6

Demand Forecasts

The system-level demand forecast that PSE develops for the IRP is an estimate of energy sales, customer counts and peak demand over a 20-year period. These forecasts are designed for use in long-term resource planning and in Delivery System Planning (DSP) needs assessments.

Contents

1. OVERVIEW

The demand forecasts developed for the IRP estimate the amount of electricity or natural gas that will be required to meet the needs of customers over the 20+ year study period. These forecasts focus on two dimensions of demand: energy demand and peak demand.

- Energy demand refers to the total amount of electricity or natural gas needed to meet customer needs in a given year.
- Peak demand refers to the amount of electricity or natural gas needed to serve customer need on the coldest day of the year, since PSE is a winter-peaking utility.

NOTE: The terms “demand” and “load” are often used interchangeably, but they actually refer to different concepts. “Demand” refers to the amount of energy needed to meet the needs of customers during a calendar year, including losses. “Load” refers to demand plus the planning margin and operating reserves needed to ensure reliable and safe operation of the electric and natural gas systems.

Overall, electric energy demand before additional conservation in the 2021 IRP Base Demand Forecast is expected to grow at an average annual rate of 1.2 percent during the study period from 2022 to 2045, resulting in an increase from 2,500 aMW in 2022 to 3,316 aMW in 2045. This is slower than the 1.4 average annual energy growth rate forecast during the 2019 IRP Process. Electric peak demand before additional conservation is expected to increase at a 1.2 percent annual growth rate, resulting in an increase from 4,687 MW in 2022 to 6,159 MW in 2045. This is also slower than the 1.3 percent average annual growth rate forecast during the 2019 IRP Process and results in lower total peak demand at the end of the study period. System growth is driven by customer additions. Demand from customers using electric vehicles drives up residential and commercial use per customer in the second half of the study period.

The 2021 IRP Natural Gas Base Demand Forecast before additional conservation for both energy and peak demand is also lower than forecast during the 2019 IRP Process. However, for energy, the average annual growth rate (0.8 percent) is higher compared to the 2019 IRP Process (0.7 percent). For peak demand, the average annual growth rate in the 2021 IRP forecast is the same as that in the 2019 IRP Process (0.8 percent). Lower residential customer counts, lower residential use per customer, lingering COVID-19 effects, and the inclusion of recent data on cold weather days in calculating weather sensitivity reduced demand.

In this IRP, the Base Demand Forecast is based on “normal” weather, defined as the average monthly weather recorded at NOAA’s Sea-Tac Airport station over the 30 years ending in 2019. For the 2021 IRP, the natural gas and electric analysis included a temperature sensitivity on demand. PSE proposed three alternative temperature assumptions to stakeholders, and stakeholders selected the temperature assumption with the greatest warming trend. This sensitivity has temperatures warming over time following the trend of one model that the Northwest Power and Conservation Council is using in its climate analyses. More information on this sensitivity can be found in Chapter 5, Key Analytical Assumptions, and the related demand forecast is discussed later in this chapter.

To model a range of potential economic conditions, weather conditions and potential modeling errors in the IRP analysis, PSE also prepares Low and High forecasts in addition to the Base Forecast. The Low Forecast models reduced population and economic growth compared to the Base Forecast; the High Forecast models higher population and economic growth compared to the Base Forecast. For the High and Low Demand Forecasts, historic monthly temperature observations are used to project a distribution of possible future temperature-sensitive demand, thereby modeling a wider range of warmer and colder conditions than the Base Demand Forecast.

CONSERVATION IMPACTS. Demand is reduced significantly when forward projections of additional conservation savings are applied, as shown in Figure 6-1. However, it is necessary to start with forecasts that do not already include forward projections of conservation savings in order to identify the most cost-effective amount of conservation to include in the resource plan.

NOTE: Throughout this chapter, charts labeled “before additional DSR” include only demand-side resource (DSR) measures implemented before the study period begins in 2022. Charts labeled “after applying DSR” include the cost-effective amount of DSR identified in the 2021 IRP.

Figure 6-1: Effect of Conservation Impacts on Demand Forecasts

2021 IRP Base Forecast at End of Forecast Period	Before Additional DSR	After Applying DSR
Electric Energy Demand (aMW) (2045)	3,316	2,604
Electric Peak Demand (MW) (2045)	6,159	4,966
Natural Gas Energy Demand (Mdth) (2041)	112,918	100,678
Natural Gas Peak Demand (Mdth) (2041)	1,130	1,019

2. ELECTRIC DEMAND FORECAST

Highlights of the IRP Base, High and Low Demand Forecasts developed for the electric service area are presented below in Figures 6-2 through 6-5. The population and employment assumptions for all three forecasts are summarized in the section titled "Details of Electric Forecast" and explained in detail in Appendix F, Demand Forecasting Models.

Only DSR measures implemented through December 2021 are included, since the demand forecast itself helps to determine the most cost-effective amount of conservation to include in the portfolio.

Electric Energy Demand

In the 2021 IRP Base Demand Forecast, energy demand before additional DSR is expected to grow at an average rate of 1.2 percent annually from 2022 to 2045, increasing energy demand from 2,500 aMW in 2022 to 3,316 aMW in 2045.

Residential and commercial demand are driving the growth in total energy. Excluding losses, these customer classes are projected to represent 50 percent and 38 percent of demand in 2022, respectively. On the residential side, use per customer is expected to be relatively flat for the short term but to grow over time, mainly due to the adoption of electric vehicles. This, plus population growth, is driving residential energy demand. On the commercial side, use per customer is relatively flat as well, with a small amount of growth in the later part of the forecast due to electric vehicle growth. Rising customer counts therefore drive much of the growth.

The 2021 IRP High Demand Forecast projects an average annual growth rate (AARG) of 1.6 percent; the Low Demand Forecast projects 0.9 percent.

Figure 6-2: Electric Energy Demand Forecast before Additional DSR

Base, High and Low Scenarios (aMW)

