Chapter 3: Electricity Demand Forecast

SUMMARY OF KEY FINDINGS

The Pacific Northwest consumed 19,000 average megawatts or 166 million megawatt-hours of electricity in 2007. That demand is expected to grow to 25,000 average megawatts by 2030 in the Council's medium forecast. Between 2009 and 2030, load is expected to increase by a total of 7,000 average megawatts, growing on average by about 335 average megawatts, or 1.4 percent, per year.[1] This forecast has been influenced by expected higher electricity prices that reflect a rapid rise in fuel prices and emerging carbon-emission penalties. For example, residential consumer retail electricity prices are expected to increase by 1.0 percent per year in addition to general inflation. If achieved, cost-effective efficiency improvements identified in the Sixth Power Plan will help to meet a substantial portion of this projected demand growth.

The electricity demand increase is driven primarily by significant growth in two areas: home electronics and elder-care facilities. Demand for home electronics--a new component to the Council's residential sector--is expected to double in the next 20 years. In the commercial sector, the elder-care segment is increasing as the population ages. While the industrial sector is growing at a relatively slow pace, custom data centers (Google, etc.) are a relatively new end-use that has been seeing significant growth as well.

The Northwest has always been a winter-peaking power system. However, due to growing summer load, mostly because of the increased use of air conditioning, the difference between winter- and summer-peak load is expected to shrink over time. Assuming normal weather conditions, winter-peak demand in the Sixth Power Plan is projected to grow from about 34,000 megawatts in 2010 to around 43,000 megawatts by 2030, an average annual growth rate of 1 percent. Summer-peak demand is forecast to grow from 29,000 megawatts in 2010 to 40,000

[1] Demand for electricity, measured at consumer location, is projected to grow by about 6,000 average megawatts, growing on average by about 300 megawatts or 1.4 percent per year.

megawatts by 2030, an annual growth rate of 1.7 percent. By the end of the planning period, the gap between summer-peak load and winter-peak load has narrowed.

The projected growth of demand is comparable to the actual growth rate experienced during the 1990s. When new cost-effective conservation is subtracted, the need for additional generation will be quite small compared to past experience. However, summer supply needs will likely increase as summer-peak demand continues to grow. In addition, the growing share of variable wind generation may change the types of generation needed to meet demand. There is likely to be an increased need for resources that can provide reliable capacity to meet high load conditions and that can operate flexibly to accommodate variable, but non-CO2 emitting, wind energy.

INTRODUCTION

The 2001 energy crisis in the West refocused the region on long-term demand forecasting. There has been a renewed interest and concern about generating capacity and flexibility as well. To deal with these issues, the Council replaced its end-use forecasting models with a new end-use forecasting and policy analysis tool and, working with Bonneville, adapted it to the regional power system and the Council's planning requirements. The new demand forecasting system is based on the Energy 2020 model and generates forecasts for electricity, natural gas, and other fuel.

The Energy 2020 model is an integrated end-use forecasting model. The Council will use the demand module of Energy 2020 to forecast annual energy and peak loads for electricity as well as other fuels. The model has been used extensively by several utilities, and within the region the Bonneville Power Administration uses a version of it.

Three electricity demand forecasts were developed in the Sixth Power Plan. Each scenario corresponds to an underlying set of economic drivers, discussed in Chapter 2 and Appendix B. The high and low ranges of the load forecasts are not explicitly used in the development of the Power Plan, but rather are used as loose guidelines for the regional portfolio model when creating the 750 alternative load forecasts. These demand scenarios reflect an estimate of the impact of the current recession.

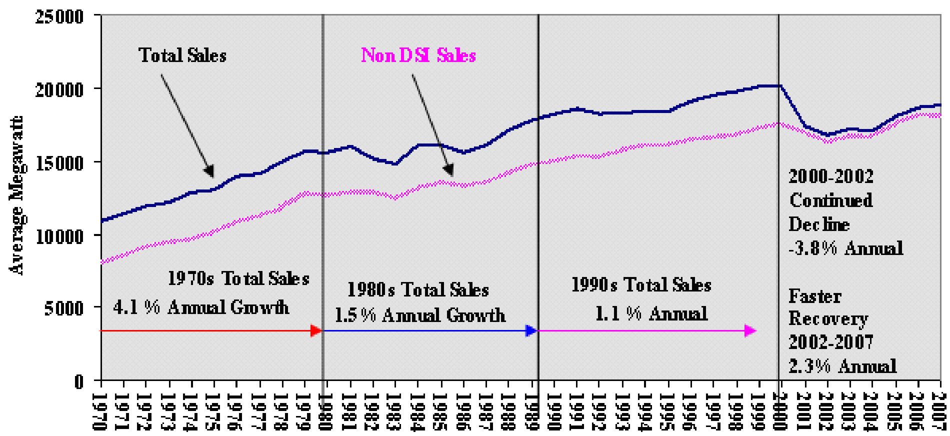
Historic Demand Growth

It has been 26 years since the Council's first Power Plan in 1983. In the decade prior to the Northwest Power Act, regional demand was growing at 4.1 percent per year and the non-direct-service industry (DSI) load was growing at an annual rate of 5.2 percent. Back in 1970, regional demand was about 11,000 average megawatts. In the decade between 1970 and 1980, it grew by about 4,700 average megawatts. During the 1980s, demand growth slowed significantly, falling to about 1.5 percent per year and load increased by about 2,300 average megawatts. In the 1990s, another 2,000 average megawatts were added to regional demand, making growth in the last decade of the 20th century only about 1.1 percent per year. The energy crisis of 2000-2001 increased electricity prices dramatically. As a result, regional demand decreased by 3,700 average megawatts between 2000 and 2001, and eliminated much of the growth since 1980. The bulk of this decline was in the region's aluminum industry and other energy-intensive industries. Since 2002, however, regional demand has begun to recover, growing at an annual rate of 2.5 percent. This growth has been driven by increases in commercial and residential sector demand. Nevertheless, demand remains well below levels of the late 1990s. Table 3-1 and Figure 3-1 illustrate regional electricity demand from 1970-2007.

Table 3-1: Historical Growth Rate of Regional Electricity Sales[2]

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%

Figure 3-1: Total and Non-DSI Regional Electricity Sales (MWa)



The dramatic decrease in demand after the Power Act 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 was the result of a shift in the regional economy as the number of energy-intensive industries declined, largely because of the dramatic increase in electricity prices that followed the region's over-investment in nuclear generation in the 1970s and increased investment in conservation. As shown in Table 3-2, electricity intensity in terms of use per-capita increased between 1980 and 1990, but has been declining since 1990.

Table 3-2: Changing Electricity-Use Intensity of the Regional Economy (Non-DSI Sales Per Capita Adjusted for the weather)

Year	Electricity Use per Capita (MWa / Thousand Person)
1985	1.50
1990	1.57
2000	1.52
2007	1.45

The upswing in demand since 2002 has been mainly due to growth in residential and commercial sector sales. By the end of 2007, the residential sector had added about 888 average megawatts and the commercial sector had added 285 average megawatts, whereas the industrial sector saw a reduction of 337 average megawatts. The industrial sector represented 6,300 average megawatts of demand in 2000, but by 2002 the demand from the industrial sector was reduced to 3,300 average megawatts. The bulk of the drop in demand was due to the closure of aluminum smelting plants, which accounted for nearly 40 percent of industrial electricity use. The demand from this industrial group dropped from 2,543 megawatts in 2000 to about 410 megawatts in 2002. Large users in a few industrial sectors such as pulp and paper, food processing, chemicals, primary metals other than aluminum, and lumber and wood products dominate the remainder of the industrial sector's electricity use. Many of these sectors have declined or are experiencing

[2] 2007 is the last year for reliable data on regional sales. Reliable 2008 data are not available at this time.

slow growth. These traditional, resource-based industries are becoming less important to regional electricity demand, while new industries, such as semiconductor manufacturing, are growing faster.

SIXTH POWER PLAN DEMAND FORECAST

Demand is forecast to grow from about 19,000 average megawatts in 2007 to 25,000 average megawatts by 2030 in the medium-case forecast. The average annual rate of growth in this forecast is about 1.2 percent. This level of growth does not take into account reductions in energy from new conservation resources. To the extent conservation is used to meet demand growth, the forecast will decrease.

Assuming normal weather conditions, the winter-peak load 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 percent. Summer-peak load is projected to grow from 29,000 megawatts in 2010 to 40,000 megawatts by 2030, an annual growth rate of 1.6 percent.

The medium-case forecast means that the region's electricity needs would grow by about 6,000 average megawatts by 2030, absent any conservation, an average annual increase of 267 average megawatts. Most of the growth is from increased electricity use by the residential and commercial sectors, with slower growth in the industrial sector, especially for energy-intensive industries. Higher electricity and natural gas prices have fundamentally shifted the energy intensity of industries in the region. As a result of the 2000-01 energy crisis and the mild recession of 2002, the region lost about 3,500 average 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 2008-09 recession may prolong this recovery.

