CHAPTER 7: ELECTRICITY DEMAND FORECAST

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Throughout this chapter the demand forecast is presented as a range. This is done to reinforce the fact that the future is uncertain. The Council's planning process does not use a single deterministic future to drive the analysis. Rather, the stochastic variation introduced in the Regional Portfolio Model tests a wide range of future uncertainties in load, fuel prices etc.

The forecast for the Bonneville Power Administration's load and resource obligations is presented in Chapter 5.

KEY FINDINGS

Pacific Northwest consumers used 19,400 average megawatts or 170 million megawatt-hours of electricity in 2013. Without development of conservation beyond that projected to result from changes in retail electricity prices, the Council forecasts regional electricity demand will grow between 20,600 and 23,600 average megawatts by 2035.[1] Regional demand is expected to increase by 1,800 to 4,400 average megawatts from 2015 to 2035 with an annual increase of 90 to 220 average megawatts per year. This translates to a growth rate of 0.5 to 1.0 percent per year. The regional peak load for power, which typically occurs in winter, is forecast to grow from 30,000 to 31,000 megawatts in 2015 to 31,600 to 35,600 megawatts by 2035. This equates to an average annual growth rate of 0.4 to 0.8 percent. Cost-effective efficiency improvements identified in this Seventh Power Plan are anticipated to meet most if not all of this projected growth under most future conditions.

The slow pace of growth in electricity demand is unprecedented. Lower forecast growth in demand is due to projected significant improvements in federal appliance standards and to a much lesser extent, the growth in distributed generation at customer sites (e.g. rooftop solar photovoltaics [PV]). After accounting for the impact of new cost-effective conservation that should be developed over the 20-year period covered by the Seventh Plan, the need for additional generation is forecast to be quite small compared to historical experience. While annual electricity demand is forecast to grow slowly, summer-peak demand continues to grow and may equal winter-peak demand near the end of this 20-year plan.

Unlike most of the rest of the nation, the Northwest has historically been a winter-peaking power system. However, largely due to the increased use of air conditioning, the difference between winter- and summer-peak loads is forecast to shrink over time. Assuming normal weather conditions, winter-peak demand in the Seventh Power Plan is projected to grow from 30,000 to 31,000 megawatts in 2015 to around 31,600 to 35,600 megawatts by 2035. Summer-peak demand is forecast to grow faster than winter peak. Summer peak is forecast to grow from 27,000 to 28,000 megawatts in 2015 to 30,600 to 33,600 megawatts by 2035. The average annual growth rate for winter-peak demand is forecast to be 0.4 to 0.8 percent per year while the annual growth rate for summer-peak demand is forecast to grow at a slightly faster pace of 0.7 to 1.0 percent per year. As a result, by 2035 the gap between summer-peak load and winter-peak load will have narrowed considerably from about 3,000 megawatts to between 1,000 to 2000 megawatts.

[1] Throughout this chapter the amount of electricity used by consumers is referred to as either electricity ***demand*** or ***sales.*** Electricity ***load*** refers to the amount of electricity produced at generation facilities and includes transmission and distribution system losses.

INTRODUCTION

Background

It has been nearly 33 years since the Council adopted its first power plan in 1983. Since then, the region's energy environment has undergone many changes. In the decade prior to the passage of the Northwest Power Act, total regional electricity demand was growing 3.5 percent per year. Demand growth, excluding the direct service industries or DSIs (i.e., the aluminum and chemical companies directly served by Bonneville), grew at an annual rate of 4.3 percent. In 1970, regional demand was about 11,000 average megawatts and during that decade demand grew by nearly 4,700 average megawatts. As shown in Figure 7 - 1, during the 1980's, the pace of demand growth slowed significantly. Nevertheless, electricity demand continued to grow at about 1.5 percent per year, totaling about 2,300 average megawatts over the decade. In the 1990's another 2,000 average megawatts was added to the regional demand, resulting in a growth rate of 1.1 percent annually in the last decade of the 20th century. However, since 2000, regional electricity demand has actually declined. As a result of the West Coast energy crisis of 2000-2001 and the recession of 2001-2002, regional demand decreased by 3,700 average megawatts between 2000 and 2001. A significant factor for reduction in demand was the closure of many of the industrial plants (i.e., the Direct Service Industries) served by the Bonneville Power Administration. Regional demand for electricity in the Northwest has still not returned to the level experienced in 2000 prior to the West Coast energy crisis. As can be seen in Figure 7 - 1, 2014 regional electricity demand (i.e. sales) were still below the sales in 2000.

Figure 7 - 1: Total and Non-DSI Regional Electricity Sales (aMW)

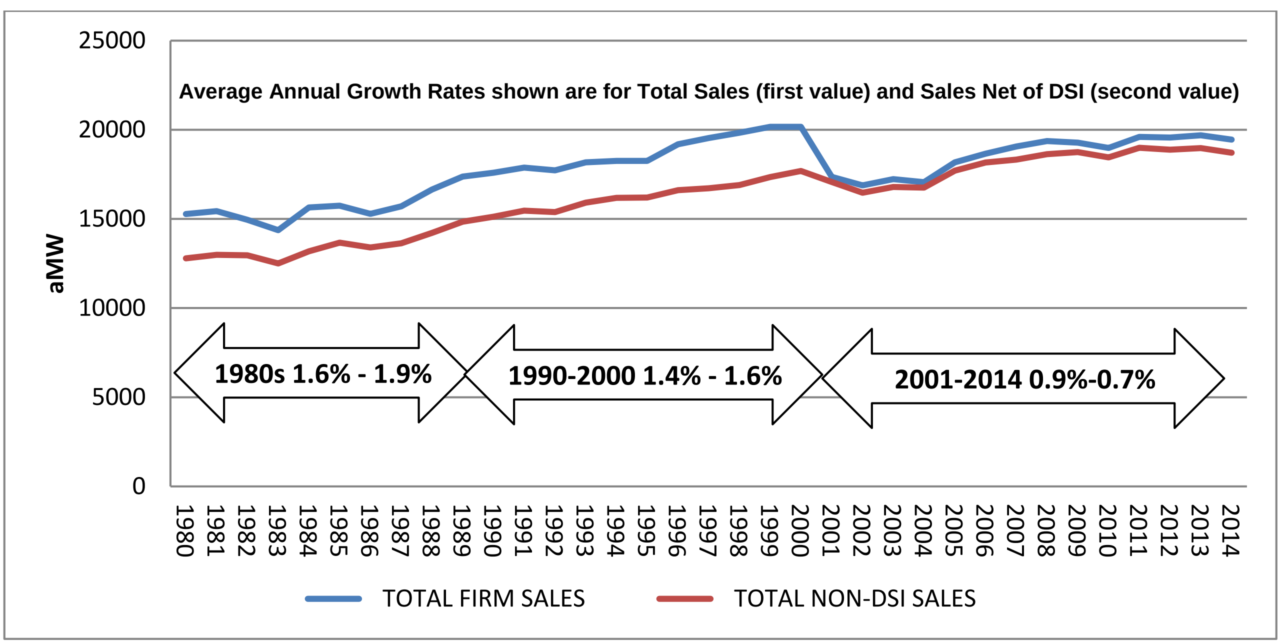
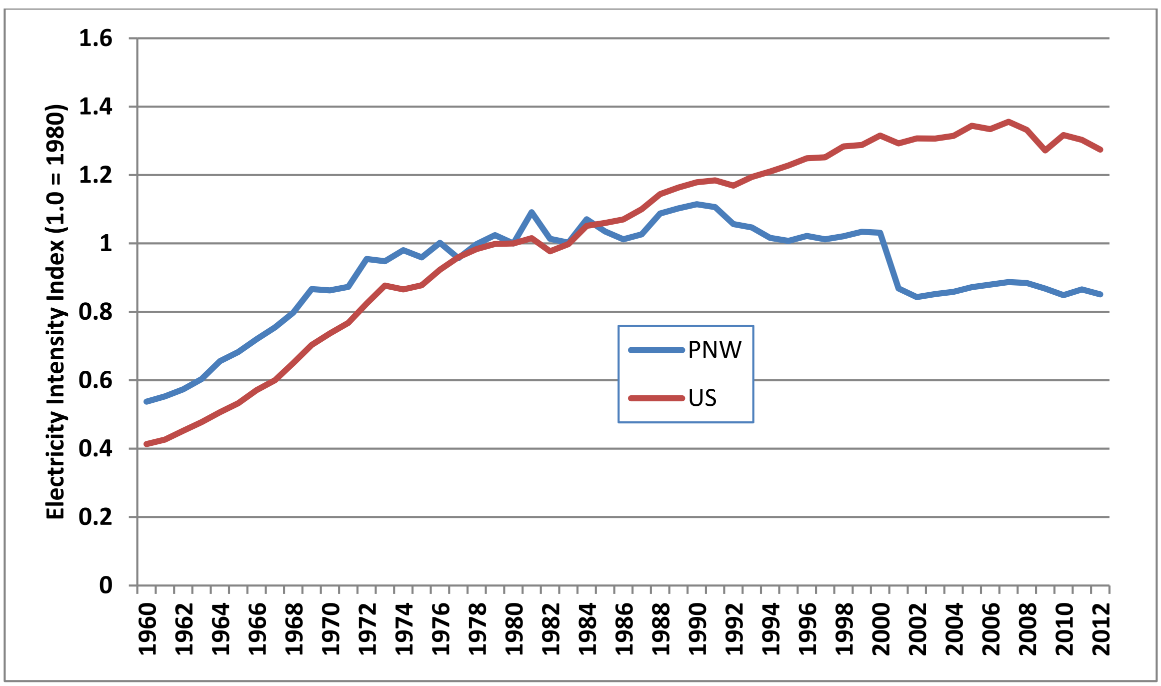


