1.5%
High - July	10,250	11,554	14,182	16,399	2.1%	1.5%

Industrial Sector

The load profile of the industrial sector is typically flat, with little hourly or seasonal variation. In the winter, the estimated industrial sector contribution to the electricity system's peak is anticipated to be about 5,760 megawatts in 2007, increasing to about 6,300 megawatts by 2030. During the summer season, the industry's contribution to the region's peak use is slightly greater than its contribution to winter peak demand because the regional summer peak usually occurs during mid-day working hours, whereas the system winter peak occurs during either early morning or early evening.

Table C-12: Industrial Summer and Winter Peak Load Forecasts MW

Industrial (net of irrigation)	2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2010-2030
Low - January	5,760	5,120	5,093	5,128	-0.1%	0.1%
Low - July	6,177	5,601	5,629	5,655	0.1%	0.0%
Price-Effect- January	5,760	5,380	5,481	6,301	0.2%	1.4%
Price-Effect- July	6,177	5,867	6,036	6,892	0.3%	1.3%
High - January	5,760	5,120	5,093	5,128	-0.1%	0.1%
High - July	6,177	5,537	5,381	4,941	-0.3%	-0.8%

Irrigation Sector

Agricultural crops are not irrigated in the winter, so the irrigation sector does not contribute to the winter system peak. However, this sector can contribute significantly to the system peak in the summer. The estimated contribution of the irrigation sector to the 2007 summer peak was about 2,900 megawatts. Peak-load demand is projected to grow to about 3,000 megawatts by 2030.

Table C-13: Irrigation Summer and Winter Peak Load Forecasts MW

Irrigation	2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2010-2030
Low - January	0	0	0	0	0.0%	0.0%
Low - July	2,879	2,010	2,252	2,633	1.1%	1.6%
Price-Effect- January	0	0	0	0	0.0%	0.0%
Price-Effect- July	2,879	2,043	2,375	2,971	1.5%	2.3%
High - January	0	0	0	0	0.0%	0.0%
High - July	2,879	2,074	2,501	3,347	1.9%	3.0%

Street Lighting and Public Facilities

This sector consists of street lighting, traffic lights, and water and sewer facilities. The energy forecast for this sector is typically combined with the commercial sector demand. In 2007, this sector contributed an estimated 838 megawatts to the summer peak and by 2030, this sector's share of summer peak is projected to grow to about 1,100 megawatts. This sector is projected to grow at about 1.0 percent per year between 2010 and 2030.

Table C-14: Irrigation Summer and Winter Peak Load Forecasts MW

Public Facilities & Street Lighting	2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2010-2030
Low - January	741	774	869	958	1.2%	0.99%
Low - July	838	874	979	1,079	1.1%	0.97%
Price-Effect- January	741	774	869	958	1.2%	0.99%
Price-Effect- July	838	874	979	1,079	1.1%	0.97%
High - January	741	774	869	958	1.2%	0.99%
High - July	838	874	979	1,079	1.1%	0.97%

Calculations for Alternative Load Forecast Concepts

In Chapter 3 of the Sixth Power Plan, under the heading "Alternative Load Forecast Concepts", the three different but related load forecasts are produced for use in the Council's resource planning process are discussed. In this section, we will discuss how the conservation targets were netted out of the price-effect forecast to produce the "sales"[3] forecast load. A "sales" forecast, represents the actual expected sales of electricity after all cost-effective conservation has been achieved. It incorporates the effects of electricity prices and the cost-effective conservation resources that are selected by the Resource Portfolio Model. The sales forecast captures both price-effects and take-back effects (due to increased usage as efficiency of usage increase).

To calculate the Sales forecast, we start with taking the conservation resource bundles (lost-opportunity and discretionary), and unbundle them into their sector and end-use specific constituents for each year. The sector and end-use specific estimates of the annual conservation targets were then netted out of the frozen-efficiency load forecast to estimate the "sales" forecast. Whenever possible, the conservation target for a given sector and end-use was netted out of the appropriate sector and end-use. However, conservation targets are estimated at a greater level of resolution than the long-term modeling tool's end-uses. So, in some cases multiple conservation targets were netted out of same end-use and sector. For example, the conservation targets for commercial lighting consist of savings due to improved lighting power density as well as better controls for interior and exterior lighting. In modeling the impact of these conservation measures, we could only modify the lighting in the commercial sector without distinguishing the nature of the lighting measure, whether it was controls or reduced power density. To properly reflect the impact of conservation measures on the energy and peak loads, a more detailed treatment of conservation savings would have been needed. In this analysis we have made a simplifying and conservative assumption that conservation measure load shapes are identical to the end-use load shapes.

The following table shows the cumulative conservation target for 2029, as well as the mapping between conservation measures and end-use in the long-term model that was modified to incorporate impact of conservation savings on load.

[3] "Sales" forecast as well as price-effect and frozen efficiency can be measured at consumer site or at generator site (which will include T&D losses). When the reference is to "demand" it is measured at customer site, and when the reference is to "load" it is measured at generator site.

Table C-15: Modeling Impact of Conservation Targets

Sector	Conservation Measures	Calendar year 2029 MWa (at generator site)	Long-term Demand Forecast Model End-use
Residential	Heat Pump Water Heater	492	Water Heating
	Television and Set Top Box	469	Entertainment Center
	Computers and Monitors	358	Entertainment Center
	Heat Pump Conversions	418	Water Heating
	Clothes Washer	108	Clothes Washer
	Dishwasher	16	Dishwasher
	Refrigerator	41	Refrigeration
	Freezer	15	Freezer
	New Construction Shell	170	Space Heating and Cooling
	Heat Pump Upgrades	97	Space Heating and Cooling
	Weatherization	284	Space Heating and Cooling
	Ductless Heat Pump	210	Space Heating and Cooling
	Lighting	249	Lighting
	Showerheads	35	Water Heating
	Total	**3148**	
Commercial	Lighting Power Density (lost Op)	340	Lighting
	Lighting Power Density (discretionary)	30	Lighting
	Interior Lighting Controls (lost Op)	90	Lighting
	Exterior Lighting (lost Op)	190	Lighting
	Integrated Building Design	60	Space Conditioning
	Packaged Refrigeration Equipment	50	Refrigeration
	Controls Commission Complex HVAC	110	Space Conditioning
	Controls Optimization Simple HVAC	30	Space Conditioning
	Grocery Refrigeration Bundle	90	Refrigeration
	Computer Servers and IT	130	Misc. Plug-in electric
	Network PC Power Management	70	Misc. Plug-in electric
	Other Commercial Measures	20	Misc. Plug-in electric
	Total	**1370**	
Industrial	All industrial Measures	760	Spread over all endues and industries
Irrigation	All Irrigation Measures	100	Motors
Public Facilities	Municipal Sewage Treatment & Water Supply	50	Motors
All Sectors	Distribution Efficiency Measures	400	Spread over all sectors And end-uses