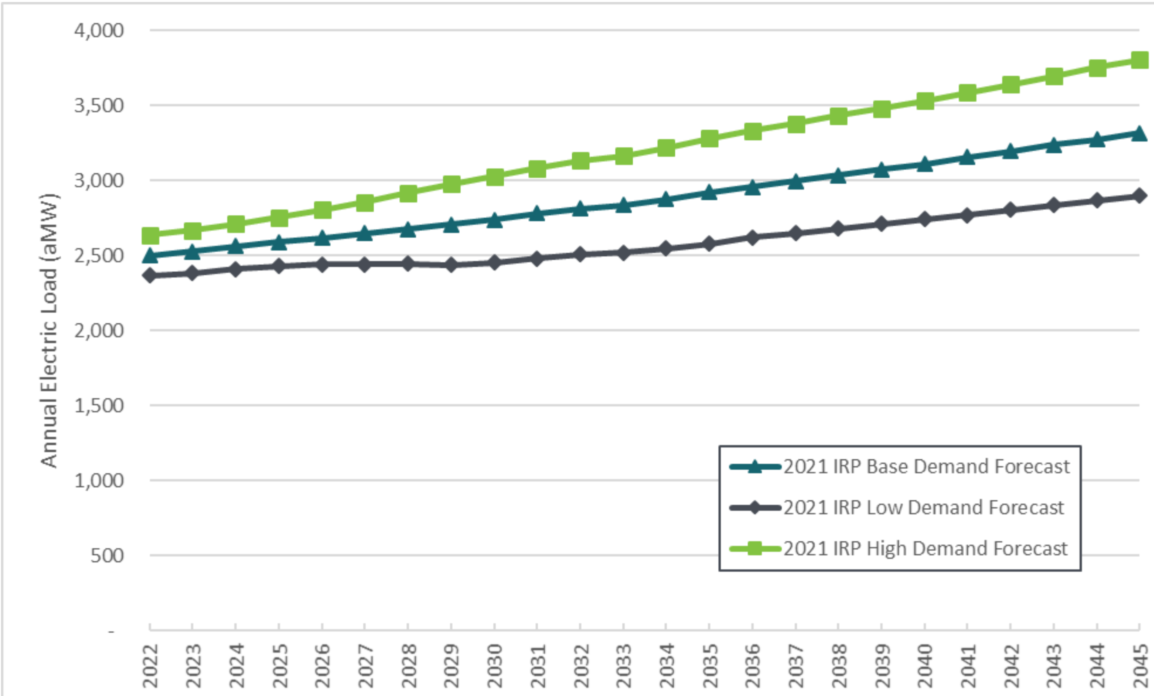


Figure 6-3: Electric Energy Demand Forecast before Additional DSR (Table)
Base, High and Low Scenarios

2021 IRP ELECTRIC ENERGY DEMAND FORECAST SCENARIOS (aMW)							
Scenario	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**	**AARG 2022-2045**
2021 IRP Base Demand Forecast	2,500	2,592	2,740	2,921	3,110	3,316	1.2%
2021 IRP High Demand Forecast	2,636	2,753	3,029	3,281	3,531	3,803	1.6%
2021 IRP Low Demand Forecast	2,367	2,429	2,454	2,580	2,742	2,897	0.9%

Electric Peak Demand

PSE is a winter peaking utility, meaning that the one hour during the year with the highest demand occurs during the winter. The capacity expansion model analyzes winter peaks. However, summer peaks are growing with warming summer temperatures and increased saturation of air conditioning in the region. Different types of supply-side or demand-side resources may better meet a summer or a winter peak. Therefore, PSE considers demand during all hours of the year in the resource adequacy modeling to help determine the best resources to meet load from our customers. This section describes the winter and summer electric peaks.

Winter Electric Peak Demand

The normal electric winter peak hour demand is modeled using 23 degrees Fahrenheit as the design temperature. Since PSE is a winter peaking utility, this peak has historically occurred in December but is occurring in other winter months as well. The 2021 IRP Base Demand Forecast shows a 1.2 percent average annual growth rate for peak demand; this would increase peak demand from 4,687 MW in 2022 to 6,159 MW in 2045.

The 2021 IRP High Demand Forecast shows an average annual peak demand growth rate of 1.5 percent, and the Low Demand Forecast shows a 0.9 percent average annual growth rate.

Figure 6-4: Winter Electric Peak Demand Forecast before Additional DSR Base, High and Low Scenarios, Hourly Annual Peak (MW)

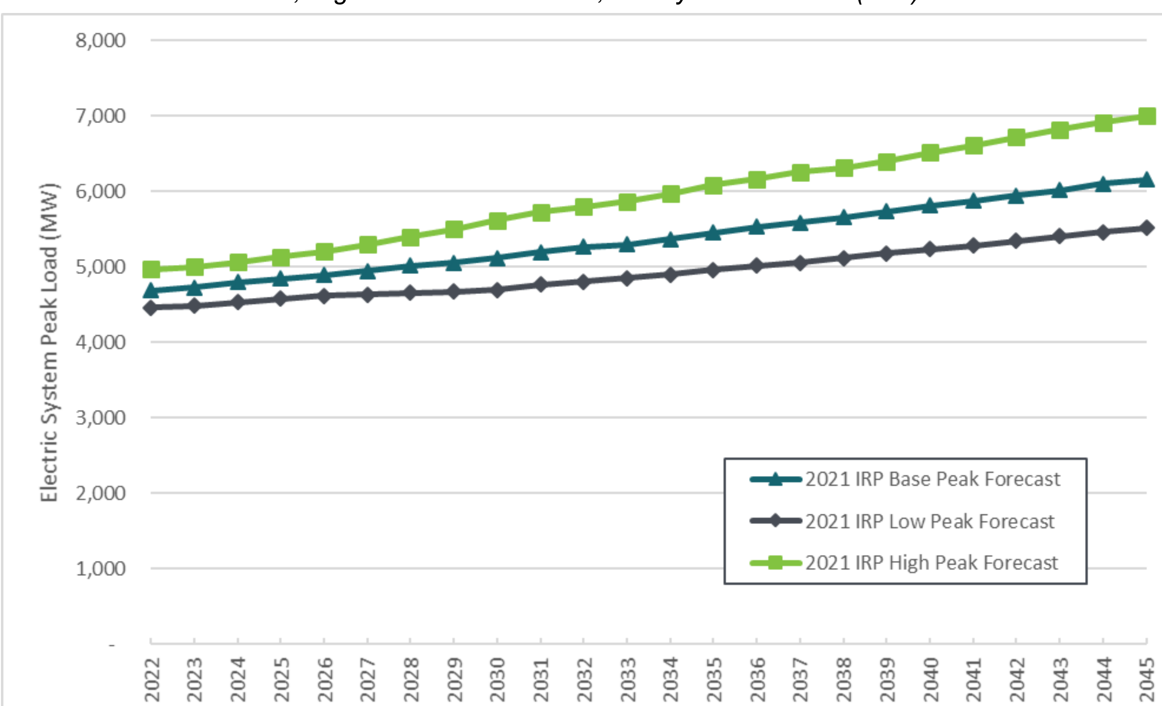
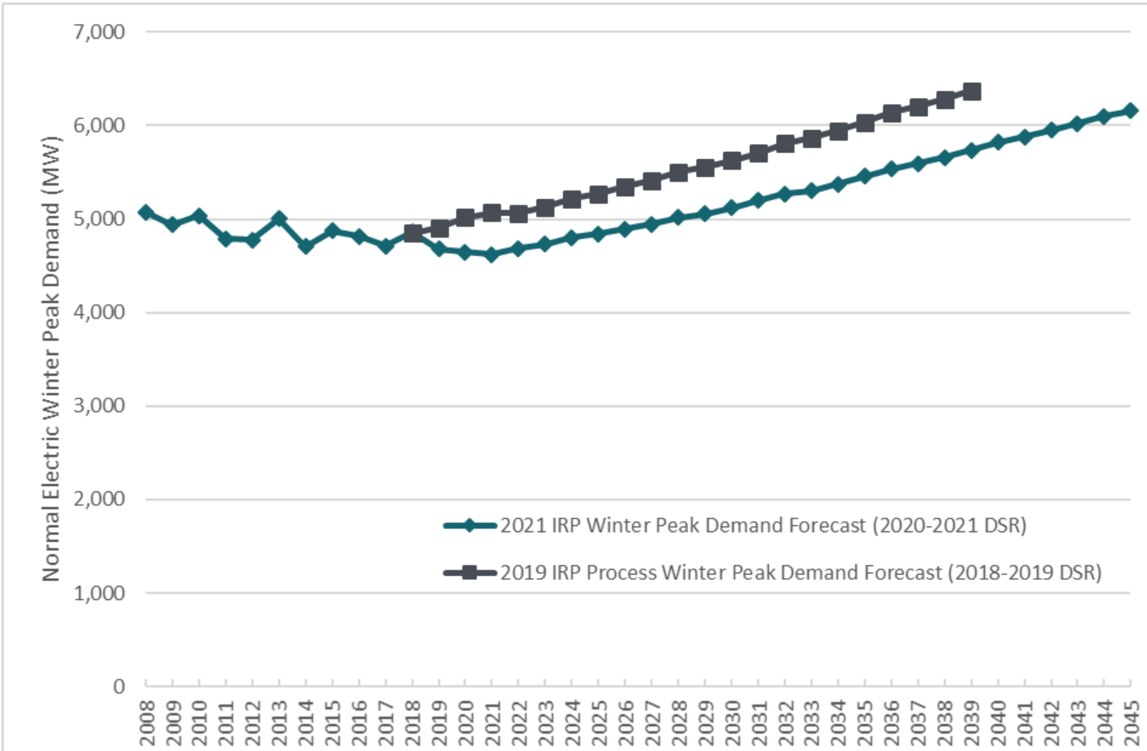