Demand Forecast Range

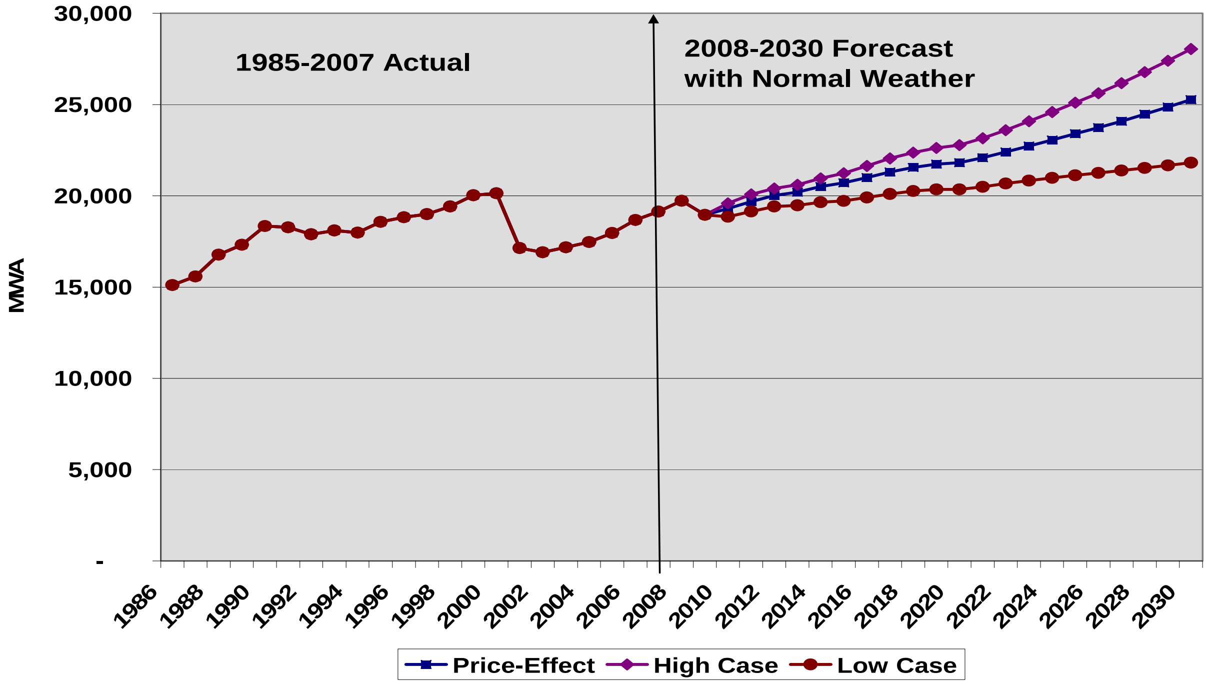
Uncertainty about economic and demographic variables, along with uncertainty about fuel prices, adds to uncertainty about demand. To evaluate the impact of these economic and fuel-price uncertainties in the Sixth Power Plan, two alternative demand forecasts were produced. The Sixth Power Plan's low to high range is based on Global Insight's October 2009 range of national forecasts. To forecast demand under each scenario, the appropriate economic and fuel projections were used. Table 2-1, presented in Chapter 2, shows a range of values for key economic assumptions used for each scenario. The resulting range in the demand forecast is shown in Table 3-3 and Figure 3-2.

Two alternative scenarios were developed for the Sixth Power Plan. The most likely range of demand growth (between the low and high forecasts) is between 0.8 and 1.5 percent per year. The low scenario reflects a prolonged recovery from the recession, and the high scenario reflects a more robust recovery and future growth.

Table 3-3: Sixth Northwest Power Plan Electricity Demand Forecast Range (MWa)[3]

	Actual 2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2020-2030	Growth Rate 2010-2030
Low	19,140	18,860	20,463	22,010	0.8%	0.7%	0.8%
Medium	19,140	19,292	21,820	25,275	1.2%	1.5%	1.4%
High	19,140	19,591	22,651	27,761	1.5%	2.1%	1.8%

Figure 3-2: Historical Sixth Northwest Power Plan Sales Forecast (MWa)



Sectoral Demand

The Sixth Power Plan forecasts demand to grow at an average annual rate of 1.4 percent in the 2010 through 2030 period. The residential sector is expected to grow at 1.4 percent per year, which, on average, translates to about 125 megawatts each year. Increased growth in the residential sector reflects a substantial increase in demand for home electronics, categorized as information, communication, and entertainment (ICE) and the increased use of air conditioning.

Table 3-4 shows the actual 2007 demand for electricity and the forecast for selected years, as well as the corresponding annual growth rates. These demand forecasts do not include any new conservation initiatives.

[3] Sales figures are electricity use by consumers and exclude transmission and distribution losses.

Table 3-4: Medium-Case Sector Forecast of Annual Energy Demand (MWa)

	Actual 2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2020-2030	Growth Rate 2010-2030
Residential	7,424	7,499	8,335	9,987	1.06%	1.82%	1.44%
Commercial	6,129	6,705	8,214	9,170	2.05%	1.11%	1.58%
Industrial Non-DSI	3,904	3,724	3,715	4,360	-0.03%	1.62%	0.79%
DSI*	764	693	772	772	1.09%	0.00%	0.54%
Irrigation	848	599	696	873	1.52%	2.29%	1.90%
Transportation	71	72	87	113	1.91%	2.62%	2.27%
Total	19,140	19,292	21,820	25,275	1.24%	1.48%	1.36%

* Long-term DSI forecast developed by RPM, projects a lower DSI load than the values reflected here.

Commercial sector electricity consumption is forecast to grow by 1.6 percent per year between 2010 and 2030. During this period, commercial sector demand is expected to increase from 6,700 average megawatts to 9,200 average megawatts. This increase is higher than the 1.2 percent per year that was forecast in the Fifth Power Plan (May 2005). The Sixth Power Plan cases have been adjusted upward to reflect the fact that there has been a tendency to under-forecast commercial demand. The forecast for 2025 is about 1,700 average megawatts higher than the 2025 medium forecast in the Fifth Power Plan. On average, this sector adds about 110 average megawatts per year.

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

Industrial (non-direct-service industries) 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 4,400 in 2030. 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 about 300 average megawatts of connected load for these businesses. Demand from this sector is forecast to increase by about 7 percent per year. However, considering existing opportunities to improve the energy efficiency of custom data centers, it was assumed that demand from these centers will grow about 3 percent per year.

In the Sixth Power Plan, DSI consumption was assumed to 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.

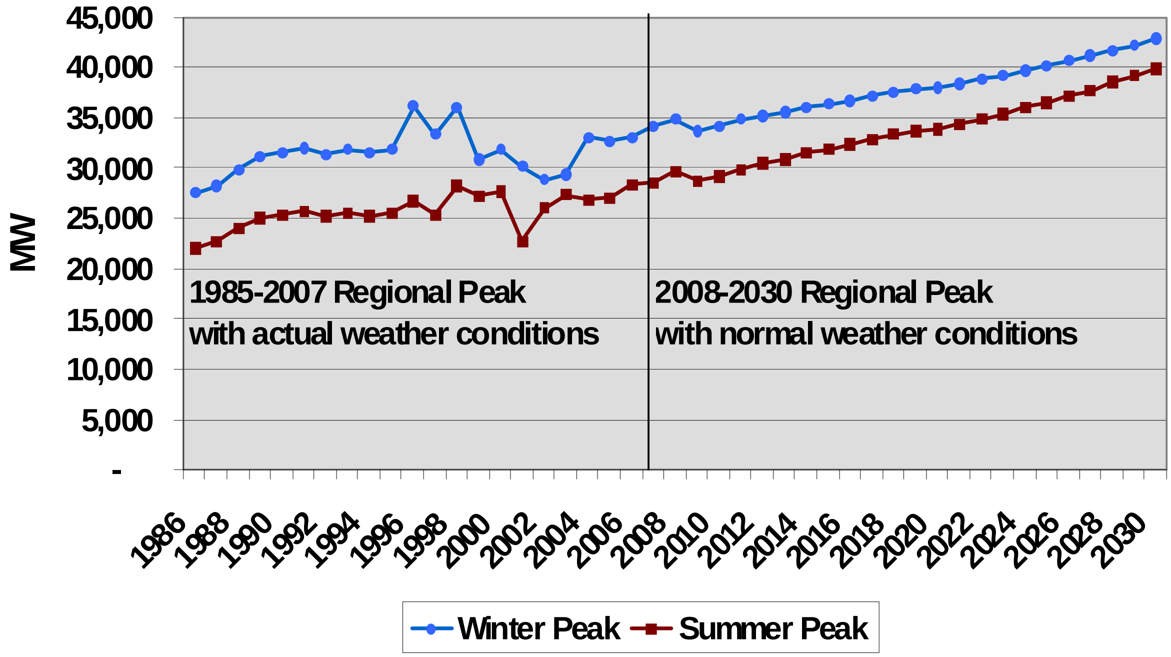
LOAD FORECAST AND PEAK LOAD

Peak Load

The Council's new long-term demand forecasting system forecasts annual sales, as well as monthly energy and peak load. The Council often refers to electricity sales to consumers as demand, following the Northwest Power Act's definition. The difference between sales and load is transmission and distribution losses on power lines. Regional peak load is determined from the end-use level for each sector. The regional peak load for power, which has typically occurred in winter, 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. Assuming normal historical 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.