Table 7 - 1: Average Annual Growth of Total and Non-DSI Regional Electricity Sales

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%
2007-2014	0.3%	0.3%

The dramatic decrease in electricity demand over roughly the last four decades shown in Table 7 - 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 electricity-intensive activities and improvements in energy efficiency. As shown in Figure 7 - 2, in the Pacific Northwest, electric intensity in terms of use per capita increased between 1980 and 1990, but has been declining since 1990. This shift reflects industry changes in the region (e.g., the significant drop in electricity intensity per capita between 2000 and 2001 was due to the closure of many of the DSIs), increasing electricity prices, decreases in the market share of electric space and water heating and regional and national conservation efforts.

Figure 7 - 2: Trends in Electricity Intensity Per Capita 1960-2012 (index to 1980)



SEVENTH POWER PLAN DEMAND FORECAST

The Pacific Northwest consumed 19,400 average megawatts or 172 million megawatt-hours of electricity in 2013. Without the development of conservation beyond that projected to result from changes in retail electricity prices, the Council forecasts regional electricity demand to grow to 20,600 to 23,600 average megawatts by 2035. After accounting for distribution and transmission system losses, regional loads, measured at the generation site, are expected to increase by 2,200 to 4,800 average megawatts between years 2015 and 2035. This translates to an average increase of 90 to 220 average megawatts per year or a growth rate of 0.5 to 1.0 percent per year. The regional peak load for power, which typically occurs in winter, is forecast to grow from 30,000 to 31,000 megawatts in 2015 to around 31,600- 35,600 megawatts by 2035. This equates to an average annual growth rate of 0.4 to 0.8 percent.

Unlike most of the rest of the nation, the Northwest has historically been a winter-peaking power system. However, largely due to the increased use of air conditioning, the difference between winter- and summer-peak loads is forecast to shrink over time. Assuming normal weather conditions, winter-peak demand is projected to grow from 30,000 to 31,000 megawatts in 2015 to 31,600 to 35,600 megawatts by 2035. Summer-peak demand is forecast to grow faster than winter peak demand. Summer peak demand is forecast from 27,000 to 28,000 megawatts in 2015, to 30,600 to 33,600 megawatts by 2035. The average annual growth rate for winter-peak demand is forecast to grow at 0.4 to 0.8 percent per year while the annual growth rate for summer-peak demand is forecast to grow at a slightly faster pace of 0.7 to 1.0 percent per year. As a result, by 2035 the gap between summer-peak load and winter-peak load will have narrowed considerably from about 3,000 megawatts to 1,000 - 2000 megawatts.

Demand Forecast Range

Forecasting future electricity demand is difficult because there is considerable uncertainty surrounding economic growth and demographic variables (e.g. net migration), natural gas prices and other factors that significantly affect electricity demand. To evaluate the effect of these economic and fuel-price uncertainties in the Seventh Power Plan, the Council developed a range of demand forecasts. The Seventh Power Plan’s low to high range is based on IHS-Global Insight’s Q3 2014 range of national forecasts. IHS-Global Insight is a well-known national consulting company. To forecast electricity demand under each scenario, the Council used the economic assumptions from the IHS-Global Insight’s forecast. Economic variables presented in Appendix B, show the range of values for key economic assumptions used for each scenario modeled. The resulting range for the most significant economic drivers of growth in electricity demand is shown in Table 7 - 2.

Table 7 - 2: Forecast Range for Key Economic Drivers of Growth in Demand

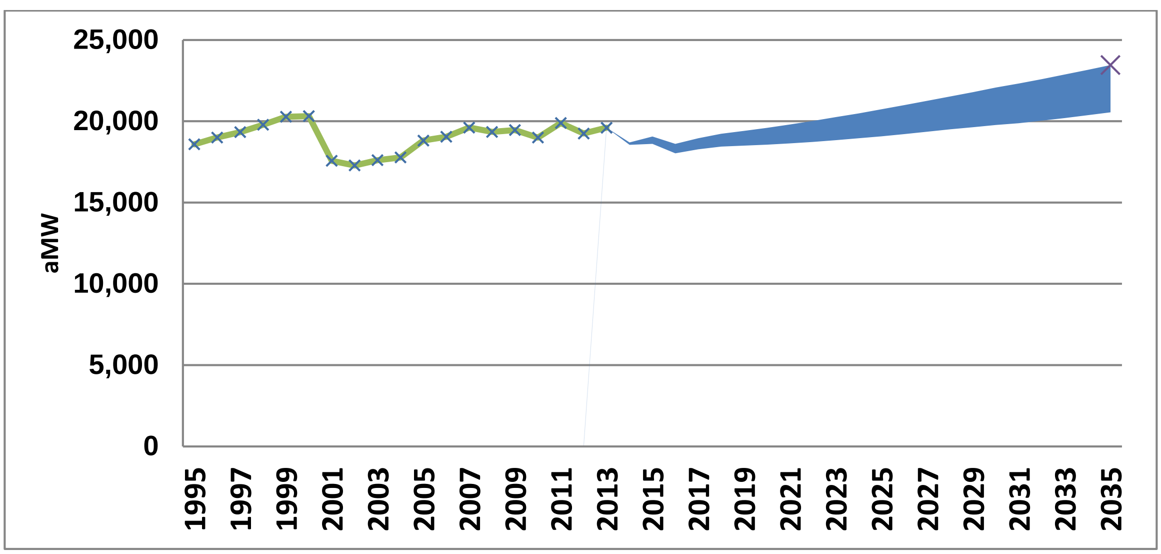
Average Annual Growth Rates over next 20 years