Figure 6-5: Winter Electric Peak Demand Forecast before Additional DSR (Table)
Base, High and Low Scenarios, Hourly Annual Peak (MW)

2021 IRP WINTER ELECTRIC PEAK DEMAND FORECAST SCENARIOS (MW)							
Scenario	2022	2025	2030	2035	2040	2045	AARG 2022-2045
2021 IRP Base Demand Forecast	4,687	4,844	5,123	5,455	5,819	6,159	1.2%
2021 IRP High Demand Forecast	4,972	5,138	5,622	6,085	6,521	7,001	1.5%
2021 IRP Low Demand Forecast	4,466	4,581	4,697	4,966	5,240	5,519	0.9%

Peak demand in the 2021 IRP Base Demand Forecast is lower at the end of the study period (6,159 MW in 2040) compared to the 2019 IRP Process (6,370 MW in 2039). Additionally, the 2021 IRP Peak Demand Forecast has a slower average annual growth rate (1.2 percent) compared to the 2019 IRP Process (1.3 percent). The 2021 IRP Peak Demand Forecast projects slower growth than the 2019 IRP Process Peak Demand Forecast because the 2021 IRP Demand Forecast grows at a slower rate than the 2019 IRP Process due to slower anticipated customer growth (particularly commercial) and lower projected use per customer in all non-residential classes. Observed actual residential customers and sales growth in 2018 and 2019 offset the non-residential trends; however, the downward growth drivers related to lower commercial usage and COVID-19 result in a lower long-term growth rate.

Figure 6-6: Winter Electric Peak Demand Forecast before Additional DSR
2021 IRP Base Scenario versus 2019 IRP Process Base Scenario
Hourly Annual Peak (23 Degrees, MW)



Summer Electric Peak Demand

The normal electric summer peak hour demand is modeled using 93 degrees Fahrenheit as the design temperature. Summer peaks typically occur in July or August. Figure 6-7 shows the 2021 IRP Base Peak Demand Forecast for the winter and the summer. The 2021 IRP Base summer peak demand forecast has an average annual growth rate of 1.7 percent. This increases the summer peak demand from 3,515 MW in 2022 to 5,183 MW in 2045. Because the summer peak forecast does not exceed the winter peak forecast in the timeframe shown, it is assumed that PSE will continue to be a winter peaking utility for the planning period of this IRP.

Figure 6-7: Winter and Summer Electric Peak Demand Forecasts before Additional DSR Base Scenario, Hourly Annual Peak (MW)

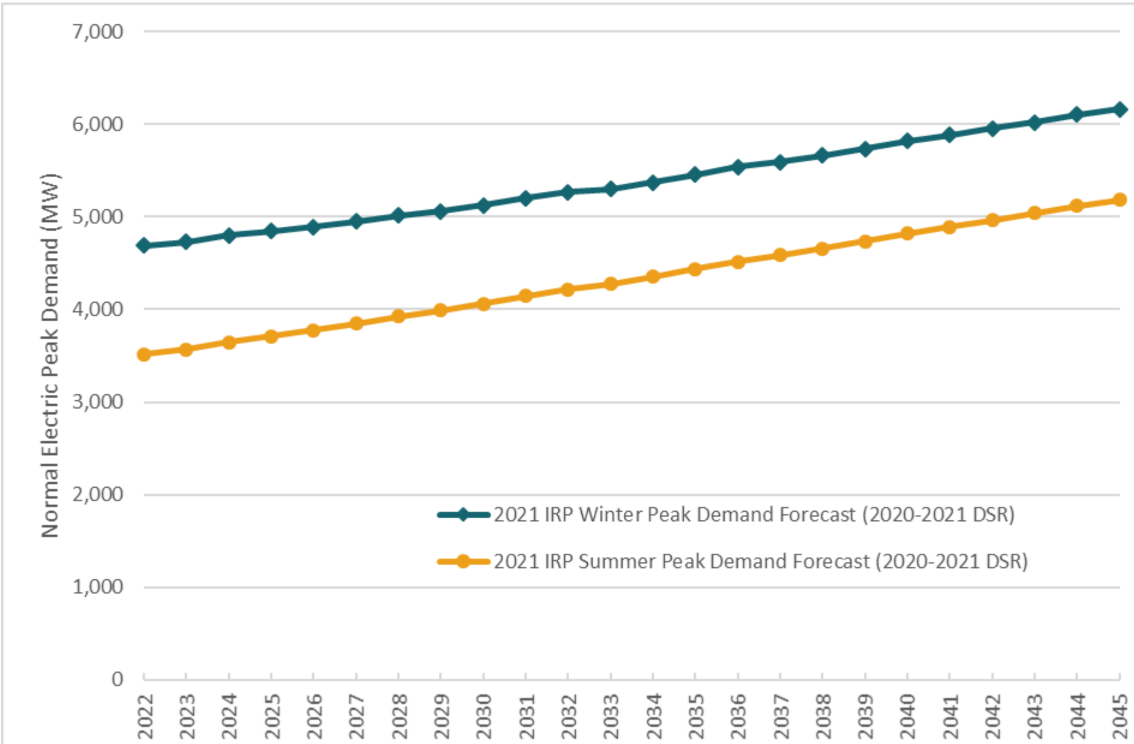


Illustration of Conservation Impacts

The system-level demand forecasts shown above apply only the energy efficiency measures targeted for 2020 and 2021, because those forecasts serve as the starting point for identifying the most cost-effective amount of demand-side resources for the portfolio from 2022 to 2045.

However, PSE also examines the effects of conservation on the energy and peak demand over the full planning horizon. Forecasts with conservation are used internally at PSE for financial and system planning decisions. To illustrate conservation impacts, the cost-effective demand-side resources identified in this IRP[1] are applied to the Base Scenario energy and peak demand forecasts for 2022 to 2045. To account for the 2013 general rate case Global Settlement, an additional 5 percent of conservation is also applied for that period. The results are illustrated in Figures 6-8 and 6-9, below.