The forecast for regional peak load assumes normal weather conditions. There are no assumptions regarding temperature changes incorporated in the Sixth Power Plan's load forecast at this time. Sensitivities will be conducted to help assess the potential effects of climate change on electricity use (See Appendix L). Figure 3-3 shows estimated actual peak load for 1985-2007, as well as the forecasts for 2008-2030. Note that load growth looks very steep due to the graph's smaller scale.

Figure 3-3: Historical and Forecast Regional Peak Load (MW)



Load Forecast Range

Figure 3-5 shows forecast winter and summer peak load under the three alternative cases. Assuming the high-growth scenario, regional summer-peak load is expected to grow from about 28,000 megawatts in 2007 to about 43,000 megawatts by 2030. Between 2010 and 2030, the growth rate in summer-peak load is 1.9 percent per year. The growth rate of winter-peak load in the high case is lower than the growth in average annual energy demand. Assuming normal weather, the region is forecast to remain a winter-peaking system. However, the difference between winter and summer peak loads shrinks over time.

Table 3-5: Total Summer and Winter Peak Load Forecast Range (MW)

	Actual 2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2020-2030	Growth Rate 2010-2030
Low - Winter	33,908	33,572	35,412	36,949	0.5%	0.4%	0.5%
Low - Summer	28,084	28,517	32,027	35,559	1.2%	1.1%	1.1%
Medium - Winter	33,908	34,184	37,977	42,814	1.1%	1.2%	1.1%
Medium - Summer	28,084	29,211	33,800	39,865	1.5%	1.7%	1.6%
High - Winter	33,908	34,611	39,397	46,788	1.3%	1.7%	1.5%
High - Summer	28,084	29,706	34,923	43,360	1.6%	2.2%	1.9%

In the low case, summer-peak load is expected to grow from 28,000 megawatts in 2007 to 35,000 megawatts in 2030. Winter-peak load grows from 34,000 in 2007 to 37,000 in 2030. Other patterns between summer and winter peaks are similar to the other cases. Winter peaks grow more slowly than average energy load, and summer peaks grow faster.

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" 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 forecast reflects customers' choices in response to electricity and fuel prices and technology costs, without any new conservation initiatives. This forecast does not include 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 two other long-term forecasts that are required for estimating conservation potential and running the resource portfolio model.

1. **Frozen-efficiency forecast**. A "frozen-efficiency" forecast is when load is calculated based on fixed or frozen efficiency levels as of the base year of the plan. This forecast attempts to eliminate the double-counting of conservation savings. The frozen technical-efficiency levels form the conservation supply model's starting point. In the frozen-efficiency forecast, the fuel efficiency choice is held constant at the base-year level and not changed over time, except where there is a known increase due to codes or standards.
2. **Sales forecast**. A "sales"[4] 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 regional portfolio model. The sales forecast captures both price effects and take-back effects (due to increased usage as efficiency of usage increases).

The difference between the price-effect and frozen-efficiency load forecasts is relatively small. The frozen-efficiency forecast typically is higher than the price-effect forecast; in the Sixth Power Plan the two forecasts differ by about 400 average megawatts by 2030. Figures 3-4 through 3-6 show these three forecasts for energy and for summer and winter capacity in the

[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, and load is measured at the generator site.

Sixth Power Plan. Conservation resource program savings incorporated[5] in the sales forecast reduce 2030 average annual load by about 5,900 megawatts and reduces summer peak load by about 6,000 megawatts, or roughly by 15 percent. Winter peak loads are reduced by about 11,000 megawatts or about 24 percent.

Figure 3-4: Average Annual Load Forecasts (MWa)

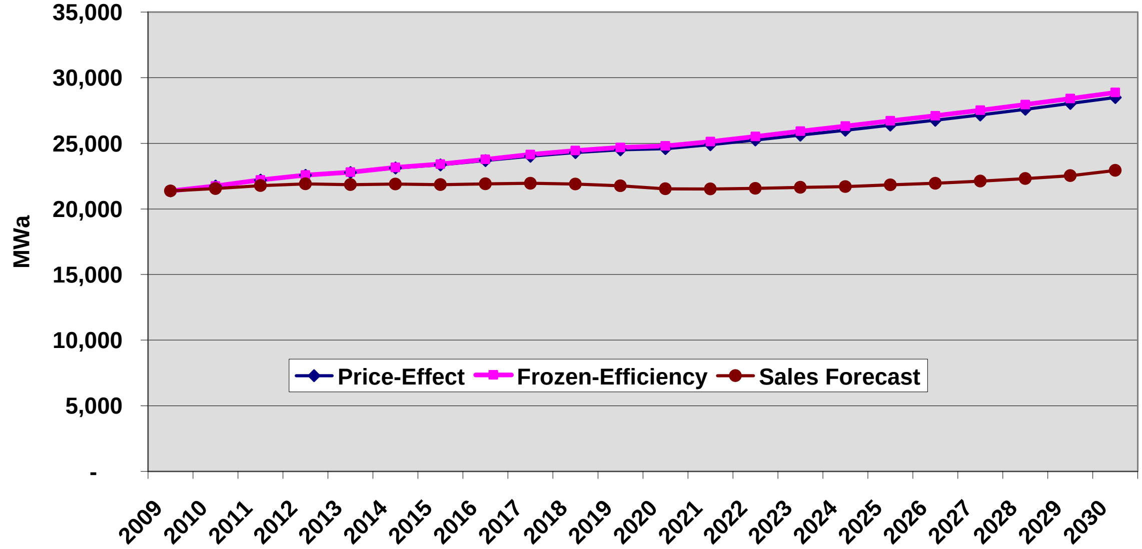
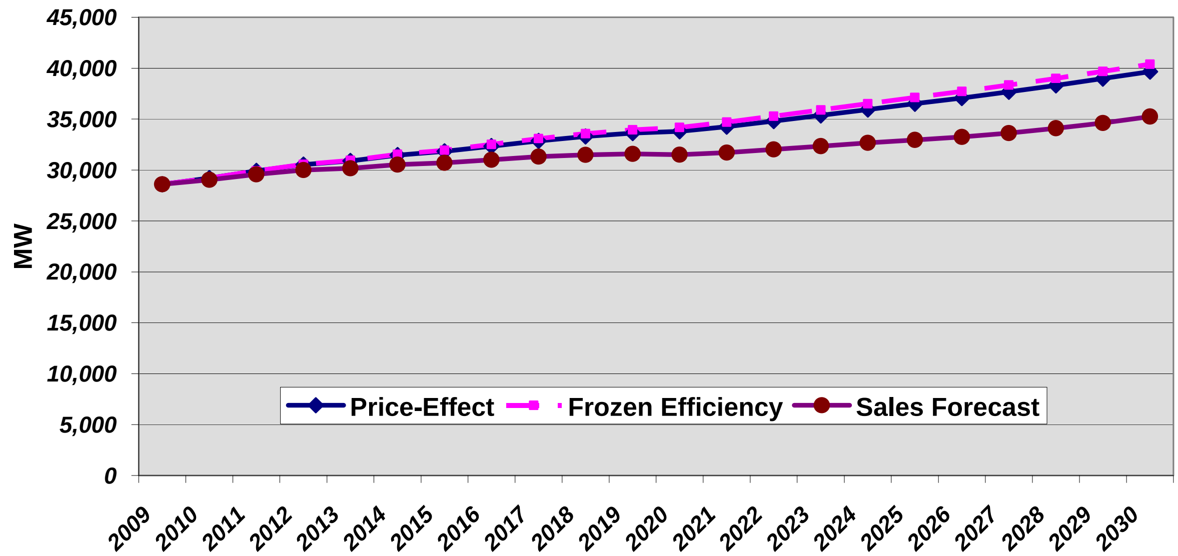
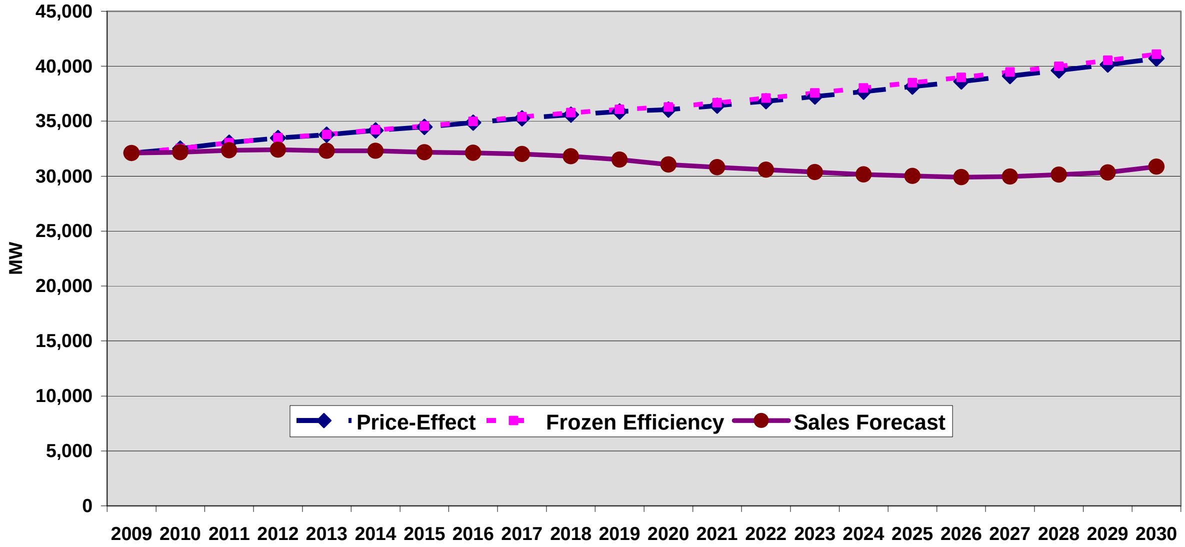