	Medium case	High case	Low case
Residential units	1.18%	2.0%	0.08%
Commercial floor space	1.11%	2.1%	0.67%
Industrial output ($2012)	1.56%	2.4%	0.95%
Agricultural output ($2012)	0.81%	2.0%	0.26%

Two alternative economic scenarios were developed for the Seventh Power Plan. The most likely range of economic growth is 0.6 to 1.1 percent per year. The low scenario growth rate of 0.6 percent per year reflects a prolonged recovery from the recession, and the high scenario growth rate of 1.1 percent per year reflects a more robust recovery and future growth.

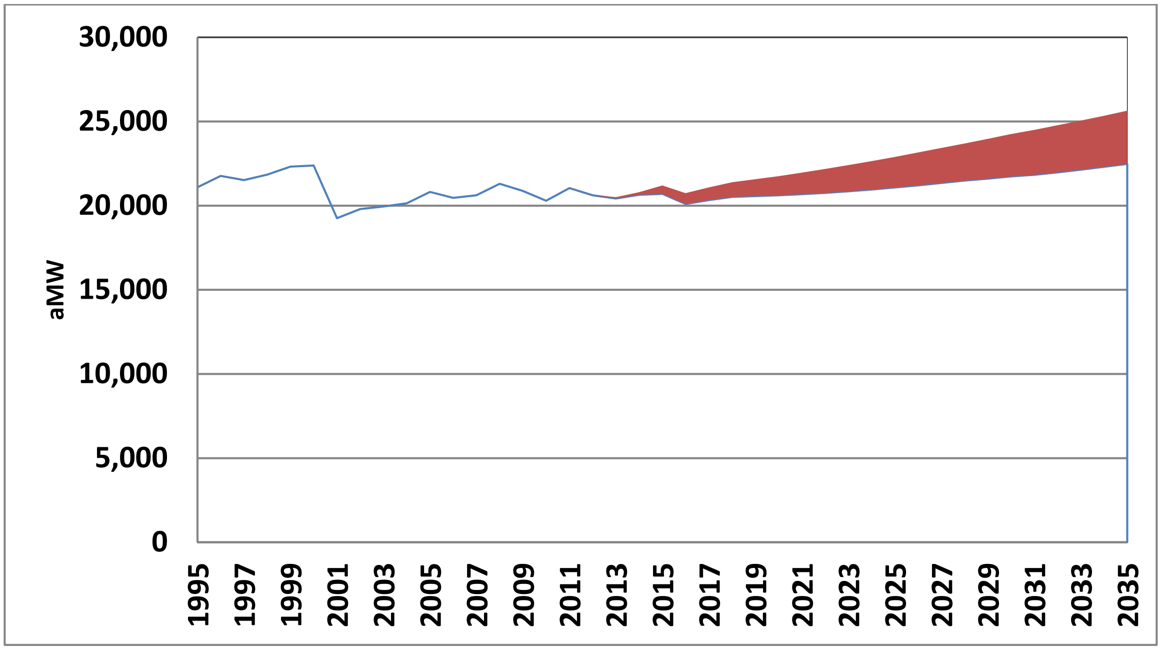
Figure 7 - 3 shows the Seventh Power Plan's electricity demand forecast range through 2035 and historical regional electricity demand since 1995. Under the low forecast, regional demand for electricity by 2030 returns to the level of regional demand prior to the West Coast energy crisis in 2000. Under the high forecast, electricity demand increases much more quickly, so that in 2020 demand is roughly equivalent to regional demand in 2000. Figure 7 - 4 shows this same information, but includes line-losses. In all of its resource planning work, Council uses loads at the point of generation; this is to properly compare options on supply and demand side (efficiency or demand response).

Figure 7 - 3: Historical and Seventh Power Plan Electricity Demand (sales) Forecast Range (aMW)*



* Demand (sales) figures include electricity use by consumers and exclude transmission and distribution losses. Load figures are measured at the point of generation (busbar).

Figure 7 - 4: Historical and Seventh Northwest Power Plan Load Forecast (aMW) Including Line-Losses



Sector Level Load Forecast

The Seventh Power Plan forecasts loads to grow at an average annual rate of 0.6 to 1.1 percent during the 2015 through 2035 period. Table 7 - 3 shows the actual 2012 regional electricity loads and forecast future loads for selected years, as well as the corresponding annual growth rates. These load forecasts do not include any new conservation initiatives. Note that changes in sector level loads are shown as a range, reflecting the uncertainty inherent in forecasts. Average Annual Growth Rate (AAGR) is shown in the last column.

Table 7 - 3: Load Forecast By Sector (aMW)

Sector	2012	2015	2020	2035	Average Annual Growth Rate 2015-2035
Residential	8,313	8,339 – 8,375	8,100 – 8,400	8,100 – 9,300	-0.2% - 0.5%
Commercial	6,377	6,700 – 6,900	6,900 – 7,200	8,000 – 8,600	0% - 1.1%
Industrial	5,618	5,350 – 5,650	5,400 – 5,900	6,100 – 7,200	0.7% - 1.2%
Transportation	8	26 - 31	67-147	162 - 623	10% to 16%
Street lighting	348	351	354	361	0.1%

From 2015 to 2035, the residential sector electricity load is forecast to grow between negative 0.2 to positive 0.5 percent per year. On average this translates to an annual reduction in residential sector loads of about 14 average megawatts to an annual increase of about 50 average megawatts each year. Modest growth in the residential sector reflects substantial reductions in load due to federal standards, increased on-site solar PV generation, as well as slower growth in home electronics.

Commercial sector electricity loads are forecast to grow by 0.9 to 1.1 percent per year between 2015 and 2035. This translates to a commercial sector load increase from 6,700-6,900 average megawatts in 2015 to 8,000-8,600 average megawatts by 2035. The slower commercial sector load growth, compared to the Sixth Power Plan is due to the presence of federal standards, slower growth in new floor space, and greater efficiency in lighting technology, primarily from using solid state lighting (i.e., LEDs). On average, this sector adds 64 to 85 average megawatts per year to regional electricity loads.

Industrial sector loads are forecast to grow 0.7 to 1.3 percent annually. Industrial loads are forecast to grow from 5350-5650 average megawatts in 2015 to 6100-7200 average megawatts by 2035. This translates to 35-77 average megawatts per year. Industrial loads in the Northwest have been slow to return to levels experienced before the West Coast energy crisis. The resource-based industries (e.g. pulp and paper) are being replaced with high-tech industries. For example, one segment of the industrial sector that has experienced significant growth is that of custom data centers. Although these businesses do not manufacture a tangible product, they are typically classified as industrial customers because of the amount of electricity they use. The Council's estimates show that there are currently 350 to 450 average megawatts of connected load for these businesses. Loads from these data centers are forecast to increase to between 400 and 900 megawatts by 2035.