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[1] / *For demand-side resource analysis, see Chapter 8, Electric Analysis, and Appendix E, Conservation Potential Assessment and Demand Response Assessment.*

DSR IMPACT ON ENERGY DEMAND. When the DSR bundles chosen in the 2021 IRP portfolio analysis are applied to the energy demand forecast:

- Electric energy demand in 2045 is reduced 21 percent to 2,604 aMW.
- Electric energy demand after DSR grows at an average annual rate of 0.23 percent from 2022 to 2045.

DSR IMPACT ON PEAK DEMAND. When the DSR bundles chosen in the 2021 portfolio analysis are applied to the peak demand forecast:

- Electric system peak demand in 2045 is reduced 19 percent to 4,966 MW.
- Electric system peak demand after DSR grows at an average annual rate of 0.3 percent from 2022 to 2045.

Figure 6-8: Electric Energy Demand Forecast (aMW), before Additional DSR and after Applying DSR

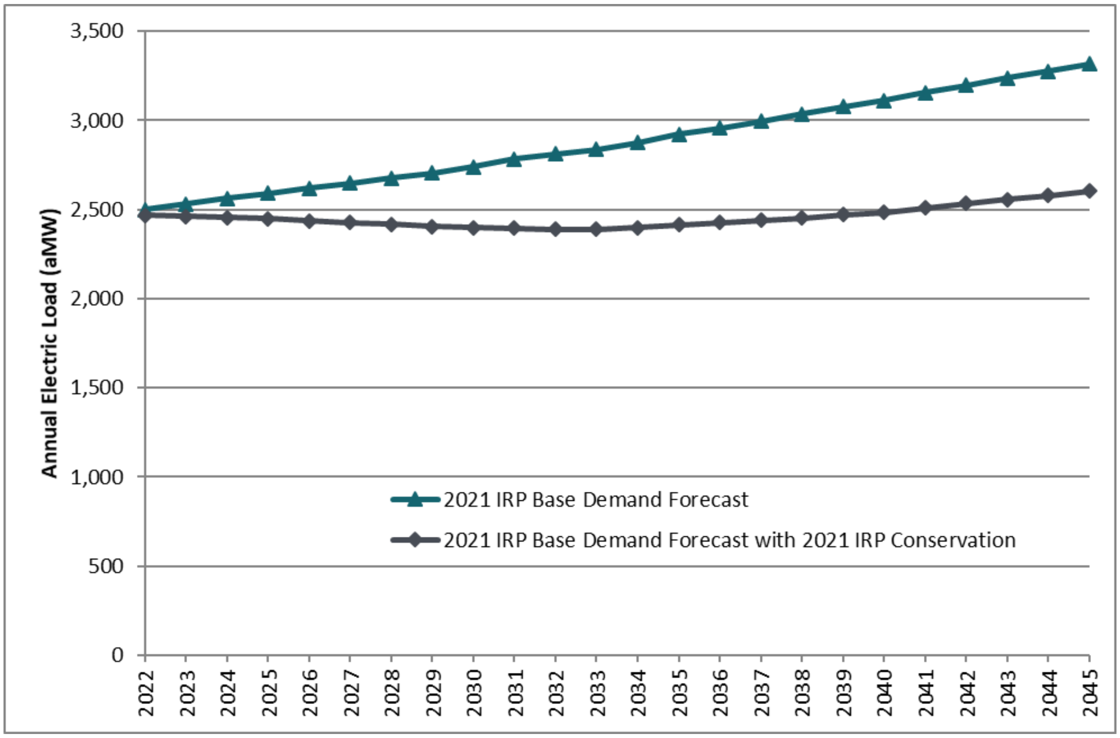
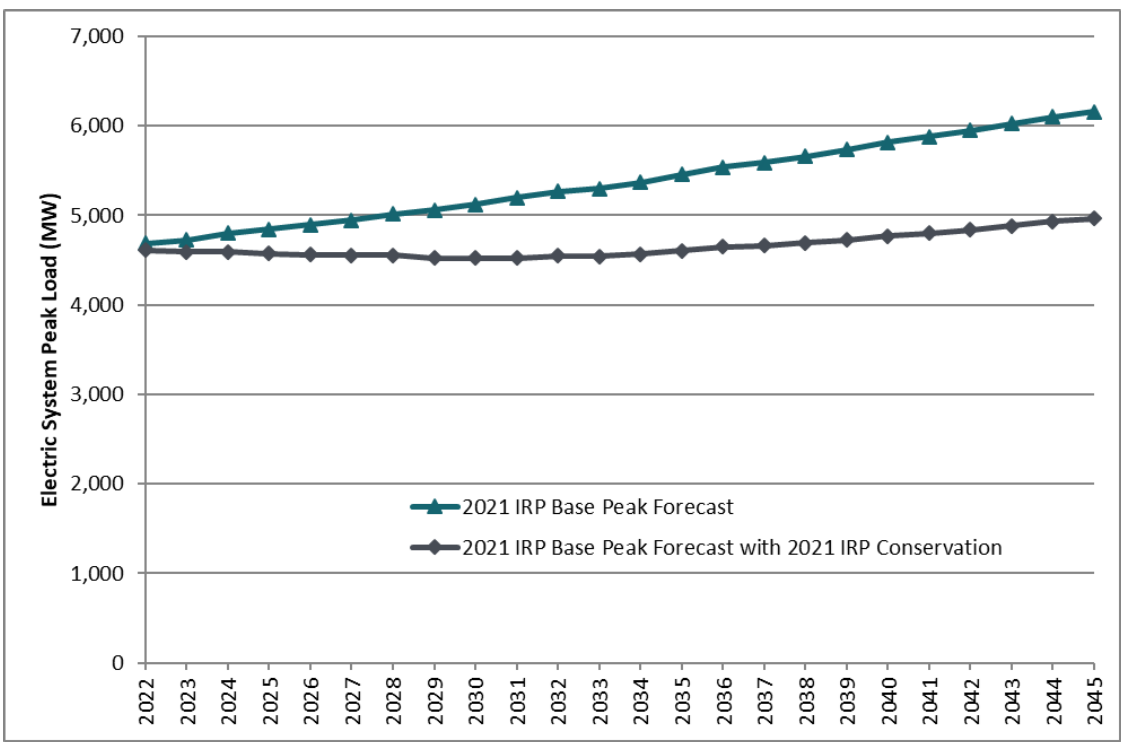


Figure 6-9: Electric Peak Demand Forecast (MW), before Additional DSR and after Applying DSR



Details of Electric Forecast

Electric Customer Counts

System-level customer counts are expected to grow by 1.0 percent per year on average, from 1.21 million customers in 2022 to 1.53 million customers in 2045. This is slower than the average annual growth rate of 1.2 percent projected in the 2019 IRP Process Base Demand Forecast.

Residential customers are driving the overall customer count increase, since they are projected to represent 88 percent of PSE's electric customers in 2022. Residential customer counts are expected to grow at an average annual rate of 1.0 percent from 2023 to 2045. The next largest group, commercial customers, is expected to grow at an average annual rate of 0.9 percent. Industrial customer counts are expected to decline, following a historical trend. These trends are expected to continue as the economy in PSE's service area shifts toward more commercial and less industrial industries.