Figure 3-5: July Peak Load Forecasts (MW)



5 Anticipated annual impacts of conservation programs, by sector and end-use, are netted out of the frozen-efficiency loads for that year, sector, and end-use.

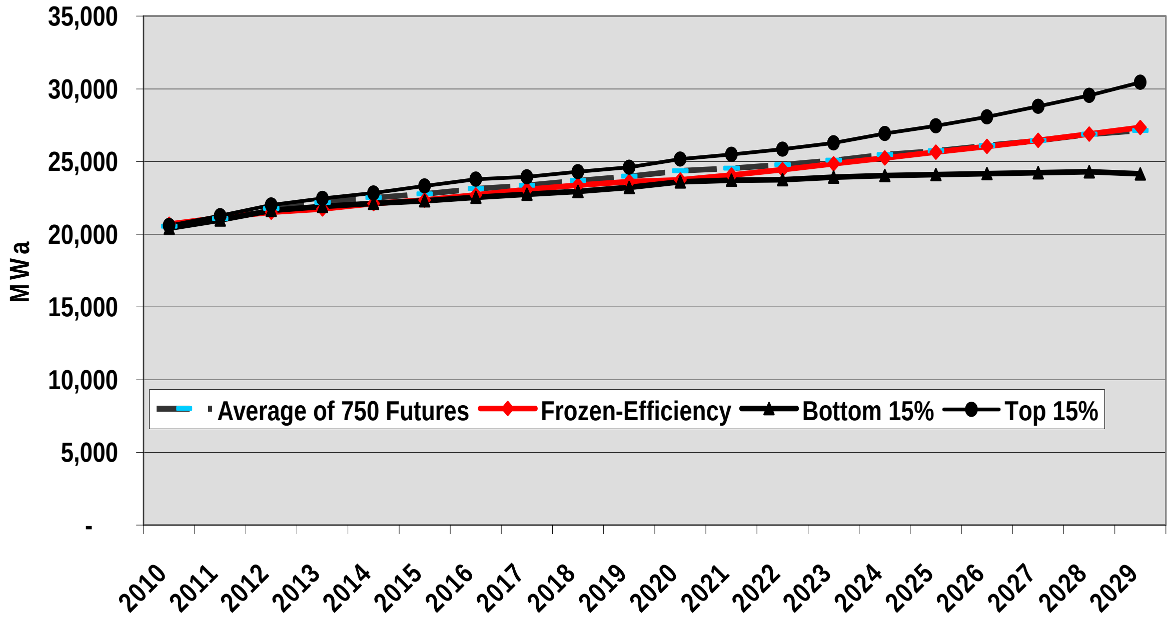
Figure 3-6: January Peak Load Forecasts (MW)



Portfolio Model Analysis of Non-DSI Load

While the Council uses three types of long-term load forecasts, the monthly frozen-efficiency load forecast is the primary forecast used in the regional portfolio model (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. In any given period, the RPM may deviate from the long-term load forecast; however, on average the loads created by the RPM are very close to the frozen-efficiency load forecasts. The following table shows a comparison between the frozen-efficiency load forecast and the RPM-generated loads. The graph shows a representative range of load forecasts developed. The RPM generates 750 different future load-growth paths; to graphically represent all these futures would not possible. Here, the averages of the highest 15 percent and lowest 15 percent of the 750 load paths, as well as the average of all the 750 growth paths, are compared with the frozen-efficiency forecast. It should be noted the loads presented in this graph are for non-DSI loads. A more robust discussion of the RPM is presented in Chapter 9 and Appendix J.

Figure 3-7: Load Forecasts (MWa)



Impact on Revenue Requirement

What is the impact of the plan's resource recommendations on customers' electricity costs and how do predicted costs compare to historic trends?

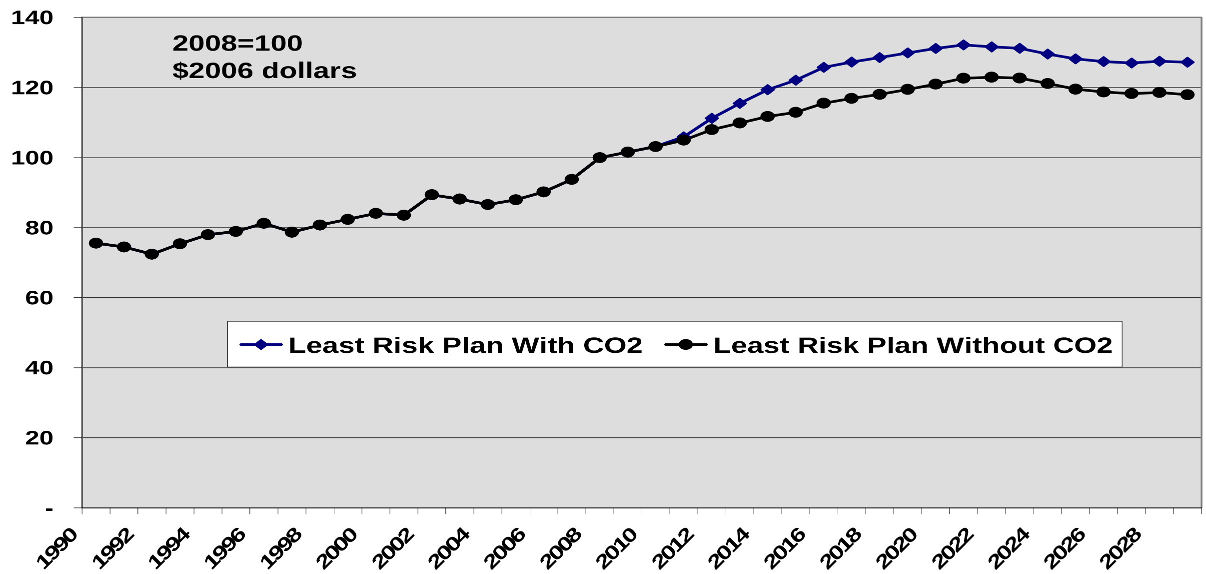
Customers' bills are expected to decrease by 0.2 percent to 0.7 percent per year depending on treatment of CO2 costs. If the CO2 penalty is not included in the revenue requirement, customers' electricity bills are expected to decline at an average annual rate of 0.7 percent. If CO2 costs are included, customers' electricity bills are expected to decline at an average annual rate of 0.2 percent. It should be noted that over time residential customer bills and the revenue requirement change at different rates, due to an increasing number of households. The average revenue requirement grows at an average annual rate of 0.5 percent,[6] and the number of households grows at a rate of 1.2 percent, resulting in bills decreasing at 0.7 percent per year.

To compare the future trend in costs with the historic trend, we need to create comparable numbers by removing the effects of inflation. The dollars of revenue collected by electric utilities for each year between 1990 and 2008 were converted to 2006 dollars. The future projected revenue requirement under the carbon risk scenario was compared to historic levels. The historic and future revenue requirement was indexed to 2008 by setting 2008 revenues to 100. Analysis shows that during the 1990-to-2008 period the revenue requirement increased at an average annual rate of 1.6 percent. In the 2010-to-2030 period, under the carbon-risk scenario, the revenue collected from customers is projected to increase at an average annual rate of 0.5 percent to 1.0 percent per year, depending on the incidence of the CO2 tax. More detail

[6] The calculation of future revenue requirements includes an assumption that current fixed costs of resources, transmission, and distribution systems remain fixed in real dollars. Implicit in this assumption is that the cost of new transmission and distribution infrastructure expansion is offset by the depreciation of existing infrastructure assets. Eastern Montana wind, however, is assumed to require additional transmission investment and that cost is explicitly added to the cost of the Montana wind resource.

regarding the impact of the plan on average revenue and customer bills can be found in Appendix O.