ELECTRICITY DEMAND GROWTH IN THE WEST

Electricity demand is analyzed not only by sector but by geographic region. The Council's AURORAxmp electricity market model requires energy and peak load forecasts for 16 areas. Four of these areas make up the Pacific Northwest -- forecasts for these areas come from the Council's demand forecast model. Forecasts for the remaining 12 areas come from the Transmission Expansion Planning Policy Committee (TEPPC), which is part of the Western Electricity Coordinating Council (WECC).

For the two California areas, Council staff used forecasts submitted by the California Energy Commission from 2008-2020. For the remaining 10 areas (not in California and not in the Pacific Northwest) Council staff used forecasts from TEPPC for 2012-2018. For the period 2008-2011 these 10 areas' demand for electricity was interpolated between historic levels in 2008 and forecast levels in 2012, with a 4 percent reduction in 2009 and 2010 to reflect the current recession. AURORA requires area load projections for each year to 2053, so Council staff extended the forecasts past 2020 (for California) and 2018 (for the other 10 areas) by calculating a rolling average for the past five years.

Table C-16: Naming Convention for Aurora Areas

Area Name	Short Area Name
Pacific NW Eastside	PNWE
California North	CAN
California South	CAS
British Columbia	BC
Idaho South	IDS
Montana East	MTE
Wyoming	WY
Colorado	CO
New Mexico	NM
Arizona	AZ
Utah	UT
Nevada North	NVN
Alberta	AB
Mexico Baja CA North	BajaN
Nevada South	NVS
Pacific NW Westside	PNWW

AURORA's model information covers a large and diverse area. Figure C-17 shows the 2010 projected demand for energy.

Figure C-17: 2010 Projected Electricity Load by AURORA Area (MWa)

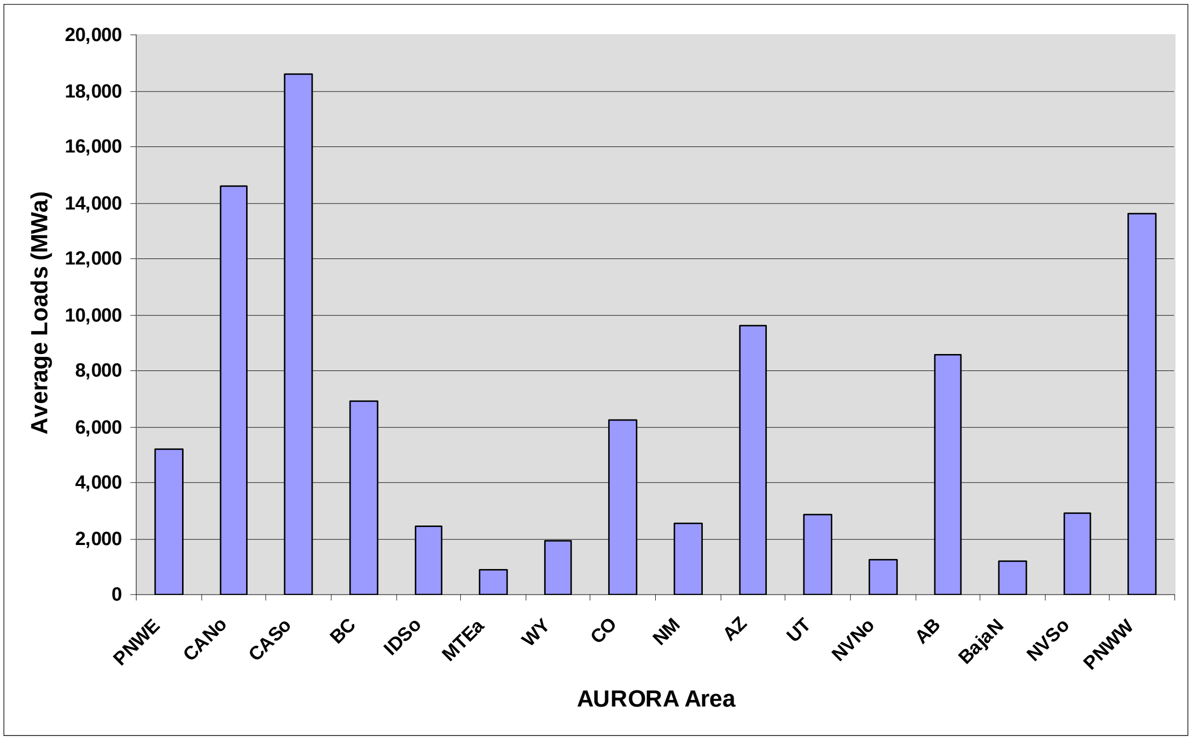


Figure C-18 shows the 2010-2030 projected growth rates for demand in the 16 geographic areas. The figure shows the projected growth rates for areas that are expected to experience demand increases of less than 1 percent and areas that are forecast to experience demand increases of nearly 4 percent. The highest projected rates of change are the geographic areas of Alberta, Canada, and Arizona, followed by Wyoming, Utah and southern Nevada. The lowest rates are for PNW Eastside, British Columbia, Eastern Montana and PNW Westside, all anticipated to grow at less than 0.5 percent by 2027. The four Pacific Northwest areas have projected load growth rates at the lower end of the range of the WECC area, at about 0.4 percent by 2030.[4] These areas include: the eastern portions of Oregon and Washington, the northern part of Idaho (PNWE), southern Idaho (IDS), eastern Montana (MTEa), and the western portions of Oregon and Washington (PNWW).