Figure 6-10: December Electric Customer Counts by Class, 2021 IRP Base Demand Forecast

2021 IRP DECEMBER ELECTRIC CUSTOMER COUNTS BY CLASS, BASE DEMAND FORECAST							
Class	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**	**AARG 2022-2045**
Total	1,210,701	1,253,182	1,324,465	1,395,434	1,463,388	1,529,051	1.0%
Residential	1,066,293	1,103,799	1,167,538	1,230,936	1,291,536	1,349,980	1.0%
Commercial	133,023	137,547	144,357	151,236	157,975	164,647	0.9%
Industrial	3,249	3,193	3,106	3,023	2,948	2,882	-0.5%
Other	8,130	8,643	9,464	10,239	10,929	11,542	1.5%

Electric Demand by Class

Over the next 20 years, the residential and commercial classes are both expected to have positive demand growth, with the residential class growing faster than the commercial class, before conservation. Residential class demand growth is driven by new additional customers and projected adoption of electric vehicles. Commercial class demand growth is driven by growth in the region's technology sector, which also increases the need for support services such as health care, retail, education and other public services.

Figure 6-11: Electric Energy Demand by Class, 2021 IRP Base Demand Forecast before Additional DSR

ELECTRIC DEMAND BY CLASS, 2021 IRP BASE DEMAND FORECAST (aMW)							
Class	2022	2025	2030	2035	2040	2045	AARG 2022-2045
Total	2,500	2,592	2,740	2,921	3,110	3,316	1.2%
Residential	1,248	1,300	1,392	1,497	1,609	1,722	1.4%
Commercial	954	987	1,036	1,100	1,167	1,249	1.2%
Industrial	120	121	119	117	115	114	-0.2%
Other	8	8	8	8	7	7	-0.7%
Losses	170	176	186	199	211	226	-

Electric Use per Customer

Residential use per customer[2] before conservation is expected to decline in the short term but is forecast to grow over the long term. Near-term efficiency gains and multifamily housing growth will continue to reduce electric use per customer, but the forecast projects that the increasing adoption of electric vehicles will outweigh this and create slightly positive growth, especially in the later part of the forecast. Commercial use per customer is expected to decline in the short term, due to efficiency gains as well as lingering effects from the pandemic on the commercial sector. Commercial use per customer has some positive growth in the long term due to increasing electric vehicle growth.

Figure 6-12: Electric Use per Customer, 2021 IRP Base Demand Forecast before Additional DSR

2021 IRP ELECTRIC USE PER CUSTOMER, BASE DEMAND FORECAST (MWh/CUSTOMER)							
Type	2022	2025	2030	2035	2040	2045	AARG 2022-2045
Residential	10.3	10.4	10.5	10.7	11.0	11.2	0.4%
Commercial	63.1	63.1	63.0	63.9	65.1	66.6	0.2%
Industrial	321.9	330.5	333.6	337.3	341.4	344.7	0.3%

2 / *Use per customer is defined as billed energy sales per customer, that is, the amount of energy consumed at the meter.*

Electric Customer Count and Energy Demand Share by Class

Customer counts as a percent of PSE's total electric customers are shown in Figure 6-13. Demand share by class is shown in Figure 6-14. The residential class is expected to increase as a percent of both total customers and total demand, and the commercial class is expected to decline as a percent of both.

Figure 6-13: December Electric Customer Count Share by Class, 2021 IRP Base Demand Forecast

ELECTRIC CUSTOMER COUNT SHARES BY CLASS, 2021 IRP BASE DEMAND FORECAST		
Class	**Share in 2022**	**Share in 2045**
Residential	88.1%	88.3%
Commercial	11.0%	10.8%
Industrial	0.3%	0.2%
Other	0.7%	0.8%

Figure 6-14: Electric Demand Share by Class, 2021 IRP Base Demand Forecast before Additional DSR

ELECTRIC DEMAND SHARES BY CLASS, 2021 IRP BASE DEMAND FORECAST		
Class	**Share in 2022**	**Share in 2045**
Residential	49.9%	51.9%
Commercial	38.1%	37.6%
Industrial	4.8%	3.4%
Other	0.3%	0.2%
Losses	6.8%	6.8%

3. NATURAL GAS DEMAND FORECAST

Highlights of the base, high and low demand forecasts developed for PSE's natural gas sales service are presented below. The population and employment assumptions for all three forecasts are summarized in the section titled "Details of the Natural Gas Forecast" and explained in detail in Appendix F, Demand Forecasting Models.

Only demand-side resources implemented through December 2021 are included, since the demand forecast itself helps to determine the most cost-effective level of DSR to include in the portfolio.

Natural Gas Energy Demand

The 2021 IRP Natural Gas Base Demand Forecast is a forecast of both firm and interruptible demand, because this is the volume of natural gas that PSE is responsible for securing and delivering to customers. For delivery system planning, however, transport demand must be included in total demand; transport customers purchase their own natural gas, but contract with PSE for delivery.

In the 2021 IRP Base Demand Forecast, natural gas energy demand before additional DSR is projected to grow 0.8 percent per year on average from 2022 to 2041; this would increase demand from 96,156 MDth in 2022 to 112,918 MDth in 2041. This is slightly higher than the annual growth rate of 0.7 percent in the 2019 IRP Process Base Demand Forecast. While the growth rate is higher, the levels of demand are lower in the 2021 IRP Base Demand Forecast than in the 2019 IRP Process Demand Forecast because lower residential customer additions, lower residential usage in the first half of the forecast and lingering COVID-19 pandemic effects lower demand in the first part of the forecast, compared to the 2019 IRP Process Forecast.

Before additional DSR, the 2021 IRP High Natural Gas Demand Forecast projects an average annual growth rate of 1.4 percent; the Low Natural Gas Demand Forecast projects a growth rate of 0.2 percent per year.

Figure 6-15: Natural Gas Energy Demand Forecast before Additional DSR Base, High and Low Scenarios, without Transport Load (MDth)