In the Seventh Power Plan, the direct service industry's (DSI) load was changed from the draft to final version of the Plan. In November 2015, Alcoa announced temporary closure of their smelting operations in the state of Washington. The DSI load which was assumed to be around 700-800 average megawatts for the forecast period post-2018 was lowered by about 400 aMW for the final plan. Although the portion of Alcoa's Wenatchee aluminum smelter that is served from non-Bonneville sources is not technically a DSI (it is not served by Bonneville), that load is included in the DSI category in the Seventh Power Plan to permit comparison with prior plans.

The transportation sector's electricity load is expected to grow substantially as the number of plug-in electric (all electric or hybrid electric) vehicles increases. The Council's Seventh Power Plan projects loads in this sector to increase from 8 average megawatts in 2015 to 160-620 average megawatts by 2035.

Future Trends for Plug-in Hybrid or All-Electric Vehicles

Concern for the environment and volatile gasoline prices have created great interest in electric vehicles (EVs), both all-electric and plug-in hybrids. The most recent data from the Environmental Protection Agency (EPA) show that annual sales increased from about 350 vehicles in December 2010 to sales of over 22,600 vehicles as of July 2015. This is significant given the financial crisis the U.S. auto industry went through during the recession. The number of EV branded vehicles increased from 2 in 2010 to 23 in 2014. Cumulatively, from 2010 through February of 2015, over 300,000 EVs were sold nationwide.

Average load from EVs is projected to increase from the current estimated 10 average megawatts in 2014 to between 160 and 650 average megawatts by 2035. Based on the currently observed hourly pattern of charging, most of the charging happens at night during off-peak (post-midnight) hours. Therefore, the impact of EV charging on off-peak loads is significantly higher than on-peak loads. Off-peak demand is forecast to be in the range of 250 to 1200 megawatts, while peak period demand for EV charging is forecast to be between 7 and 32 megawatts. Additional details/analysis on electric vehicles can be found in Appendix E.

Distributed Solar Photovoltaics

Distributed solar or "rooftop solar" using photovoltaic (PV) panels is a relatively new entry into the energy market in the Northwest. Deep declines in PV module prices, availability of third-party financing and other financial incentives have resulted in significant increases in the installation of these distributed generators during the past five years. The Council estimates that by 2015 there will be over 110 megawatts of Alternating Current (AC) nameplate capacity installed in the region, generating the equivalent of about 17 to 18 average megawatts of energy and providing about 18 megawatts of summer peak load reduction.[2] In the Seventh Power Plan, the Council has incorporated the impact of market-driven rooftop solar power generation into its long-term forecast model. Therefore, the load forecasts shown for each sector are net of the on-site generation from solar PV. The contribution to system average and system peak from solar PV installs is estimated taking into account coincident factors of mapped solar generation and system load.

To forecast market share for electricity generated from distributed solar systems, the Council developed an estimate of the relationship between the relative cost of system installs versus the retail cost of electricity. This relationship between inter-fuel competition between electricity and distributed solar PV was then used to forecast the future market share of distributed solar systems. The Council forecast of distributed solar PV adoption assumes a 53% reduction in cost between 2012 and 2030.[3] By 2035, the Council forecasts that 500 to 1,400 megawatts of solar PV systems will be installed in the region. On an annual basis, the energy generated from these distributed PV systems is forecast to reduce regional loads by 80 to 220 average megawatts. In addition, these distributed solar PV systems also reduce winter and summer peak loads. Summer peak impacts from distributed solar PV are forecast to be lower by as much as 600 megawatts by 2035.

To calculate the impact that distributed solar PV generation would have on system average and system peak loads, the Council used hourly solar PV generation profiles for 16 locations in the Northwest available from the National Renewable Energy Laboratory's (NREL) *PV Watts* program. A more detailed discussion of rooftop solar PV generation appears in Appendix E- Demand Forecast, and the companion technical workbook showing year by year assumptions.

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[2] For a more detailed discussion of sector-level sales and loads please see Appendix E.
[3] Appendix H contains additional discussion of the forecast decline in PV module costs.

A companion spreadsheet for Seventh Power Plan demand forecast data is available at the following link: http://www.nwcouncil.org/energy/powerplan/7/technical
(Regional and state level details on economic drivers, fuel prices, demand and load forecast)

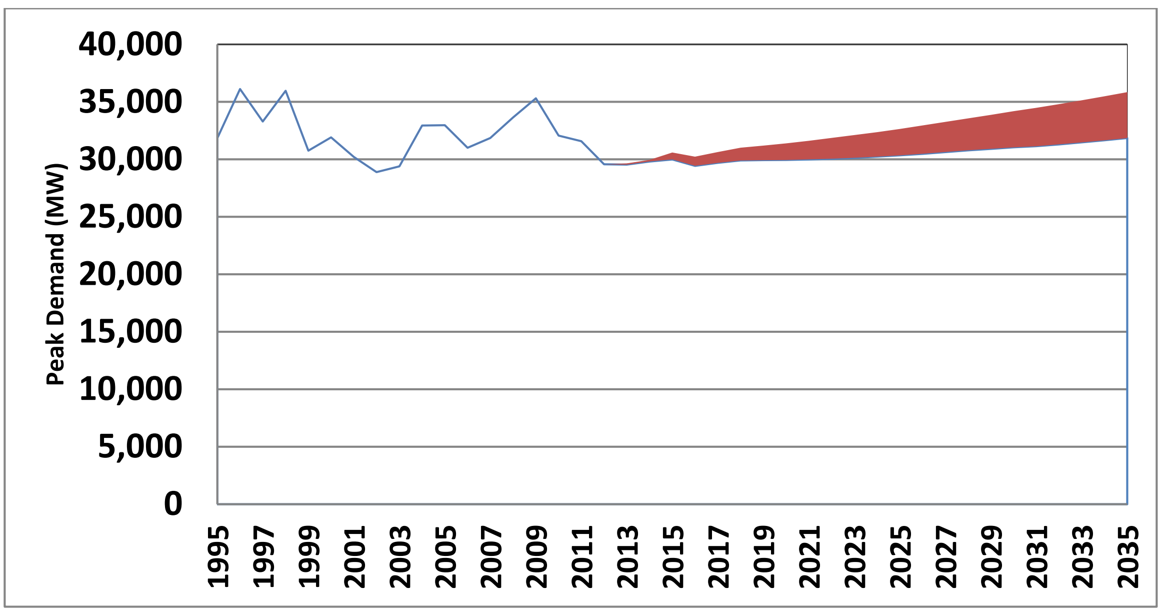
PEAK LOAD FORECAST

Peak Load

The regional peak load for power, which has historically occurred in winter, is expected to grow at an average annual growth rate of 0.3 to 0.8 percent from 30,000 to 31,000 megawatts in 2015 to 31,900-35,800 megawatts by 2035. Assuming historical normal temperatures, the region is expected to remain a winter-peaking system, although summer peaks are expected to grow faster than winter peaks, significantly narrowing the gap between summer-peak load and winter-peak load. By the end of the forecast period the difference between summer and winter peak is forecast to range from 1,000 to 2,000 megawatts. Summer peaks are projected to grow from 27,000 to 28,000 megawatts in 2015 to 30,500 to 33,800 megawatts in 2035.