[4] All forecasts are net of planned conservation, which reduces the forecasts quite substantially in the Pacific Northwest and several other areas.

Figure C-18: Percent Annual Growth 2010-2030 by AURORA Area (MWa)

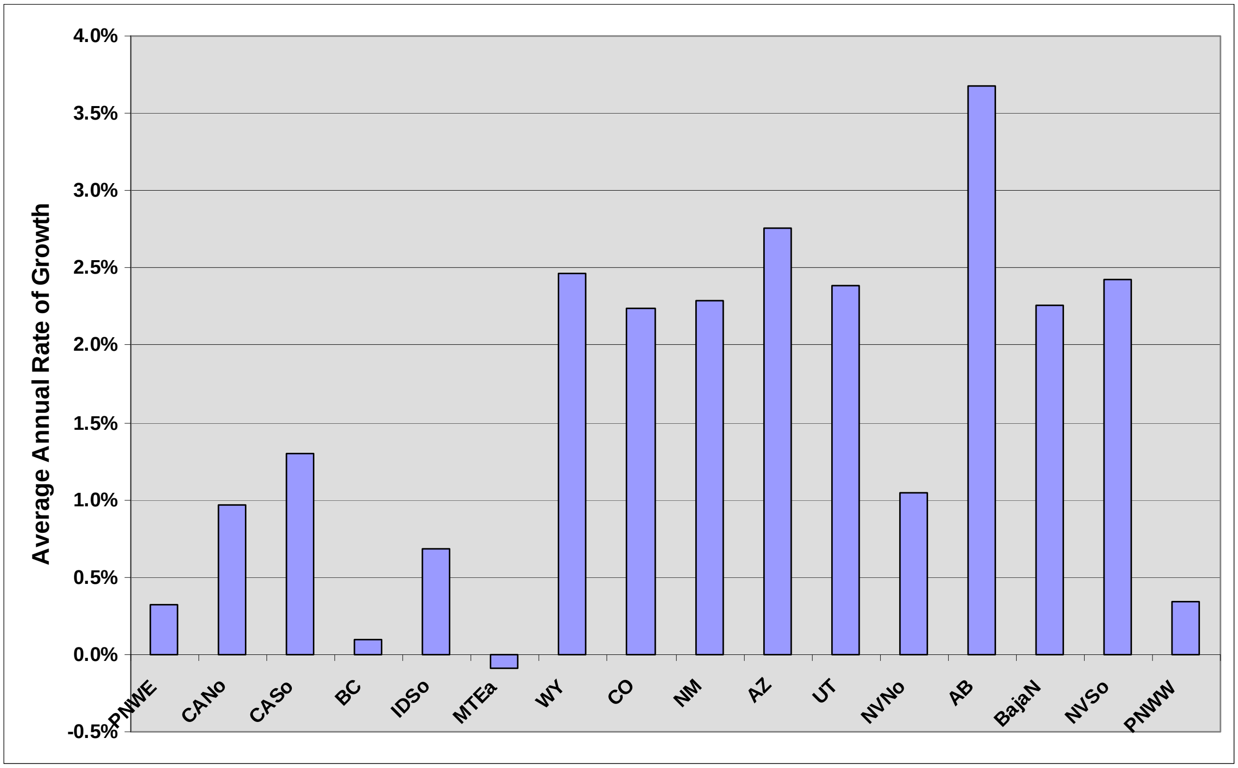


Figure C-19: 2010 Projected Peak Load by AURORA Area (MW)