Figure 3-8: Indexed Revenue Requirement



Demand From Plug-in Hybrid Electric Vehicles (PHEV)

Over 70 percent of automakers[7] are introducing plug-in hybrid electric vehicles (PHEV). Between 2010 and 2030 we estimate that more than13 million new passenger and light vehicles will be purchased in the Northwest, of which 600,000 to 3.5 million could be PHEV.

To better understand the potential impact of PHEV on the system load, a limited "what-if" sensitivity study was conducted.[8] The Council assumed a range of penetration of these cars into the market, with the result that regional electricity use increases by between 100 and 550 average megawatts.

The estimated effects on electricity bills and rates were small. The impact on rates to a large extent depends on when the PHEV is recharged. In the Council's analysis, it was assumed that 95 percent of PHEV recharge would occur at night or on weekends, during system off-peak hours. To encourage and ensure off-peak recharge would require regulatory and technological changes. Technological change in the form of smart grid and uniform recharge protocols would enable the owners of PHEV to know the optimum recharge period. Regulatory rates would need to provide incentives for off-peak charging.

The forecast of new light vehicles in the four Northwest states indicates that between 2010 and 2030 about 13 million new vehicles will come on to the roads. Some of these vehicles would replace existing vehicles and some would meet new transportation requirements of a growing population. The PHEV share of this market would depend on a number of factors such as gasoline prices, tax on CO2 emissions, and the price and reliability of PHEV. In the sensitivity analysis, it was assumed that all these factors translate into a market share factor. Three

[7] By market-share, from E-source presentation on "Building the plug-in Vehicle Infustructure" Nov 2009.
[8] This sensitivity study was not included in the base case (price effect) analysis for the plan.

different long-term market-share factors were assumed. Case 1 assumes 10-percent market share, while cases 2 and 3 assume 28 percent and 40 percent, respectively.

The following figures show the year-by-year market-share assumptions as well as annual and off-peak energy requirements for PHEV. It was assumed that market acceptance of PHEV will be small in the first five years of their introduction. By the 15th year, the assumption is that market acceptance will level off at 10-40 percent. Figure 3-9 shows the assumed annual new-vehicle market-penetration rates for PHEV. We also have assumed that the efficiency of the PHEV and conventional fossil-fuel vehicles would improve over time. Figures 3-10 and 3-11 show the annual demand for electricity for PHEV. PHEV are expected to add between 100-550 average megawatts to regional load and about twice as much to the off-peak demand. A detailed discussion of PHEV analysis is presented in Appendix C of the power plan.

Figure 3-9: Assumed New Car Market Share for PHEV

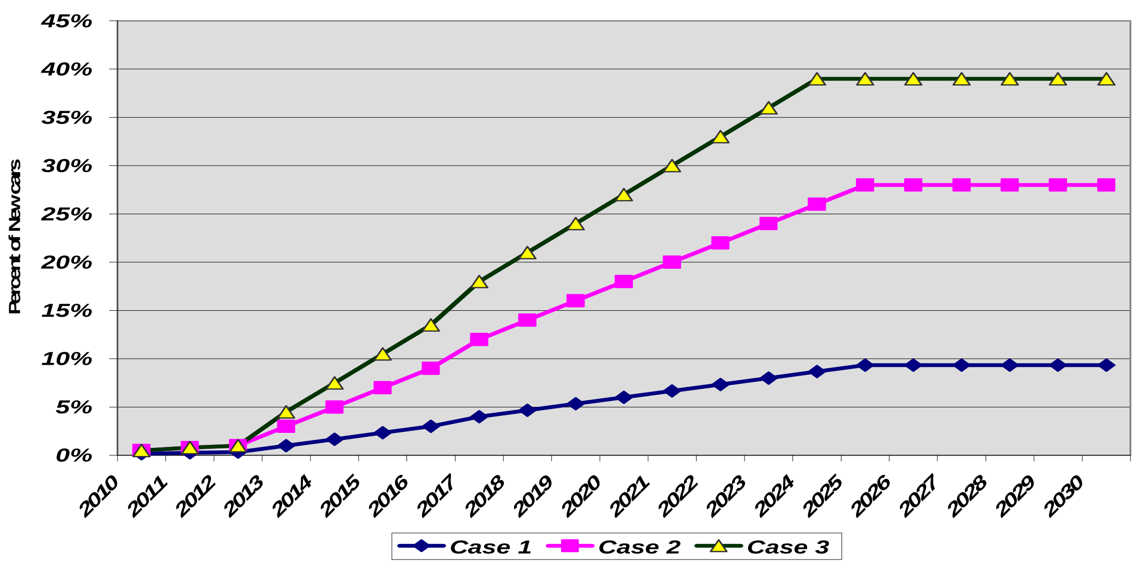


Figure 3-10: Projected Load from Plug-in Hybrid Vehicles

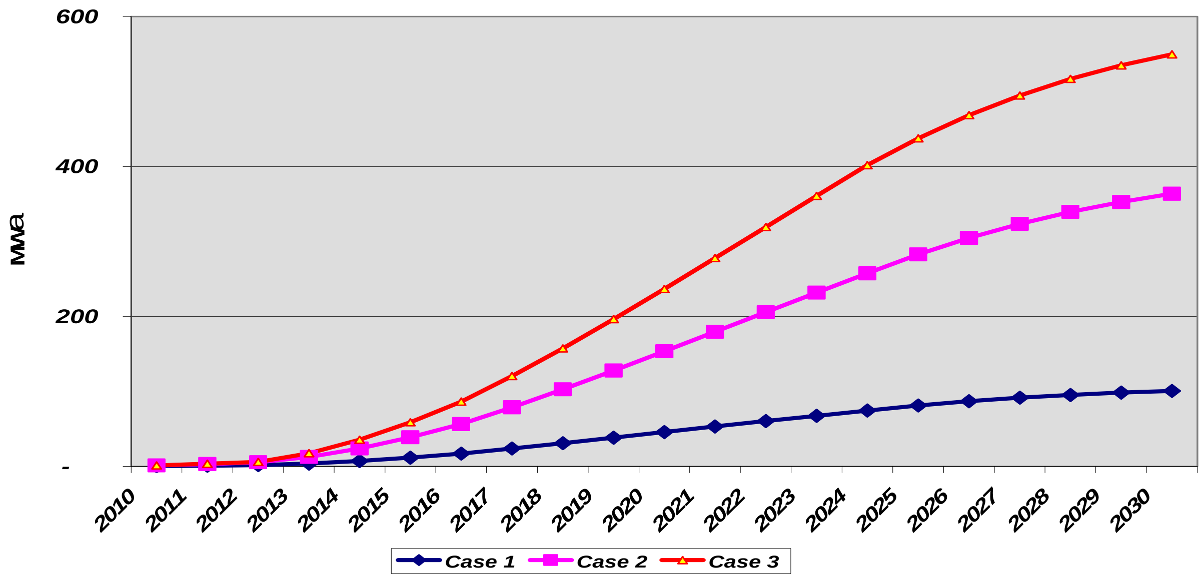
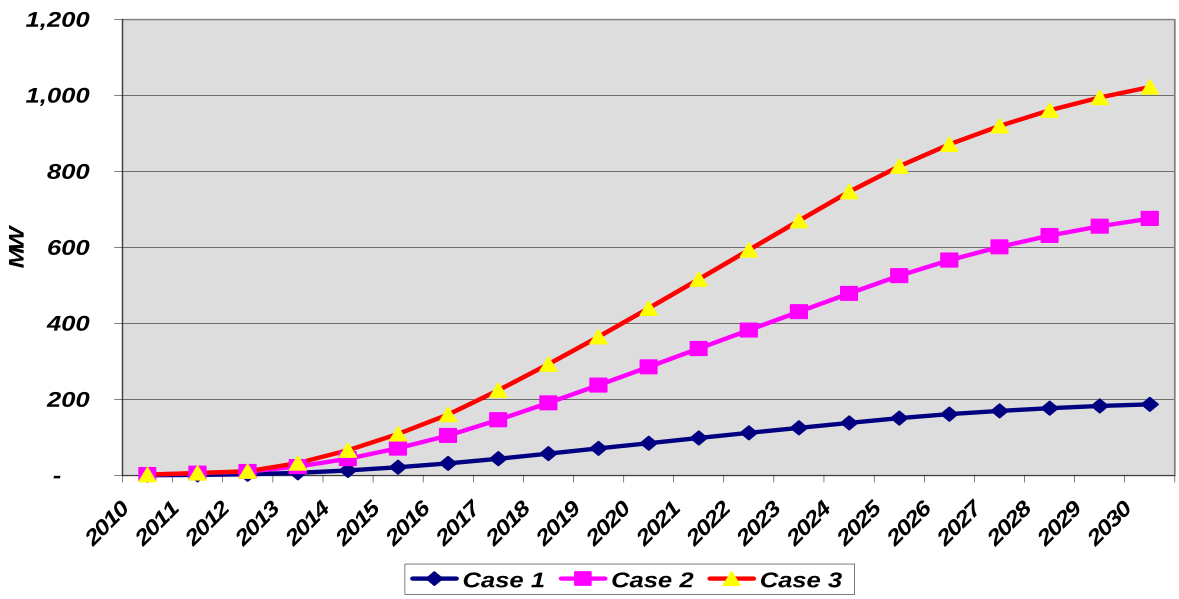