The forecast for regional peak load assumes normal weather conditions. There are no assumptions regarding temperature changes incorporated in the Seventh Power Plan's load forecast. Climate change sensitivity analysis, discussed in Appendix M, projects that there could be an additional 4,000 megawatts of summer peak load added by 2035 due to climate change. Figure 7 - 5 shows estimated actual peak load for 1995-2012, as well as the forecasted peak load range for 2013-2035.

Figure 7 - 5: Historical and Forecast Regional Winter Peak Load (MW)



Alternative Load Forecast Concepts

Three different but related load forecasts are produced for use in the Council's resource planning process. The first of these forecasts is called a "price-effect" demand forecast, which is the forecast that has been presented up to this point. The price-effect forecast is the official demand forecast required by the Northwest Power Act.

The price-effect demand forecast reflects customers' choices in response to electricity and fuel prices and technology costs, without any new conservation resources. However, expected savings from existing and approved codes and standards are incorporated in the price-effect forecast, consequently reducing the forecast and removing the potential from the new conservation supply curves.

To eliminate double-counting the conservation potential, the load-forecasting model produces another long-term forecast, labeled Frozen-Efficiency forecast.

Frozen-Efficiency (FE) demand forecast, assumes that the efficiency level is fixed or frozen at the base year of the plan (in the case of the 7th Plan, base year is 2015). For example, if a new refrigerator in 2015 uses 300 kilowatt hours of electricity per year, in the FE forecast this level of consumption is held constant over the planning horizon. However, if there is a known federal standard that takes effect at a future point in time (e.g., 2022), which is expected to lower the electricity consumption of a new refrigerator to 250 kilowatt hours per year then post-2022 a new refrigerator's consumption is reduced to this new lower level in the FE demand forecast. In this way, the difference in consumption, 50 kilowatt hours, is treated as a reduction in demand rather than considered as a future conservation potential. This forecast approach attempts to eliminate the double-counting of conservation savings, since estimates of remaining conservation potential use the same baseline consumption as the demand forecast. That is, the frozen technical-efficiency levels are the conservation supply model's starting point. Frozen-efficiency load forecasts are inputs to the Regional Portfolio Model for use in resource strategy analysis.

Once the Council adopts a resource strategy for the Seventh Plan including regional conservation goals, a third demand forecast is produced. This forecast, referred to as the **Sales Forecast** is the Frozen Efficiency forecast net of cost-effective conservation and demand response resource savings contained in the plan's resource strategy. The level of demand response called for in the plan, which has the impact of lowering peak loads is shown in table 7-5**.** The Sales Forecast represents the expected sales of electricity after all cost-effective conservation has been achieved[4]. It incorporates the effects of electricity prices and the cost-effective conservation resources that are selected by the Regional Portfolio Model. The sales forecast captures both price-effects and potential "take-back" effects (increased use in response to the lower electricity bills as efficiency increases). It should be pointed out that although the label for this forecast is "sales," it is presented at both the consumer's meter and at the generator site by including transmission and distribution system losses.

The difference between the Price-Effect and Frozen-Efficiency forecasts is relatively small. The Frozen-Efficiency forecast is typically slightly higher than the Price-Effect forecast. For the Seventh Power Plan the two forecasts differ by 60 to 600 average megawatts by 2035 depending on the underlying economic growth scenario. The following table and graphs present a comparison of these forecasts.

[4] The "sales" forecast, as well as price-effect and frozen efficiency, can be measured at a consumer or generator site (which would include transmission and distribution losses). Demand is measured at the customer site while load is measured at the generator site.

Table 7 - 4: Range of Alternative Load Forecasts (as measured at the point of generation)

	Forecast	Scenario	2016	2021	2026	2031	2035	AAGR 2016-2035
Energy (aMW)	Price-effect	Low	20,100	20,680	21,205	21,829	22,482	0.56%
Energy (aMW)	Price-effect	High	20,743	21,960	23,157	24,498	25,638	1.06%
Energy (aMW)	FE	Low	20,097	20,682	21,219	21,866	22,542	0.58%
Energy (aMW)	FE	High	20,752	22,031	23,341	24,858	26,185	1.17%
Energy (aMW)	Sales	Low	19,926	19,292	18,209	17,862	18,356	-0.41%
Energy (aMW)	Sales	High	20,575	20,592	20,171	20,551	21,655	0.26%
Winter Peak (MW)	Price-effect	Low	29,438	29,990	30,482	31,139	31,854	0.40%
Winter Peak (MW)	Price-effect	High	30,237	31,617	32,946	34,481	35,843	0.85%
Winter Peak (MW)	FE	Low	29,436	30,000	30,518	31,221	31,983	0.42%
Winter Peak (MW)	FE	High	30,252	31,734	33,246	35,057	36,708	0.97%
Winter Peak (MW)	Sales	Low	28,815	27,152	24,980	23,782	23,847	-0.94%
Winter Peak (MW)	Sales	High	29,608	27,781	26,322	25,433	26,065	-0.64%
Summer Peak (MW)	Price-effect	Low	26,484	27,285	28,179	29,311	30,494	0.71%
Summer Peak (MW)	Price-effect	High	27,364	28,846	30,384	32,187	33,805	1.06%
Summer Peak (MW)	FE	Low	26,478	27,278	28,188	29,346	30,553	0.72%
Summer Peak (MW)	FE	High	27,382	28,980	30,737	32,876	34,849	1.21%
Summer Peak (MW)	Sales	Low	25,805	24,781	23,839	23,957	24,579	-0.24%
Summer Peak (MW)	Sales	High	26,676	25,458	26,661	25,502	26,678	0.00%

Impact of Demand Response on System Peak

Up to this point in our discussions of alternative load forecasts we have focused on the impact of energy efficiency programs on loads. The Seventh Power Plan also calls on regional utilities to acquire demand response resources, which can be called upon during peak periods. Forecasted summer and winter peak loads under the "Sales" scenario are expected to be reduced by the target amount of demand response shown in the table below.

Table 7 - 5: Range of Demand Response Resource Expected to be used (MW)

	Forecast	Scenario	2016	2021	2026	2031	2035
Winter	Sales	Low	501	906	906	940	1347
Winter	Sales	High	1002	1852	1947	2440	3036
Summer	Sales	Low	468	827	827	860	1282
Summer	Sales	High	468	1728	1838	2380	2932