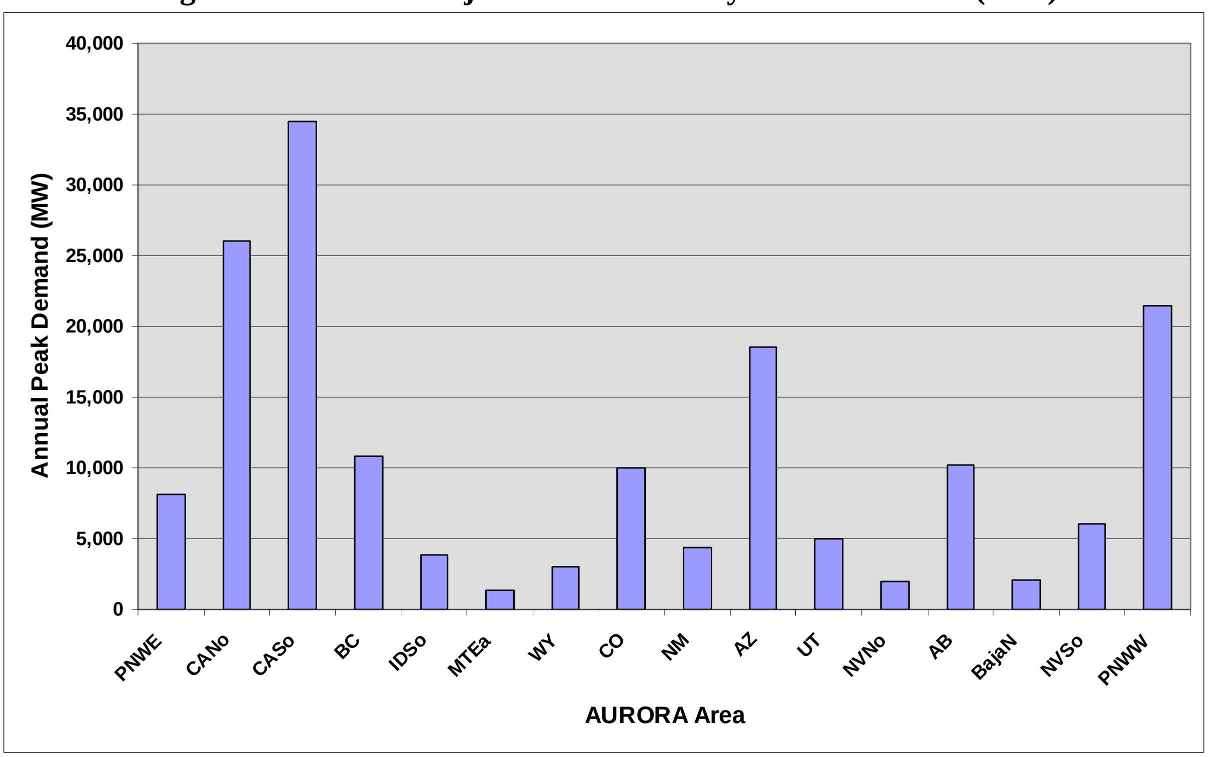


Figure C-19 shows the 2010 projected peak load by AURORA area. The figure demonstrates a wide range in projections of peak demand among geographic areas. It is important to note that these projections are non-coincident (individual utility) peaks, and while six of the areas (PNWE, BC, MTEa, WY, AB, and PNWW, totaling about 55,000 megawatts) are winter peaking, the rest of WECC, totaling about 102,000 megawatts, are summer-peaking areas. The WECC area as a whole is summer peaking.

SPECIAL TOPICS

This section describes the impact of custom data centers and plug-in hybrid electric vehicles (PHEV) on demand. The effect of PHEV on demand is treated as a sensitivity analysis in Chapter 3.

Estimating Electricity Demand in Data Centers

Background on Trends in Data Center Load

A brand new load type has emerged recently, starting in 2000. Large data centers have been attracted to the Northwest because of its low electricity prices and moderate climate, meaning fewer storms and power interruptions.

What is a Data Center?

"Data center" is a generic term used to describe a number of different types of facilities that house digital electronic equipment for Internet-site hosting, electronic storage and transfer, credit card and financial transaction processing, telecommunications, and other activities that support the growing electronic information-based economy.[5] In general, data centers can be categorized into these two main categories:

- Custom data centers, such as Google, Yahoo, and Microsoft sites in the Grant County PUD and Northern Wasco County PUD. These data centers are typically very large, consisting of thousands of servers and representing a significant demand for power. They are usually sited close to transmission facilities and are typically charged industrial retail rates by their local utility.

- Hidden data centers, like those in business offices, may include a small separate office or closet with a few servers, or larger server facilities with hundreds of servers. These data centers are called “hidden data centers” because they are part of existing commercial businesses. They are usually in urban settings and are typically charged commercial retail electric rates by their local utility.

Tracking load from data centers (especially custom data centers) is important because their growth rate has been swift, and their size generally creates a large demand. The Council currently estimates that the region has about 300 average megawatts of connected load used by custom data centers, and another 300 average megawatts of load that can be attributed to hidden

[5] http://www.gulfcoastchp.org/Markets/Commercial/DataCenters

data centers. If national projected trends for non-custom servers holds true, the load from these data centers can increase by 50 percent by the year 2011.

National Picture: Research conducted nationally for the EPA[6] in 2005 shows that electricity sales for servers and data centers was about 6,200 average megawatts or about 1.5 percent of total U.S. retail electricity sales. This estimated level of electricity consumption is more than the electricity consumed by the nation's color televisions, and is similar to the amount of electricity consumed by approximately 5.8 million average U.S. households (or about 5 percent of the total U.S. housing stock). The energy use of the nation's servers and data centers in 2006 is estimated to be more than double the electricity consumed for this purpose in 2000. The power and cooling infrastructure that supports IT equipment in data centers also uses significant energy, and accounts for 50 percent of the total electricity consumption of these centers. Among the different types of data centers, the nation's largest (enterprise-class facilities used by the banking industry or the airline industry) and most rapidly growing data centers use more than one-third (38 percent) of the electricity from this sector.

This total does not yet include the load of larger custom server sites. No detailed estimates for load from these types of data centers exist. However, Lawrence Berkeley Labs conservatively estimates the demand of these sites to be about 900 average megawatts nationally. In total, 1.7 percent of national retail electric sales can be attributed to servers and data centers.

Regional Picture: To estimate the total load for servers and data centers in the region, the Council assumed that the region's demand from these sites is similar to the nation's demand. To verify this assumption, the percent of each state's gross state product generated by information-intensive industries (such as Internet-service providers and financial institutions) was calculated. Then, the same percentage at the national level was calculated and the two figures compared. The analysis showed that the information-intensive industries' contribution to the GSP is similar to the contribution of the same industries nationally. The region as a whole is similar to the nation in the contribution of information-intensive industries to the regional economy. The analysis showed that in the Northwest, 1.47 percent of total electricity sales, or about 285 average megawatts, can be attributed to servers and data centers.

This estimate excludes custom data centers attracted to the region by access to fiber optic networks, low electricity prices, and a moderate climate. The Council contacted utilities serving these customers for more information. Preliminary estimates put the custom data centers' consumption at about 300 average megawatts of connected load. Typically, custom data centers project their future peak power requirements and the local utility then sizes the distribution facilities to those requirements. Conversations with utilities indicate that the full load would occur over several years rather than immediately.

Future Trends: Nationally, electricity sales to server operations have grown suddenly and rapidly. By 2010, the number of total U.S. installed servers is expected to increase from 5.6 million in 2000 to over 15 million servers. This phenomenal sales growth highlights the impact of servers and data centers on demand. But there are also many opportunities to reduce this sector's demand. In the EPA study mentioned earlier, three different energy-efficiency scenarios were explored:

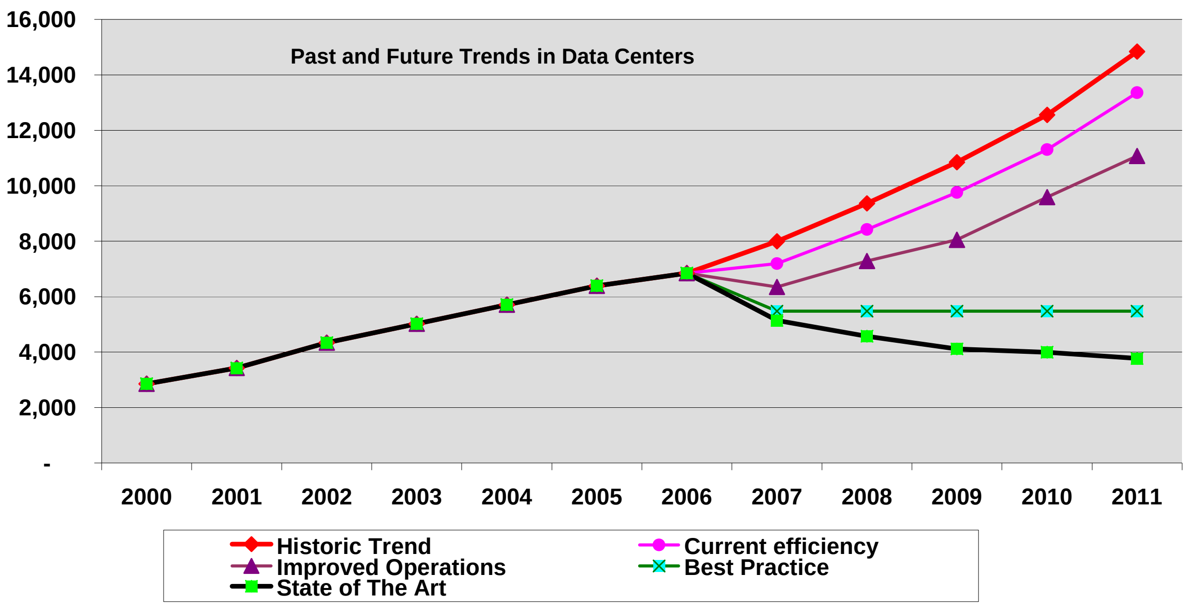
[6] Report to Congress on Server and Data Center Energy Efficiency Public Law 109-431

- The "**improved operation**" scenario includes energy-efficiency improvements beyond current efficiency trends that are essentially operational changes and require little or no capital investment. This scenario represents the "low-hanging fruit" that can be harvested simply by operating the existing capital stock more efficiently. An example of low-hanging fruit is isolating hot and cold isles in the data center, thus reducing air-conditioning demand. Potential savings from this category of improved energy efficiency: 30 percent.

- The "**best practice**" scenario represents the efficiency gains that can be obtained through the more widespread adoption of practices and technologies used in the most energy-efficient facilities in operation today. Potential savings from this category of improved energy efficiency: 70 percent.

- The "**state-of-the-art**" scenario identifies the maximum energy-efficiency savings that could be achieved using available technologies. This scenario assumes that U.S. servers and data centers will be operated at the maximum possible energy efficiency using only the most efficient technologies and the best management practices available. Potential savings from this category of improved energy efficiency: 80 percent.

Figure C-20: National Forecast for Demand from Data Centers



If regional trends follow national trends, load from non-custom servers will increase from its current 285 average megawatts to about 570 average megawatts. Load for custom data centers may also double by 2010. However, there are indications that this projected doubling may not occur. Growth-limiting factors include technological improvements like the use of "virtualization" (using one server to do the job of many), the use of alternative storage technologies, better power management, as well as other limiting factors such as access to water for cooling needs, limitations on tax incentives, and limitations on below-market electricity rates.

Conservation Opportunities: Significant conservation opportunities may be available, depending on the type of data center. For example, installing the proper size of cooling equipment can significantly reduce consumption. Cooling technologies for server equipment may help the industry maintain, rather than increase, the cost of custom data centers. Currently, we do not have a good baseline assessment of the installed cooling equipment in hidden and custom data centers. An action item for the Sixth Power Plan is to establish such a baseline.

Methodology for Estimating Custom Data Center Loads

Load for non-custom (hidden) data centers is imbedded in the commercial sector load forecast and is not separately estimated. Load for custom data centers is forecast separately using the following method:

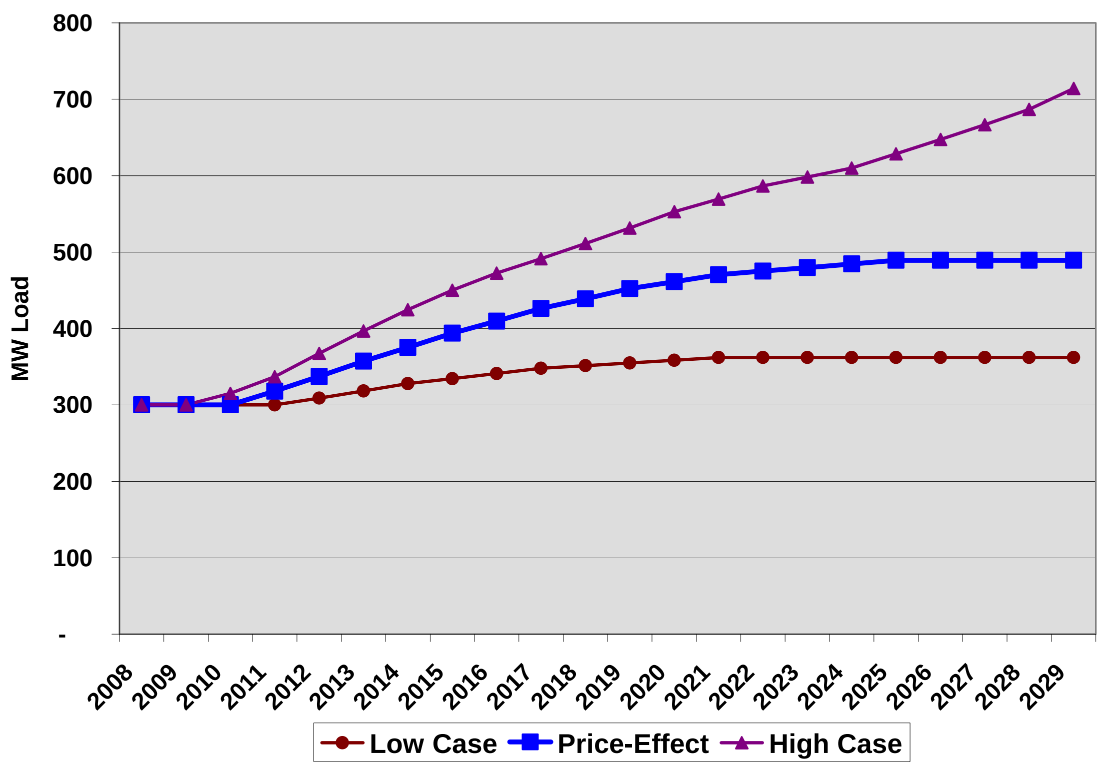
Load for this type of data center in 2008 was estimated. Two trends were then considered. The first trend reflects the increase of demand for services from this sector at a rate of 3 -10 percent per year (3 percent for a low-growth scenario, 7 percent for a medium-growth scenario, and 10 percent for a high-growth scenario). The second trend is the potential improvement in energy efficiency in data centers. Three alternative scenarios for potential improvement in energy efficiency were considered. The medium growth scenario assumed that improvements in energy efficiency start at about 1 percent per year in 2012, increasing gradually to 7 percent per year by 2026. The low-growth scenario assumed that energy-efficiency improvements would be on a slower trajectory, starting at about 1 percent in 2015, and ramping up to about 3 percent by 2022. The high-growth scenario assumed a more rapid growth path for energy-efficiency improvements, starting at 1 percent per year in 2012, increasing to 7 percent by 2020, and 10 percent by 2026. The combination of load growth factors and improvement in energy efficiency result in a flat load growth for the data centers in the later parts of the forecast period. The assumed improvements in energy efficiency presented here are market-driven and are not considered as part of the Council’s conservation potential.