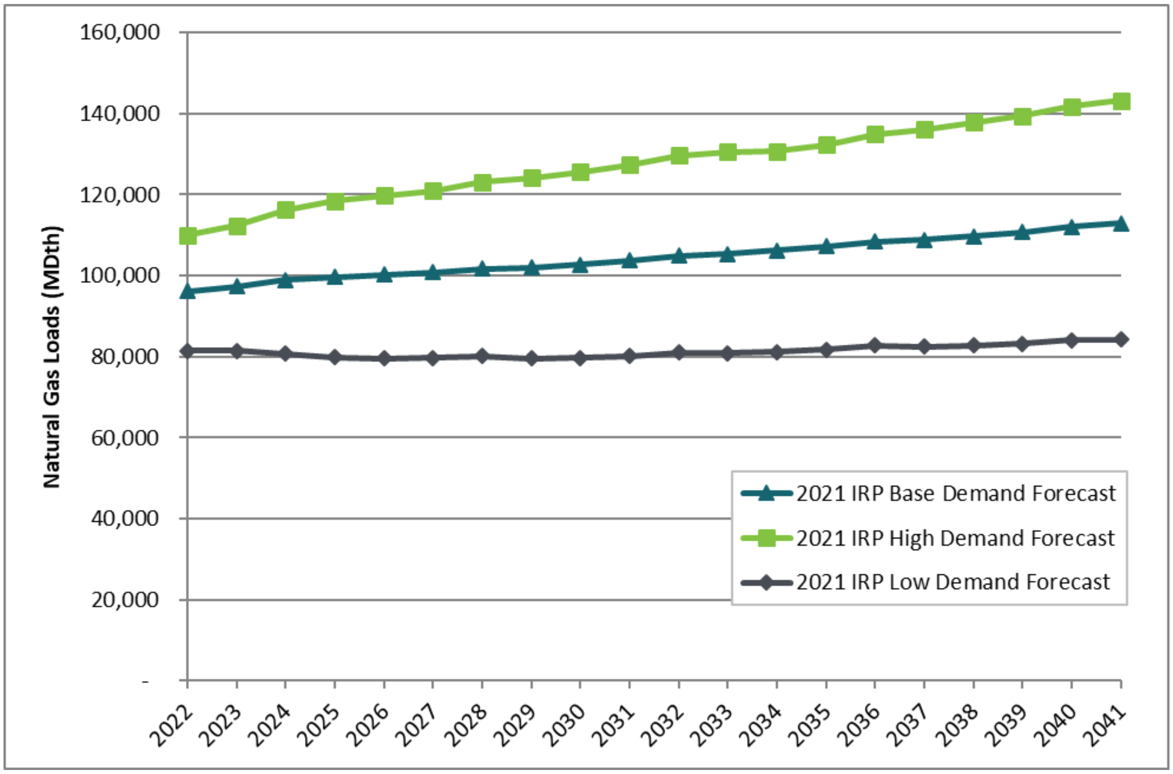


Figure 6-16: Natural Gas Energy Demand Forecast before Additional DSR (Table) Base, High and Low Scenarios without Transport (MDth)

2021 IRP NATURAL GAS ENERGY DEMAND FORECAST SCENARIOS (MDth), WITHOUT TRANSPORT						
Scenario	2022	2025	2030	2035	2041	AARG 2022-2041
2021 IRP Base Demand Forecast	96,156	99,653	102,769	107,195	112,918	0.8%
2021 IRP High Demand Forecast	110,024	118,424	125,542	132,321	143,261	1.4%
2021 IRP Low Demand Forecast	81,498	79,852	79,680	81,707	84,266	0.2%

Natural Gas Peak Demand

The natural gas design peak day is modeled at 13 degrees Fahrenheit average temperature for the day. Only firm sales customers are included when forecasting peak natural gas demand; transportation and interruptible customers are not included.

For peak natural gas demand, the 2021 IRP Base Demand Forecast projects an average increase of 0.8 percent per year from 2022 to 2041; peak demand would rise from 967 MDth in 2022 to 1,130 MDth in 2041. The High Demand Forecast projects a 1.1 percent annual growth rate, and the Low Demand Forecast projects 0.6 percent.

Figure 6-17: Natural Gas Peak Day Demand Forecast before Additional DSR Base, High and Low Scenarios (13 Degrees, MDth)

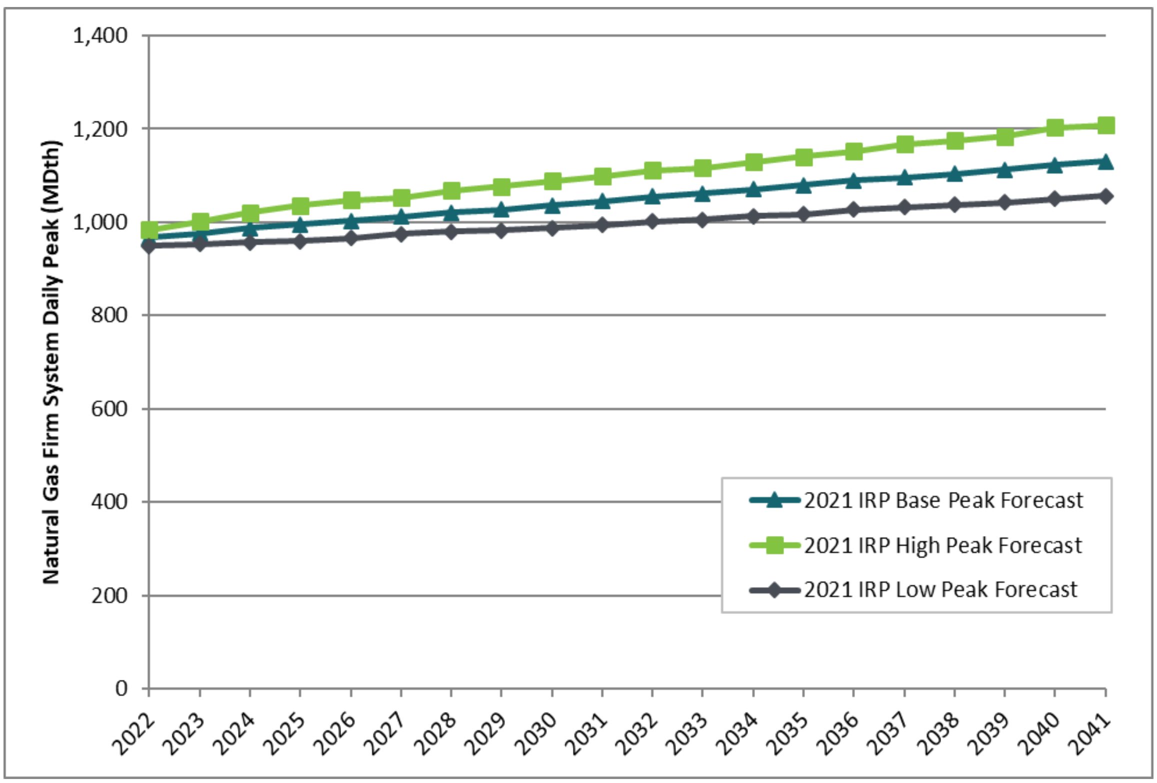


Figure 6-18: Natural Gas Peak Day Demand Forecast before Additional DSR (Table)
Base, High and Low Scenarios (13 Degrees, MDth)

2021 IRP FIRM NATURAL GAS PEAK DAY FORECAST SCENARIOS (MDth)						
Scenario	**2022**	**2025**	**2030**	**2035**	**2041**	**AARG 2022-2041**
2021 IRP Base Demand Forecast	967	995	1,036	1,079	1,130	0.8%
2021 IRP High Demand Forecast	984	1,036	1,088	1,141	1,208	1.1%
2021 IRP Low Demand Forecast	950	960	988	1,017	1,056	0.6%

The peak demand growth rate in the 2021 Base Demand Forecast is the same as the growth rate in the 2019 IRP Process (0.8 percent), but the highest levels of peak are lower in the 2021 IRP. This is partially due to the lower customer forecast, especially in the latter years of the forecast period, and the lingering effects of the COVID-19 pandemic in the first few years of the forecast period. Also, cold winter weather in 2018 and 2019 allowed the 2021 IRP natural gas peak forecast model to better capture the sensitivity of customers to cold weather.