Figure 7 - 6: Price-Effects Forecast Range– Energy

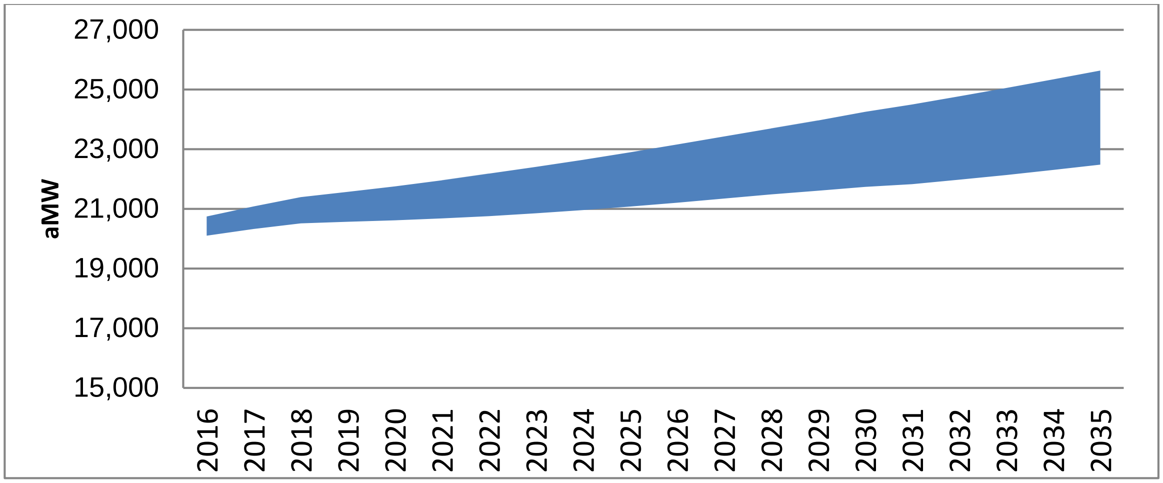


Figure 7 - 7: Frozen- Efficiency Forecast Range– Energy

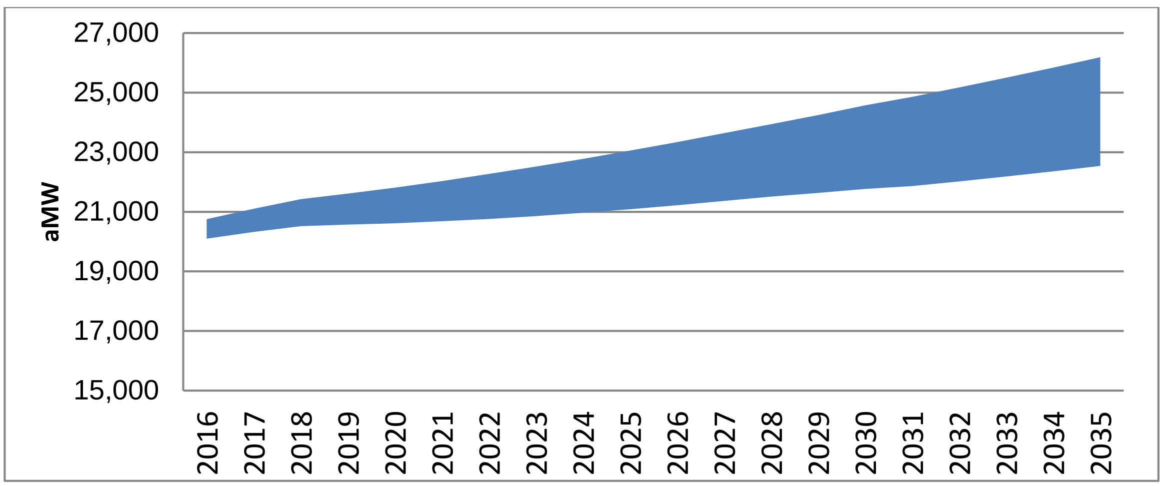


Figure 7 - 8: Sales (Net Load After Conservation) Forecast Range – Energy

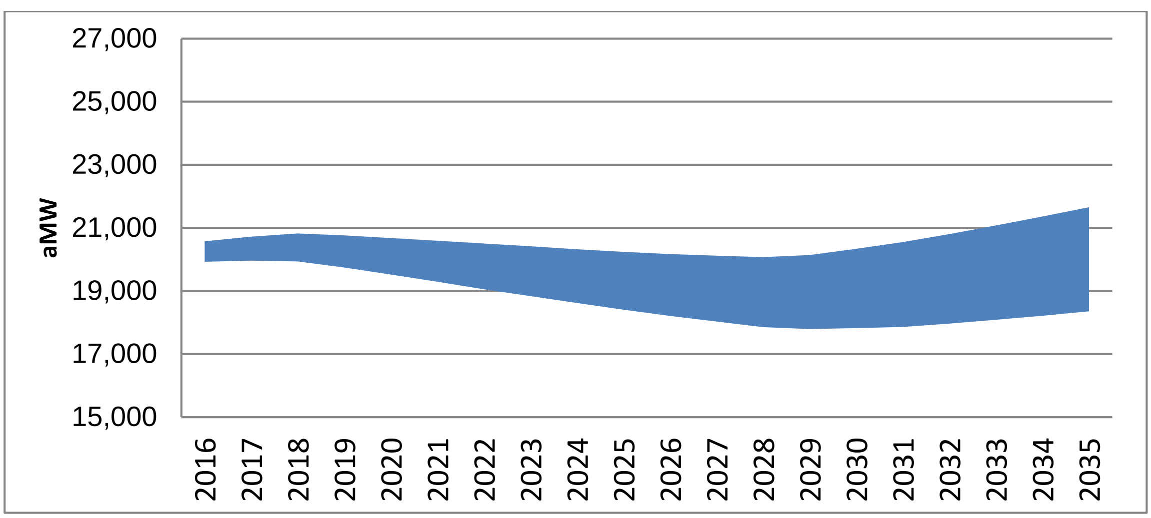


Figure 7 - 9: Price-Effects Forecast Range - Winter Peak

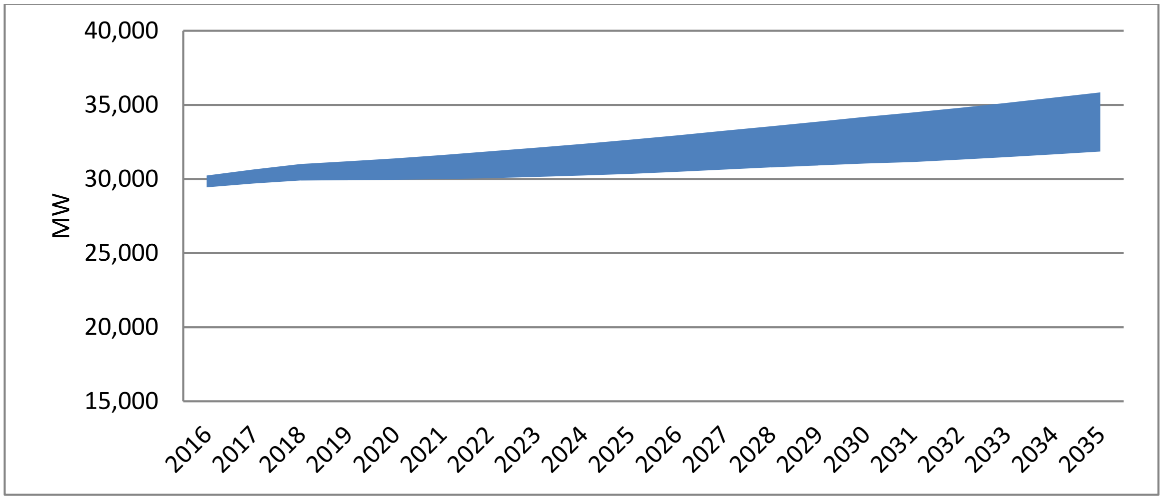


Figure 7 - 10: Frozen- Efficiency Forecast Range – Winter Peak

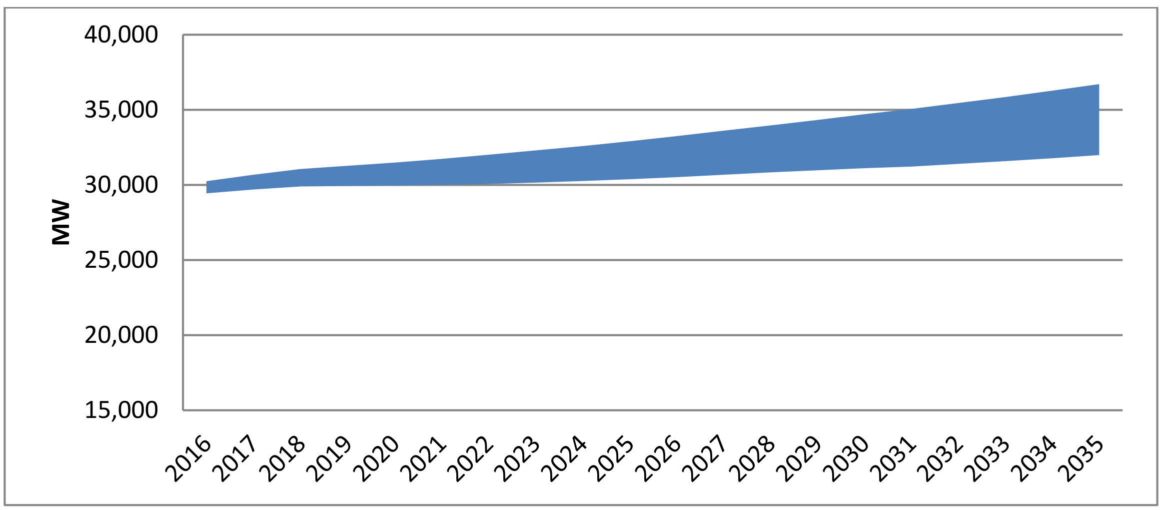


Figure 7 - 11: Sales (Net Load After Conservation and DR) Forecast Range – Winter Peak