The year-by-year growth in demand and improvement in efficiency for the medium case scenario is shown in the following table. The following graph shows the projected load for alternative energy efficiency and load-growth scenarios. It is assumed that the current estimated connected load of 300 average megawatts would be sufficient to meet the load from custom data centers until 2012.

Table C-17: Medium Case Trends in Data Center Loads

	Growth in Demand	Increase in Efficiency	Load MWa
2008-2011	0%	0%	300
2012	7%	-1%	318
2013	7%	-1%	337
2014	7%	-2%	354
2015	7%	-2%	372
2016	7%	-3%	386
2017	7%	-3%	402
2018	7%	-4%	414
2019	7%	-4%	426
2020	7%	-5%	435
2021	7%	-5%	444
2022	7%	-6%	448
2023	7%	-6%	453
2024	7%	-6%	457
2025-2030	7%	-6%	462

Figure C-21: Projected Load (MW) from Custom Data Centers



Possible Future Trends for Plug-in Hybrid Electric Vehicles

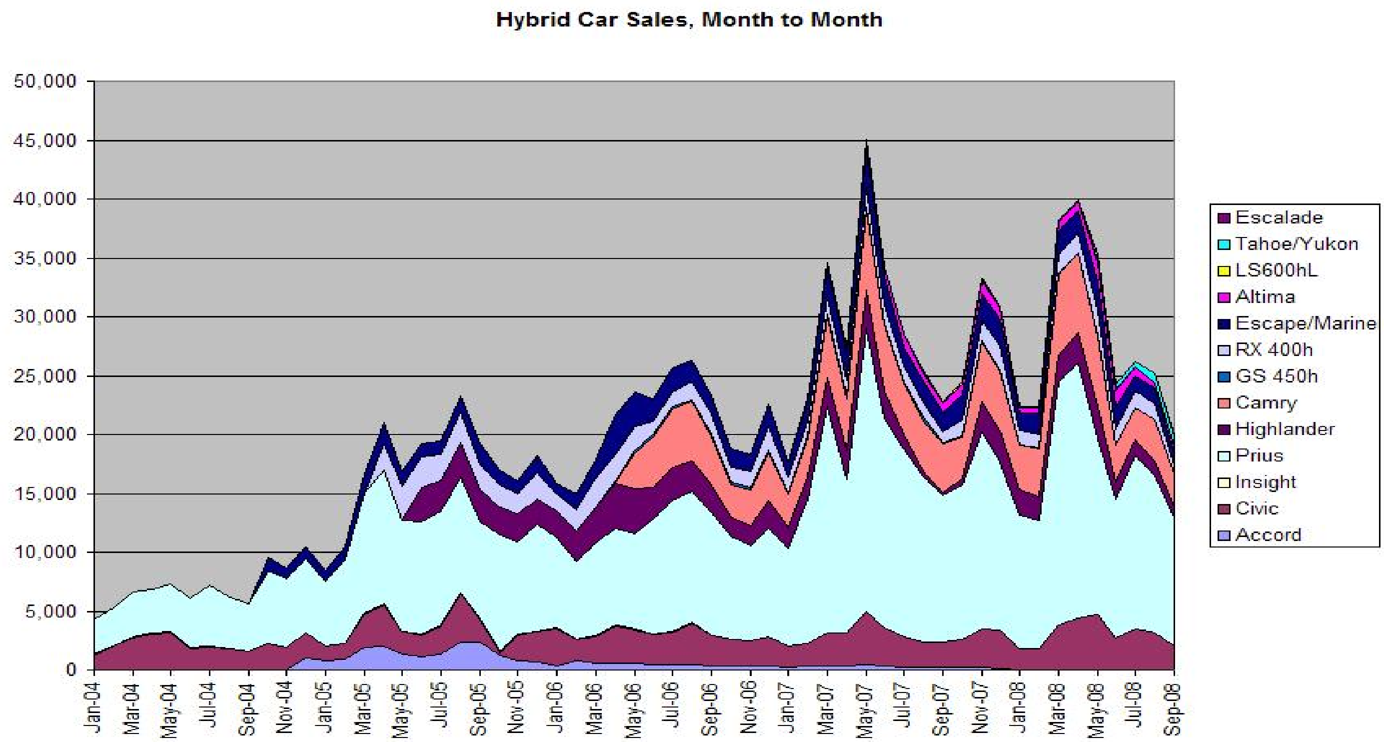
The following is a "What If" analysis concerned with the impact of plug-in electric hybrid vehicles on electrical load in the Northwest over the next 20 years. The Council's analysis is limited to plug-in hybrid vehicle with an electric motor, a plug to recharge the battery and an internal combustion engine.