Figure 3-11: Project Off-peak Load from Plug-in Hybrid Vehicles



Opportunities and Challenges

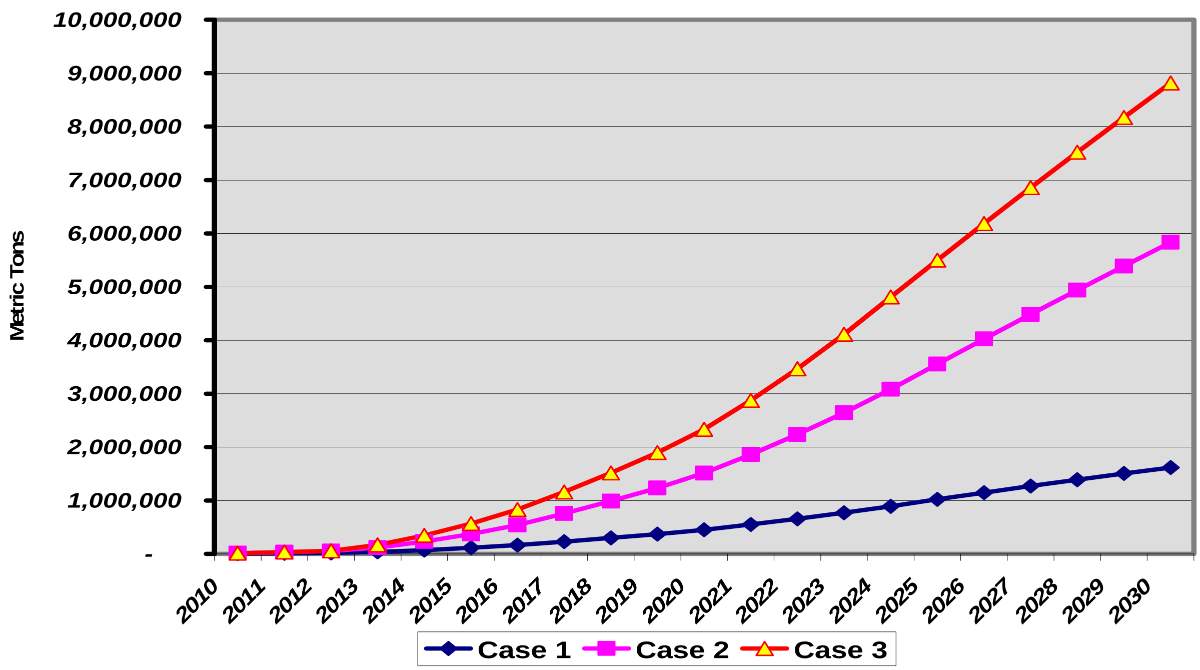
The projected levels of PHEV penetration represent both opportunities and challenges for the power system in the Northwest. If fully subscribed, by 2030, the PHEV fleet potentially could store the equivalent of between 2 and 10 percent of the energy and between 3 and 20 percent of the eight-hour sustained peaking capacity of the hydropower system in the Northwest.

However, integration of potentially millions of PHEVs into the power grid will require building an intelligent bi-directional telecommunication infustructure that would optimize recharge schedules based on consumers' driving habits and power utilities' needs. What is needed is an integration of three sectors- transportation, information, and electric power. To make possible the communication between local utilities, millions of dispersed vehicles, and thousands of recharge stations, common national communication standards along with local utilities' incentivized rates and a seamless recharge infrastructure are necessary. The utilities will need to provide incentives to PHEV drivers to subscribe to smart charging programs, where the utility could manage the timing and pace of the recharge.

Environmental Impacts

The impact of PHEV on the emissions from electricity generation depends on the timing of recharge and future mix of generation. In the regional portfolio model, by 2030 the difference in CO2 emissions from the power system was 0.8 million metric tons higher[9] due to PHEV loads. But the increase in CO2 emissions from power plants is more than offset by the decrease in emissions by vehicles. The US Department of Energy estimates that in the four states of Oregon, Washington, Idaho, and Montana, tail-pipe emissions in 2007 were about 90 million metric tons. The Council's estimates show that, depending on market acceptance of PHEV and response from conventional-fuel vehicles,[10] by 2030 tail-pipe emissions could be lower by 2 to 9 million metric tons.

Figure 3-12: Potential Reduction in Tail-pipe CO2 due to Plug-in Hybrid Vehicles



Meeting the energy requirement of PHEV may not require new resources.. Council analysis shows that if the plan's conservation targets are met, by 2030 the off-peak demand for energy could be reduced by about 3,800 megawatts. This amount of off-peak demand reduction would be sufficient to power an all-PHEV new vehicles fleet in the region.

[9] 37.8 million metric tons compared to 37 million in the least-risk scenario.
[10] This assumes that as a result of national standards, higher fuel prices and availability of PHEV, conventional fuel vehicles would improve their fuel efficiency from 21.7 miles per gallon in 2010 to 35 miles per gallon by 2030.

ASSESSMENT OF NEEDS - UTILITY PERSPECTIVE

Regional utilities have consistently used the annual average load/resource balance as a quick and simple metric to get an indication of their resource needs. For the region, the load/resource balance reported in PNUCC's Northwest Regional Forecast (NRF) provides an aggregate look at utility-resource needs. That calculation assumes firm loads and resources,[11] which include critical-water hydropower generation but no market resources. A general conclusion that can be made from this metric is that when the average annual load is greater than the firm supply, additional resources likely are needed.

However, this utility-perspective metric is very limited and requires assessment. The Council and utilities must use more sophisticated analyses, which take other uncertainties into account, in order to develop a more comprehensive needs assessment and, more importantly, a robust resource-acquisition strategy (more commonly referred to as an integrated resource plan). The Council's methodologies for assessing the region's needs and for developing a resource strategy are described in Chapter 9 (Developing a Resource Strategy) and in Chapter 10 (Recommended Resource Strategy), respectively.

The Council's assessment of power supply adequacy, developed by the Resource Adequacy Forum, uses a more sophisticated methodology than simply comparing firm loads and resources. Adopted by the Council in 2008, it uses probabilistic tools to assess the likelihood of potential problems given firm, non-firm, and market resources. A more detailed description and a summary of results are provided in Chapter 14 (Resource Adequacy Standards).

Yet, in spite of the limitations of the simple firm-load/resource-balance metric for assessing resource needs, this perspective is beneficial in that it is readily available to all utilities and provides a starting point for further discussion. Also, by reconfiguring Council assessments to fit this perspective, results can be compared with other utility-published reports. The following section illustrates the Council's assumptions for loads and resources portrayed in a utility perspective.

Annual Needs

As a starting point for assessing regional resource needs based on a utility perspective, it is necessary to identify long-term load uncertainty and existing firm-resource capability. Existing resources include those that are owned or operated by regional utilities to serve regional loads, regardless of their physical location. The generating capability of existing resources is adjusted for maintenance and for the likelihood of forced outages. It is also adjusted to reflect utility operating assumptions. For example, a utility may own a 100-megawatt capacity simple-cycle combustion turbine, which it intends to use for hourly peaking needs only. Because of the way in which the utility expects to operate this resource, it may only use 5 percent (or 5 average megawatts) to count toward the annual average firm-resource generating capability. The existing resource capability shown in the following charts has been adjusted for this effect.

The range of uncertainty in long-term loads (through the year 2030), was derived from the regional portfolio model, which takes into account a wide variation in potential future economic growth. The high end of the load uncertainty range represents the average load for

[11] Firm loads are net of firm exports and imports. Firm resources consist of firm non-hydropower and critical-water hydropower resources.