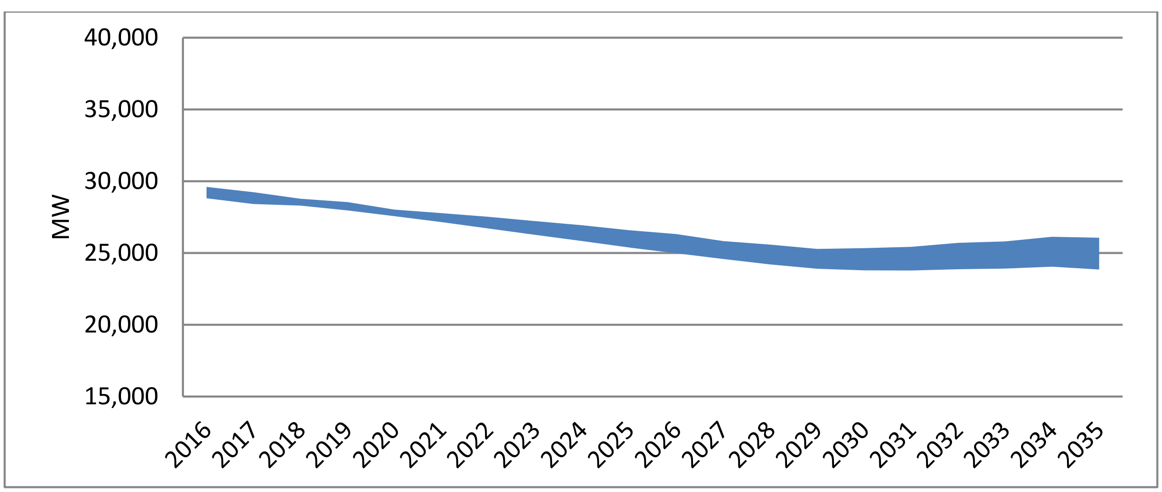


Figure 7 - 12: Price-Effects Forecast Range – Summer Peak MW

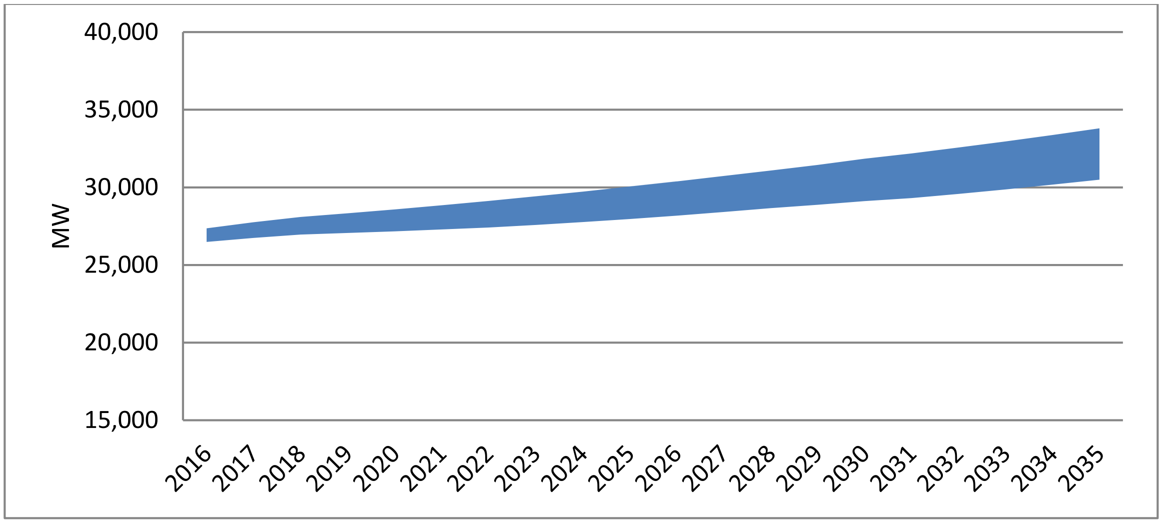


Figure 7 - 13: Frozen- Efficiency Forecast Range – Summer Peak

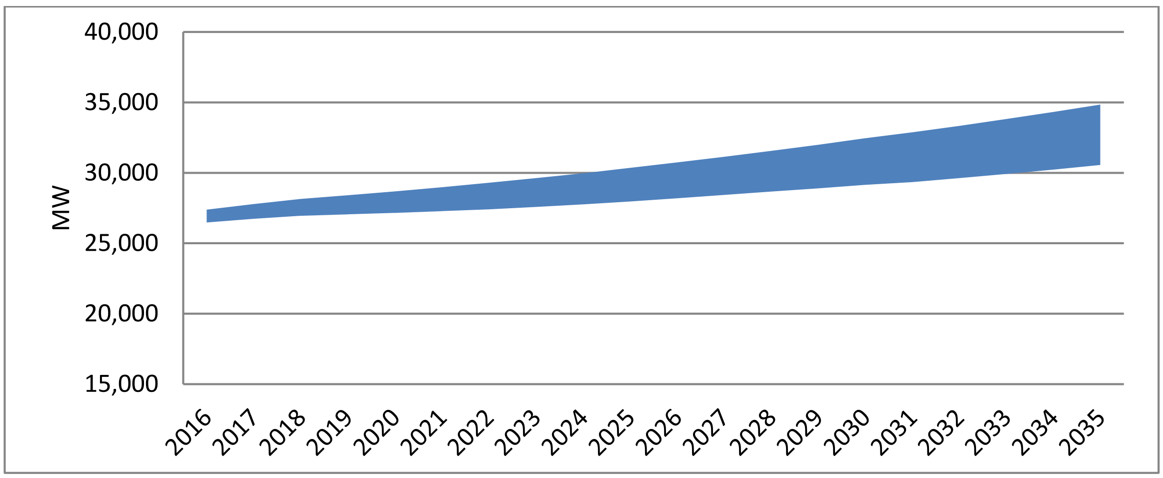
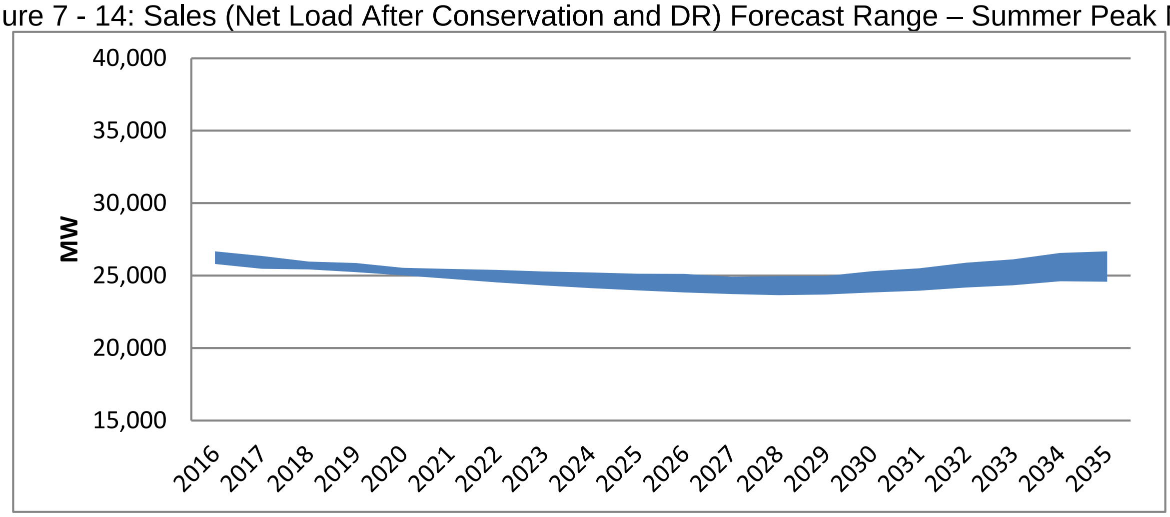


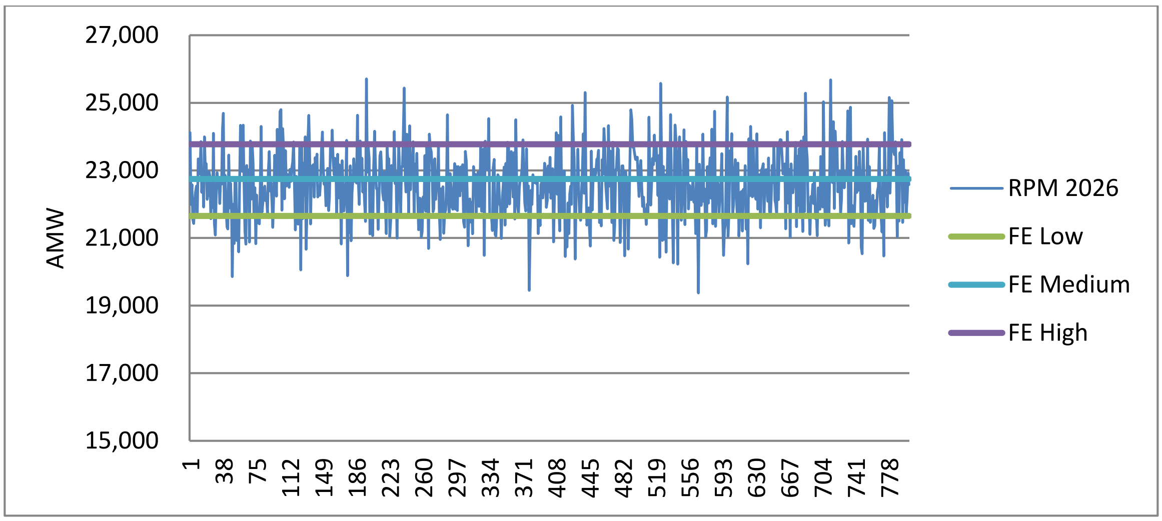
Figure 7 - 14: Sales (Net Load After Conservation and DR) Forecast Range – Summer Peak MW



Regional Portfolio Model (RPM) Loads

While the Council develops three types of long-term forecasts, the quarterly Frozen-Efficiency load forecast is the forecast used in the RPM for developing alternative future load-growth paths. The RPM takes the Frozen-Efficiency load forecast and introduces short-term excursions that simulate such events as business and energy commodity price cycles and load variations that could be caused by weather events. Figure 7 - 15 shows the 800 future load paths evaluated in the RPM for a year 2026. As can be observed, in some futures RPM loads are above the Frozen Efficiency forecast range for 2026 and in some futures RPM loads are below the Frozen Efficiency forecast range.

Figure 7 - 15: RPM Comparison of 800 future load paths and range of loads from Frozen Efficiency Load Forecast for 2026



A more refined method for estimating single-hour peak values was created to provide the RPM with expected hourly peak for each quarter. This methodology consists of using the average quarterly weather-normalized energy from the long-term model and the hourly temperature sensitive load multiplier from the Council's short-term model and running a Monte Carlo simulation on the loads under the weather conditions of the past 86 years (1929-2013) to create an expected hourly load for each quarter. The process used to convert the Frozen Efficiency forecast to the specific 800 futures used in the RPM is discussed in more detail in Chapter 15 and in Appendix L.