Background

Concern for the environment and volatile gasoline prices have created unprecedented interest in alternative fuel and hybrid vehicles. Hybrid vehicles have been available in the U.S. market since 2000 in limited quantities. The hybrid vehicles offered today are powered by internal-combustion engines, with batteries that recharge during driving, and an electric motor to assist with power demand. Hybrids do not need to be plugged in, yet they deliver exceptional mileage compared to their gas-only counterparts. Hybrids are considered environmentally friendly alternatives to traditional internal-combustion vehicles.

Hybrid vehicle sales did not increase substantially until after 2004. According to R. L. Polk and Co., nationwide sales of new hybrid vehicles increased from about 84,000 in 2004 to about 200,000 in 2005; to 250,000 in 2006; and to about 350,000 in 2007. However, in 2008, hybrid vehicle sales were plagued by the same problems as conventional vehicles sales. In 2008, new hybrid vehicle sales declined for the first time due to the housing crisis, credit crunch, and declining fuel prices. Cumulative sales for January through September 2008 were 2 percent lower than the comparable period in 2007.

Figure C-22: Nationwide Sales of Hybrids 2004-Sep 2008



Source: R. L. Polk and Co. Hybrid Car Sales, September 2008

Hybrid vehicles usually cost more than comparable conventional vehicles, but they produce significantly lower CO2 emissions. To reduce the lifetime cost of these vehicles, state, federal, and local governments have offered incentives in the form of direct reduced fees (such as registration fees) and tax credits. In the Northwest, Oregon and Washington offer tax incentives for PHEV purchases. Government agencies in Washington, Oregon, and Idaho are required to reduce the petroleum consumption of their fleets by increasing the fuel economy of the vehicles they purchase, and by reducing the number of miles driven by each employee. In the state of

Washington, beginning January 1, 2009, new passenger cars, light-duty trucks, and medium-duty passenger vehicles that are dedicated alternative fuel vehicles (AFVs) are exempt from the state sales and use taxes. Washington agencies must take all reasonable actions to achieve a 20 percent reduction in petroleum use in all state and privately owned vehicles used for state business by September 1, 2009. In Oregon, the Department of Energy offers two income tax credits for alternative and hybrid vehicles for both residents and business owners. Oregon residents are eligible for a residential energy tax credit of up to $1,500 toward the purchase of qualified AFVs.

Potential Effects on Electricity Demand

Factory-made plug-in hybrid electric vehicles are not currently available to the public. Consumer demand for hybrid vehicles can give us a window into the potential demand for plug-in electric vehicles. More information about marketplace acceptance of these vehicles is needed to be able to forecast their effect on the region's demand. A "what if" analysis was conducted to estimate their potential effect on electricity demand.

According to R. L. Polk and Co., there is a strong relationship between the customer's previously owned vehicle and the size and type of a newly purchased hybrid vehicle, including plug-in hybrids. To analyze the effect of plug-in electric vehicles on electricity demand, the Council used Global Insight's October 2008 forecast scenarios for the total number of new light vehicles. The following table projected new light vehicle sales in the four Northwest states. Three growth rates in new light vehicles and three for penetration rates were considered.

Table C-18: Projected New Light Vehicles (000)

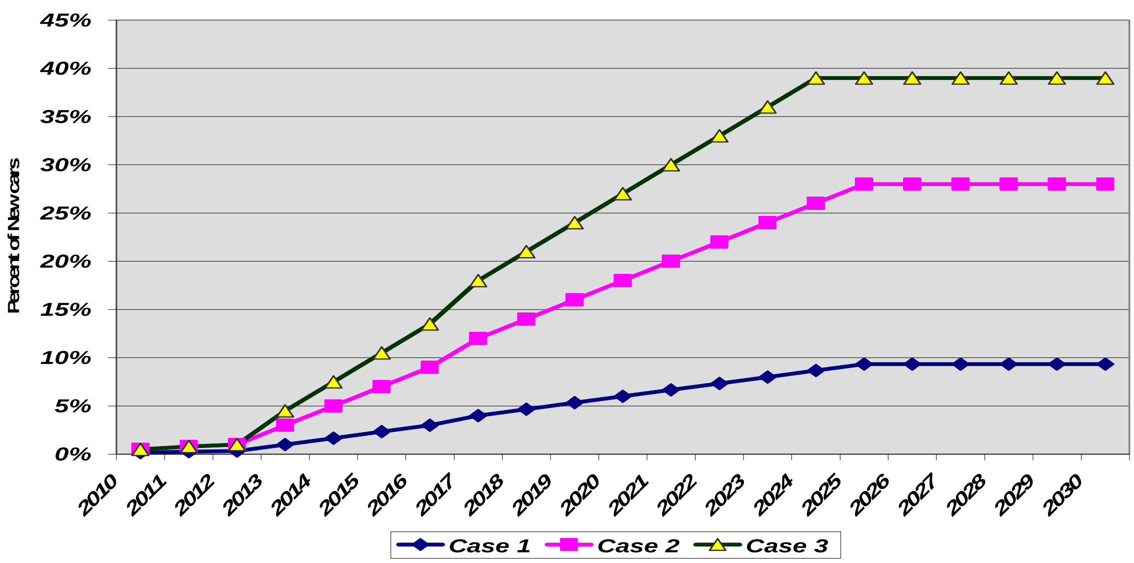
	Case 1	Case 2	Case 3
2010	481	606	560
2011	513	620	591
2012	537	627	616
2013	543	632	629
2014	548	636	641
2015	561	639	659
2016	564	640	673
2017	565	643	90
2018	571	649	706
2019	568	658	718
2020	560	665	730
2021	553	669	749
2022	549	675	755
2023	545	681	762
2024	543	688	774
2025	543	696	791
2026	543	704	806
2027	543	710	819
2028	542	717	837
2029	543	724	856
2030	543	732	878

The penetration rate for plug-in electric vehicles will be limited. The case 1 scenario assumes a 0.5 percent penetration rate for 2010. By 2025, it is assumed that 28 percent of new light vehicles could be plug-in hybrids. In the high-penetration scenario, case 3, it is assumed that 39 percent of new vehicles will be plug-in electric by 2025. In the low-penetration scenario, case 1, plug-in electric vehicles are assumed to represent 9 percent of the new car market by 2025.