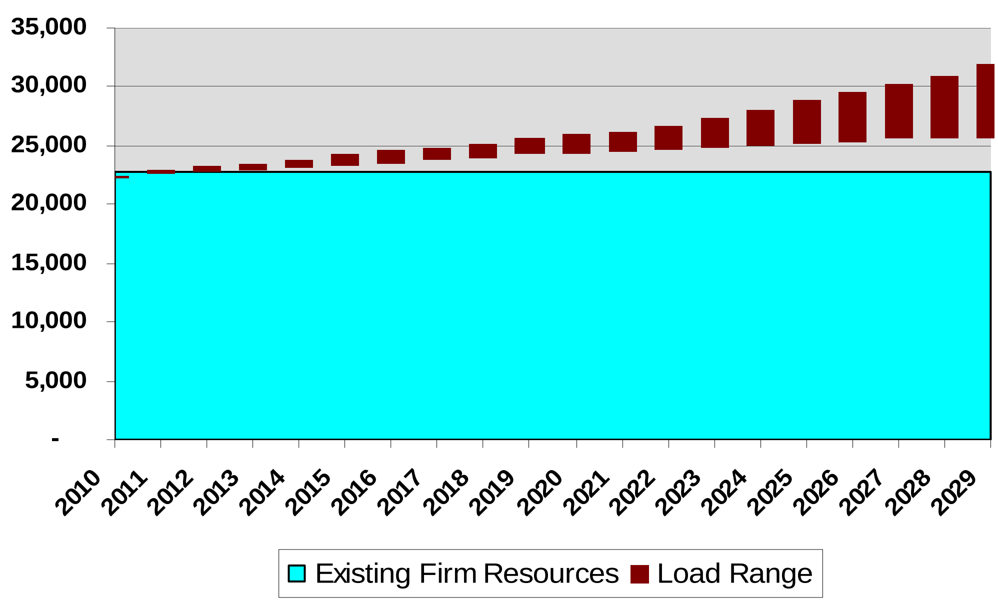
approximately the highest 15 percent[12] of the load paths from the model. The low end of the range represents the average load for approximately the lowest 15 percent of the load paths from the model. This load range includes the net effect of firm contractual imports and exports.

The following graphs compare existing firm-resource generating capability (as defined above) with the high and low range for future loads. The floating blocks in Figure 3-13 represent the range of uncertainty in load growth through the end of the study horizon. In 2029, for example, annual regional firm load can range from a low of about 23,000 average megawatts to a high of about 31,000 average megawatts.

Based on a utility perspective, as depicted in Figure 3-13, existing firm resource capability is only sufficient to satisfy regional needs through 2012. However, this does not mean that our power supply is inadequate. What it does mean is that counting only firm resources (in a way defined by utilities) and critical hydropower generation, the power supply cannot serve the anticipated firm load. This gap can be filled in a number of ways. Utilities could choose to build or acquire additional firm resources, purchase from the electricity market, operate their existing resources at levels above their planning dispatch levels, or any combination of the three. The optimum strategy must be derived from a comprehensive integrated resource-planning process, which takes many other factors into account.

The data presented in Figure 3-13 is consistent with information provided in PNUCC's NRF. Unfortunately, it provides a relatively narrow view of potential regional needs because it excludes independent power-producer resources and potential access to resources outside the region. In addition, it offers little guidance in terms of developing a cost-effective resource-acquisition strategy. It does, however, indicate that a potential need for new resources exists and that further analysis is required.

Figure 3-13: Utility-Perspective Energy Needs Assessment (MWa)



[12] More precisely, the high end range of load uncertainty for each year is the average of the yearly loads for the top 100 simulations (out of 750 total) sorted by load in the last year of the study (2030).

Hourly Needs

Although not used as often in the past, capacity load/resource balances are becoming more important for assessing the need for new resources. The combination of rapidly growing summer loads and decreasing summer hydroelectric capability is pushing the region to consider more carefully its peaking needs in summer months. Traditionally, capacity load/resource balances have been measured as surplus reserve margins, in units of percent. To calculate a capacity reserve margin, surplus firm-generating capability for the peak-load hour of the day is divided by the load during that hour. This surplus capacity must be sufficient to cover operating- and planning-reserve requirements, fluctuations in load due to temperature, and the potential loss of a generating resource. In regions that are dominated by thermal resources, the desired reserve margin typically is in the range of 15 to 17 percent.

The Northwest, however, is a hydroelectric-dominated system that has limited storage capability. The aggregate storage capacity of all reservoirs is only about 30 percent of the annual average runoff volume in the Columbia River. Because of this storage limitation and other factors, the Northwest power system cannot sustain its single-hour generating capability over long periods. A more appropriate measure of hourly capability is the generation that the system can sustain over a three-day period, which approximates the duration for cold snaps or heat waves in the Northwest. This sustained-peak capability then can be compared to the sustained-peak load. However, to date, no standard has been established for a utility-perspective (firm only) sustained-peak reserve-margin requirement.[13]

Using the same methodology as for the energy-needs assessment above, the utility-perspective January and July sustained-peak capacity needs assessments are illustrated in Figures 3-14 and 3-15. These results cannot be compared directly to PNUCC's Northwest Regional Forecast because it currently does not report capacity data. For January, existing firm resources fall below the high end of the sustained-peak load range by the year 2028; for July, resources fall short of the high end of the load range by the year 2026. However, the loads shown in these figures do not include any reserve-margin requirements. Adding those requirements to the load range will result in an earlier need for resource acquisition. But, as discussed above, utility-perspective, sustained-peak reserve requirements are not clear.

Figure 3-14: Utility-Perspective January Capacity Needs Assessment (MW)

[13] The Resource Adequacy Forum has developed minimum sustained-peak reserve-margin thresholds using a loss-of-load probability analysis (as defined in the Council-adopted adequacy standard). But these thresholds were developed under the assumption that some non-firm resources would be available for dispatch during emergency periods. Because of that, the Forum's thresholds cannot be compared to reserve margins calculated using firm resources only.

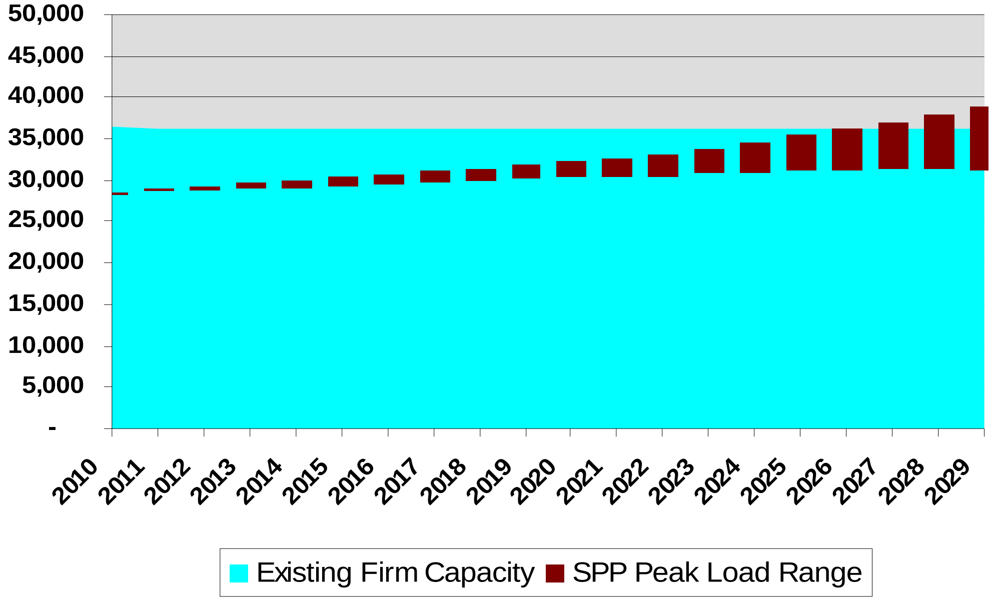
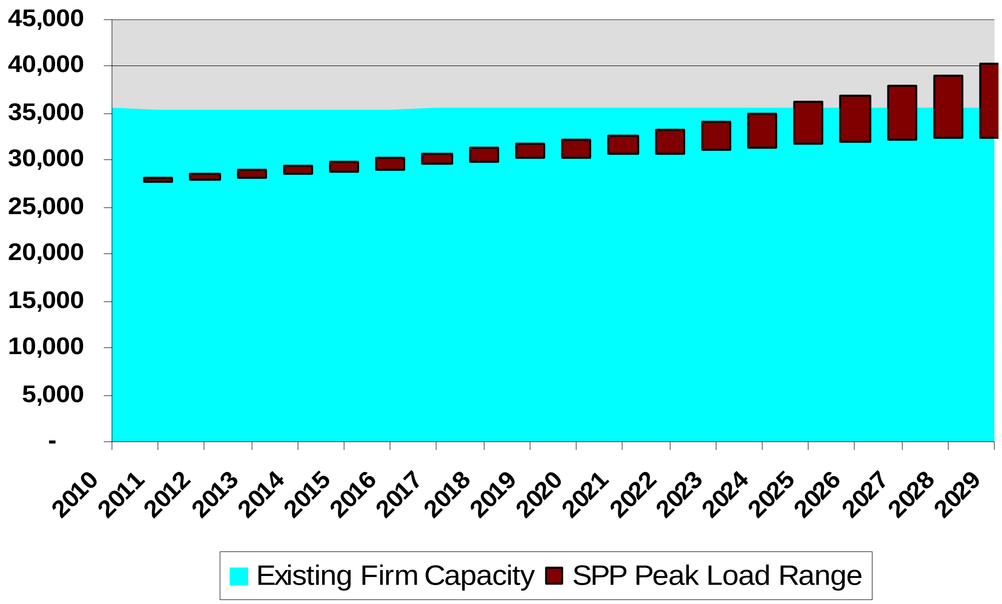


Figure 3-15: Utility Perspective July Capacity Needs Assessment (MW)



An alternative way to display the utility-perspective hourly needs assessment is to graph the sustained-peak reserve margins calculated from data shown in Figures 3-14 and 3-15. Figures 3-16 and 3-17 show the resulting sustained-peak reserve margin ranges for January and July, respectively, using existing firm resources only. If the minimum required reserve margins for January and July were known, these figures would indicate the years in which new resources would be needed. Using 17 percent[14] as a surrogate for the utility-perspective sustained-peak reserve-margin threshold, the need for new resources occurs in 2016 for January and in 2015 for July (when the reserve margins drop below 17 percent). However, these results do not provide an accurate assessment of hourly needs.