Direct Use of Natural Gas

As part of developing the Seventh Power Plan, the Council evaluated whether or not a direct intervention in the markets where natural gas is thermodynamically or economically more efficient, would be necessary. In Appendix N of this plan, the Council presents findings on the economics of direct use of natural gas to displace electrical residential space and/or water heating. The Council performed an updated analysis (discussed in Appendix N) that focused on one of the eight market segments identified in the Council's 2012 assessment as providing both consumers and the region with economic benefits through conversion from electricity to natural gas.

The updated analysis estimates the share of single family homes with electric water heating and natural gas space heating that would find economic benefits by conversion to natural gas water heating when their existing water heater requires replacement. Two estimates were made. The first, which is comparable to the Council's 2012 analysis, assumes that in all cases the most economical (i.e. lowest life-cycle cost) water heating fuel type would be selected. The second case, assumes that consumers would not always select the lowest cost option due to other "non-economic" barriers to conversion. This case found that fewer, but still a significant share, of households would alter their existing water heating fuel. Moreover, based on historical fuel selection trends, it appears that natural gas continues to gain space and water heating market share while electricity's share of these end uses continues to decrease. The Council's analysis concluded that market mechanisms are operating efficiently and that no market intervention is needed. Further details on the Seventh Power Plan Direct Use of Natural Gas can be found in Appendix N.