Table C-19: Penetration Rate and Cumulative Number of PHEV in the Region (000)

	Case 1	Case 2	Case 3	Case 1	Case 2	Case 3
2010	0.2%	0.5%	0.5%	1	3	3
2011	0.3%	0.8%	0.8%	2	7	8
2012	0.3%	1.0%	1.0%	4	13	14
2013	1.0%	3.0%	4.5%	9	31	42
2014	1.7%	5.0%	7.5%	19	61	90
2015	2.3%	7.0%	10.5%	32	104	157
2016	3.0%	9.0%	13.5%	49	159	244
2017	4.0%	12.0%	18.0%	71	235	359
2018	4.7%	14.0%	21.0%	98	324	496
2019	5.3%	16.0%	24.0%	128	426	654
2020	6.0%	18.0%	27.0%	162	541	833
2021	6.7%	20.0%	30.0%	199	669	1034
2022	7.3%	22.0%	33.0%	239	811	1257
2023	8.0%	24.0%	36.0%	282	966	1502
2024	8.7%	26.0%	39.0%	329	1135	1770
2025	9.3%	28.0%	39.0%	380	1320	2042
2026	9.3%	28.0%	39.0%	431	1506	2316
2027	9.3%	28.0%	39.0%	481	1694	2593
2028	9.3%	28.0%	39.0%	532	1884	2873
2029	9.3%	28.0%	39.0%	583	2077	3155
2030	9.3%	28.0%	39.0%	633	2272	3441

Figure C-23: Assumed Market Penetration Rates for New PHEV



Plug-in hybrid electric vehicles were assumed to have an average energy requirement of 0.3 KWh/mile. The analysis focused on a composite of three types of cars: a compact sedan, a mid-size sedan, and a mid-size SUV ranging from 0.26 to 0.46 KWh/mile to create a “typical” PHEV. For this composite vehicle, a Lithium-ion battery sized to 10 kilowatt hours is assumed to power the vehicle. It was also assumed that the energy efficiency of the vehicle would improve at a rate of 5 percent per year.

These vehicles are assumed to travel 33 miles per day, the current average. The battery recharge profile for PHEV is important in order to estimate their demand on the electric grid. It was assumed that 95 percent of cars would be charged between 7 p.m. and 7 a.m., and 5 percent of the vehicles would be charged between 8 a.m. and 6 p.m. Recharging at 110 volt, 15 amp was assumed to take eight hours or less; at 220 volt, 30 AMP, the vehicle would be charged in less than two hours. The current average efficiency of gasoline-powered fleet vehicles is assumed to be 20.2 MPG and improving to 35 MPG by 2020. Based on these assumptions, electricity demand for each scenario was projected. The following figure shows the annual energy and peak and off-peak demand requirements of plug-in hybrid vehicles in the Northwest.

Given these assumptions, plug-in electric vehicles are forecast to increase the regional load between 100 to 550 average megawatts by 2030.   The increase in load would be gradual and would have a minimal impact on regional load in the first 5 to 10 years of introduction into the market. Their impact on system load would be greater during off-peak hours, given the recharge assumption. It is projected that off-peak loads would increase by 200-1,000 megawatts. The impact of PHEV on system peak is projected to be much smaller, 5-25 megawatts, given the assumption that only 5 percent of vehicles will recharge during the peak period.

Figure C-24: Projected Load from Plug-in Hybrid Vehicles

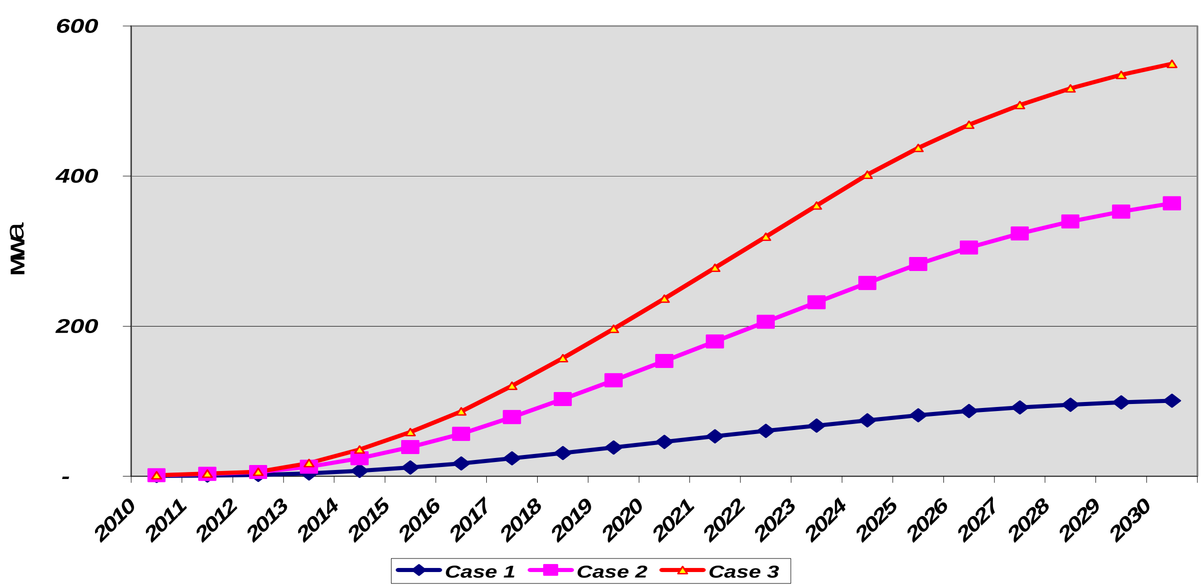


Figure C-25: Project Off-peak Load from Plug-in Hybrid Vehicles