Figure 6-19: Firm Natural Gas Peak Day Forecast before Additional DSR
2021 IRP Base Scenario versus 2019 IRP Process Base Scenario
Daily Annual Peak (13 Degrees, MDth)

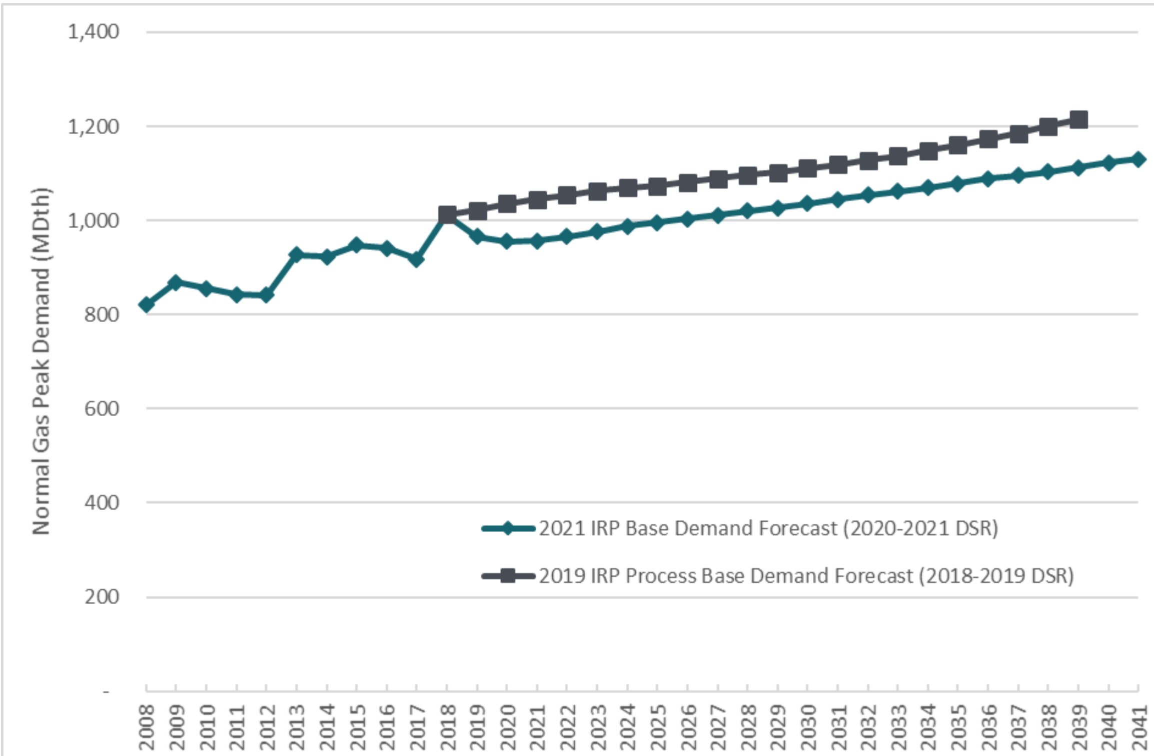


Illustration of Conservation Impacts

As explained at the beginning of the chapter, the natural gas demand forecasts include only demand-side resources implemented through December 2021, since the demand forecast itself helps to determine the most cost-effective level of DSR to include in the portfolio. To examine the effects of conservation on the energy and peak forecasts, the cost-effective amount of DSR determined in this IRP[3] is applied to the energy demand (without transport) and peak demand forecast for 2022 to 2041. To account for the 2017 General Rate Case, an additional 5 percent of conservation is also applied for that period. Forecasts with conservation are used internally at PSE for financial and system planning decisions. The results are illustrated in Figures 6-20 and 6-21, below.

DSR IMPACT ON ENERGY DEMAND. When the DSR bundles chosen in the 2021 IRP portfolio analysis are applied:

- Natural gas energy demand in 2041 is reduced 10.8 percent to 100,678 Mdth.
- Natural gas energy demand grows at an average annual rate of 0.26 percent from 2022 to 2041.

DSR IMPACT ON PEAK DEMAND. When the DSR bundles chosen in the 2021 IRP portfolio analysis are applied:

- Natural gas system peak demand in 2041 is reduced 9.8 percent to 1,019 Mdth.
- Natural gas system peak demand grows at an average annual rate of 0.3 percent from 2022 to 2041.

3 / For demand-side resource analysis, see Chapter 9, Natural Gas Analysis, and Appendix E, Conservation Potential Assessment.

Figure 6-20: Natural Gas Base Demand Forecast for Energy, before Additional DSR and after Applying DSR

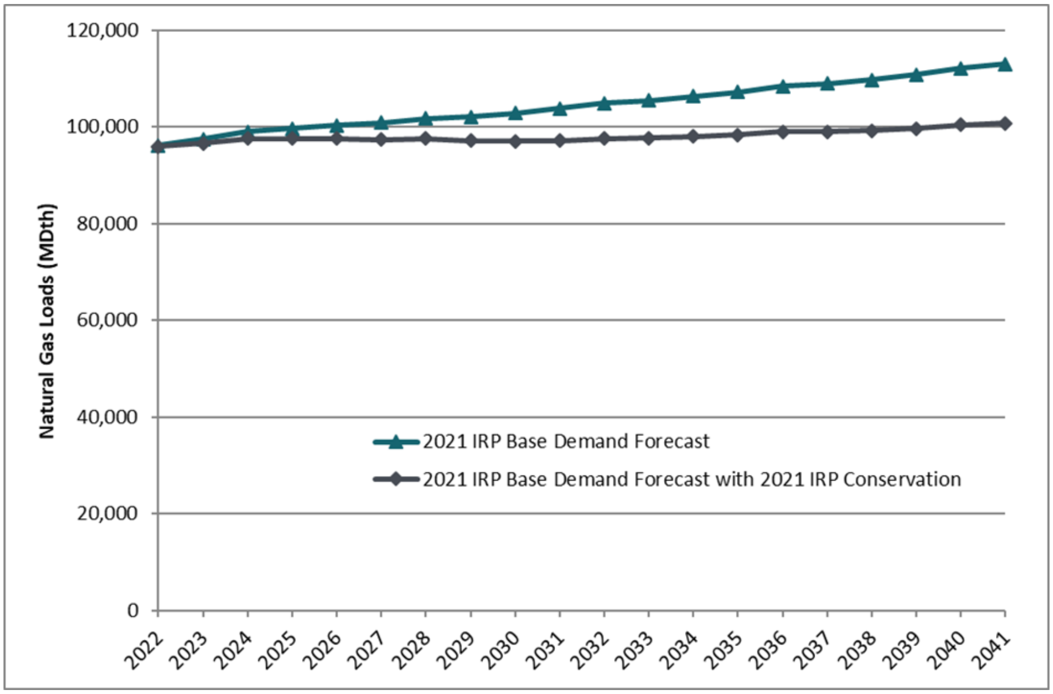
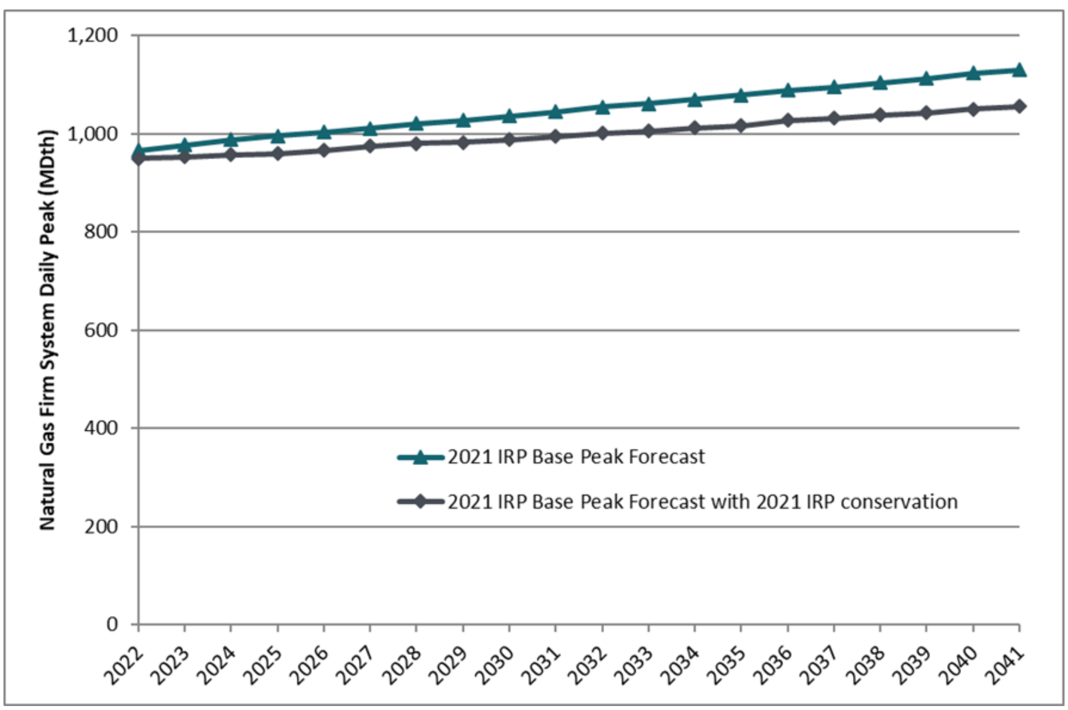