[14] California utilities historically have used a 15-to-17-percent reserve-margin requirement for long-term resource planning. However, that requirement is only appropriate for a thermal-based power system, which focuses on single-hour needs as opposed to sustained-peak needs.

Figure 3-16: Utility-Perspective January Reserve Margins (%)

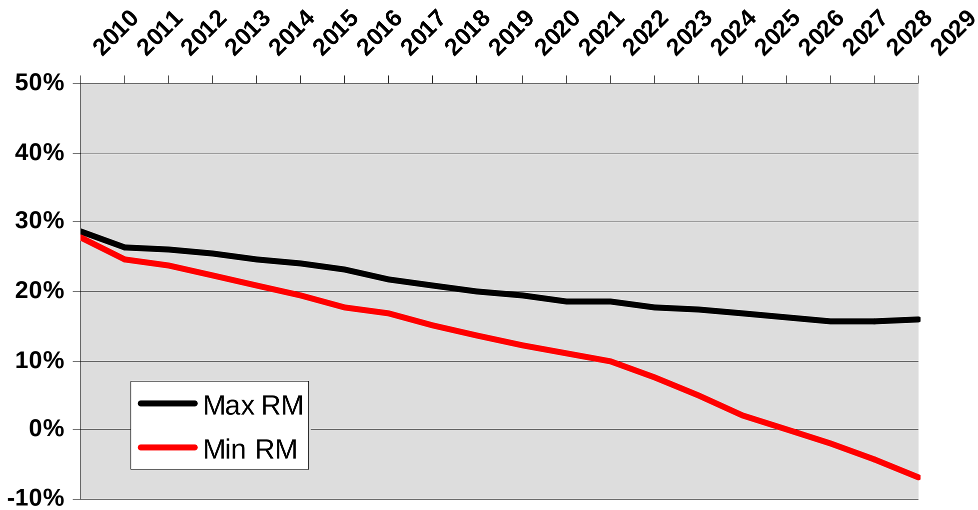
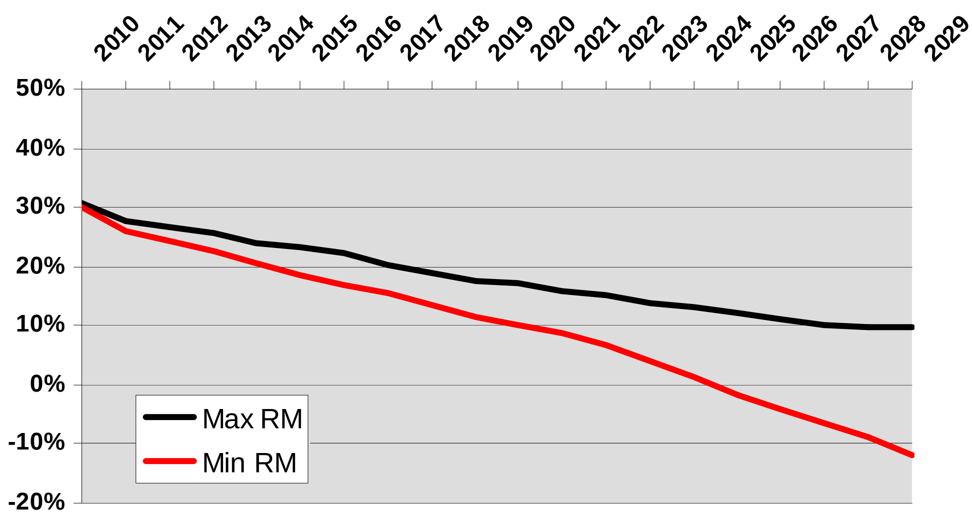


Figure 3-17: Utility Perspective July Reserve Margins (%)



ANNUAL LOAD FORECAST TABLES

Table 3-5: Annual Load under Various Scenarios (MWa)

	Low Case	Price-Effect (Medium Case)	High Case	Sales Forecast (Loads Net of Conservation)
1986		18,272		
1987		18,751		
1988		19,842		
1989		20,681		
1990		20,922		
1991		21,258		
1992		20,807		
1993		21,097		
1994		20,875		
1995		21,140		
1996		21,836		
1997		21,591		
1998		21,902		
1999		22,382		
2000		22,443		
2001		19,321		
2002		19,835		
2003		20,010		
2004		20,204		
2005		20,582		
2006		21,054		
2007		21,575		
2008		22,239		
2009	21,367	21,369	21,371	21,369
2010	21,258	21,745	22,081	21,557
2011	21,580	22,194	22,626	21,800
2012	21,903	22,566	22,982	21,950
2013	21,985	22,774	23,188	21,919
2014	22,181	23,116	23,574	22,009
2015	22,286	23,346	23,875	21,978
2016	22,508	23,675	24,299	22,036
2017	22,745	24,015	24,743	22,084
2018	22,933	24,292	25,091	22,032
2019	23,053	24,499	25,364	21,900
2020	23,063	24,593	25,530	21,652
2021	23,232	24,890	25,932	21,610
2022	23,433	25,246	26,422	21,631
2023	23,631	25,618	26,963	21,673
2024	23,802	25,990	27,512	21,708
2025	23,977	26,374	28,080	21,755
2026	24,135	26,753	28,650	21,803
2027	24,288	27,153	29,255	21,948
2028	24,458	27,582	29,915	22,172
2029	24,627	28,028	30,593	22,422
2030	24,806	28,488	31,291	22,815
2010-2030	0.77%	1.36%	1.76%	0.28%%

Table 3-6: Regional Winter and Summer Peak Load Forecast Range (MW)

	Regional Winter Peak (MW)				Regional Summer Peak (MW)			
	Low Case	Price-effect	High Case	Sales Forecast (Net of Conservation)	Low Case	Price-effect	High Case	Sales Forecast (Net of Conservation)
1986		27,515				22,069		
1987		28,241				22,651		
1988		29,885				23,970		
1989		31,150				24,985		
1990		31,515				25,277		
1991		32,021				25,683		
1992		31,340				25,137		
1993		31,775				25,486		
1994		31,440				25,217		
1995		31,840				25,538		
1996		36,118				26,644		
1997		33,292				25,287		
1998		35,971				28,198		
1999		30,753				27,156		
2000		31,910				27,636		
2001		30,215				22,697		
2002		28,883				26,002		
2003		29,395				27,391		
2004		32,936				26,752		
2005		32,654				26,961		
2006		32,951				28,275		
2007		33,908				28,084		
2008		34,811				29,702		
2009	33,700	33,704	33,707	33,704	28,591	28,591	28,592	28,591
2010	33,572	34,184	34,611	33,823	28,517	29,211	29,706	29,039
2011	33,948	34,774	35,347	34,029	29,074	29,912	30,513	29,548
2012	34,280	35,248	35,841	34,092	29,649	30,530	31,080	29,959
2013	34,376	35,559	36,185	33,970	29,865	30,896	31,419	30,106
2014	34,571	35,995	36,699	33,953	30,249	31,457	32,022	30,438
2015	34,678	36,323	37,132	33,793	30,476	31,825	32,473	30,575
2016	34,898	36,741	37,681	33,700	30,875	32,336	33,107	30,849
2017	35,130	37,167	38,249	33,577	31,299	32,862	33,763	31,122
2018	35,313	37,525	38,718	33,322	31,660	33,295	34,274	31,267
2019	35,420	37,807	39,109	32,970	31,922	33,629	34,676	31,307
2020	35,412	37,977	39,397	32,479	32,027	33,800	34,923	31,193
2021	35,557	38,350	39,926	32,191	32,359	34,262	35,513	31,378
2022	35,734	38,783	40,550	31,948	32,734	34,805	36,224	31,667
2023	35,907	39,237	41,235	31,731	33,102	35,371	37,008	32,004
2024	36,056	39,698	41,937	31,501	33,431	35,934	37,799	32,341
2025	36,211	40,177	42,666	31,365	33,764	36,509	38,615	32,647
2026	36,352	40,655	43,405	31,244	34,106	37,101	39,432	32,950
2027	36,487	41,159	44,187	31,293	34,441	37,740	40,320	33,355
2028	36,637	41,693	45,033	31,466	34,808	38,423	41,305	33,855
2029	36,786	42,245	45,898	31,668	35,174	39,133	42,317	34,392
2030	36,949	42,814	46,788	32,202	35,559	39,865	43,360	35,043
2010-2030	0.5%	1.1%	1.5%	-0.25%	1.1%	1.6%	1.9%	0.94%