Figure 6-21: Natural Gas Peak Day Base Demand Forecast, before Additional DSR and after Applying DSR



Details of Natural Gas Forecast

Natural Gas Customer Counts

The Base Demand Forecast projects the number of natural gas customers will increase at a rate of 1.0 percent per year on average between 2022 and 2041, reaching 1.059 million customers by the end of the forecast period for the system as a whole. Overall, customer growth is slower than the 1.3 percent average annual growth rate projected in the 2019 IRP Process for 2020 to 2039.

Residential customer counts drive the growth in total customers, since this class makes up 93 percent of PSE's natural gas sales customers. Residential customer counts are expected to grow at an average annual rate of 1.0 percent from 2022 to 2041. The next largest group, commercial customers, is expected to grow at an average annual rate of 0.6 percent from 2022 to 2041. Industrial and interruptible customer classes are expected to continue to shrink, consistent with historical trends.

Figure 6-22: December Natural Gas Customer Counts by Class, 2021 IRP Base Demand Forecast

DECEMBER NATURAL GAS CUSTOMER COUNTS BY CLASS 2021 IRP BASE DEMAND FORECAST						
Customer Type	**2022**	**2025**	**2030**	**2035**	**2041**	**AARG 2022-2041**
Residential	817,317	845,918	892,765	939,222	993,155	1.0%
Commercial	57,264	58,444	60,095	61,734	63,666	0.6%
Industrial	2,244	2,191	2,103	2,016	1,910	-0.8%
Total Firm	876,825	906,553	954,963	1,002,972	1,058,731	1.0%
Interruptible	145	129	102	74	41	-6.4%
Total Firm & Interruptible	876,970	906,682	955,065	1,003,046	1,058,772	1.0%
Transport	225	225	225	225	225	0.0%
System Total	877,195	906,907	955,290	1,003,271	1,058,997	1.0%

Natural Gas Use per Customer

Table 6-23 below shows all firm use per customer at the meter.[4] Residential use per customer before conservation is slowly declining, showing a -0.1 percent average annual growth for the forecast period. Commercial use per customer is expected to rise 0.6 percent annually over the forecast horizon. Industrial use per customer has been declining in recent years and is expected to stay relatively flat. Note the commercial and industrial classes do not include interruptible or transport class usage. These classes can have very different sized customers and therefore the use per customer value can be skewed by very large customers.

Figure 6-23: Natural Gas Use per Customer before Additional DSR
2021 IRP Gas Base Demand Forecast

NATURAL GAS USE PER CUSTOMER (THERMS/CUSTOMER) 2021 IRP BASE DEMAND FORECAST						
Customer	2022	2025	2030	2035	2041	AARG 2022-2041
Residential	784	783	766	763	765	-0.1%
Commercial	4,960	5,122	5,234	5,376	5,553	0.6%
Industrial	10,685	10,691	10,692	10,692	10,694	0.0%

4 / Use per customer is defined as billed energy sales per customer, that is, the amount of energy consumed at the meter.

Natural Gas Demand by Class

Total energy demand, including transport, is expected to increase at an average rate of 0.7 percent annually between 2022 and 2041. Residential demand, which is forecast to represent 53 percent of demand in 2022, is expected to increase on average by 0.9 percent annually during the forecast period. Commercial demand, which is forecast to represent 24 percent of demand in 2022, is expected to increase 1.2 percent on average annually.

Population growth is driving residential demand growth. Commercial demand growth is driven by increases in both customer counts and use per customer. Demand in the industrial and interruptible sectors is expected to decline as manufacturing employment in the Puget Sound area continues to slow. Demand from the transport class is expected to grow slowly over time.

Figure 6-24: Natural Gas Energy Demand by Class (MDth), 2021 IRP Base Demand Forecast before Additional DSR

NATURAL GAS DEMAND (MDth) BY CLASS 2021 IRP BASE DEMAND FORECAST						
Class	**2022**	**2025**	**2030**	**2035**	**2041**	**AARG 2022-2041**
Residential	62,949	65,092	67,228	70,454	74,690	0.9%
Commercial	28,039	29,645	31,133	32,857	34,991	1.2%
Industrial	2,390	2,335	2,242	2,149	2,038	-0.8%
Total Firm	93,379	97,072	100,604	105,460	111,719	0.9%
Interruptible	2,585	2,382	1,960	1,520	974	-5.0%
Total Firm and Interruptible	95,964	99,454	102,564	106,981	112,692	0.8%
Transport	22,169	22,445	22,414	22,574	22,948	0.2%
System Total before Losses	118,133	121,899	124,978	129,555	135,641	0.7%
Losses	237	244	250	260	272	-
System Total	118,370	122,143	125,228	129,815	135,912	0.7%

Natural Gas Customer Count and Energy Demand Share by Class

Customer counts as a percent of PSE's total natural gas customers are shown in Figure 6-25. Demand share by class is shown in Figure 6-26.

Figure 6-25: Natural Gas Customer Count Share by Class 2021 IRP Base Demand Forecast

NATURAL GAS CUSTOMER COUNT SHARE BY CLASS, 2021 IRP BASE DEMAND FORECAST		
Class	Share in 2022	Share in 2041
Residential	93.2%	93.8%
Commercial	6.5%	6.0%
Industrial	0.3%	0.2%
Interruptible	0.02%	0.004%
Transport	0.03%	0.02%

Figure 6-26: Natural Gas Demand Share by Class, 2021 IRP Base Demand Forecast before Additional DSR

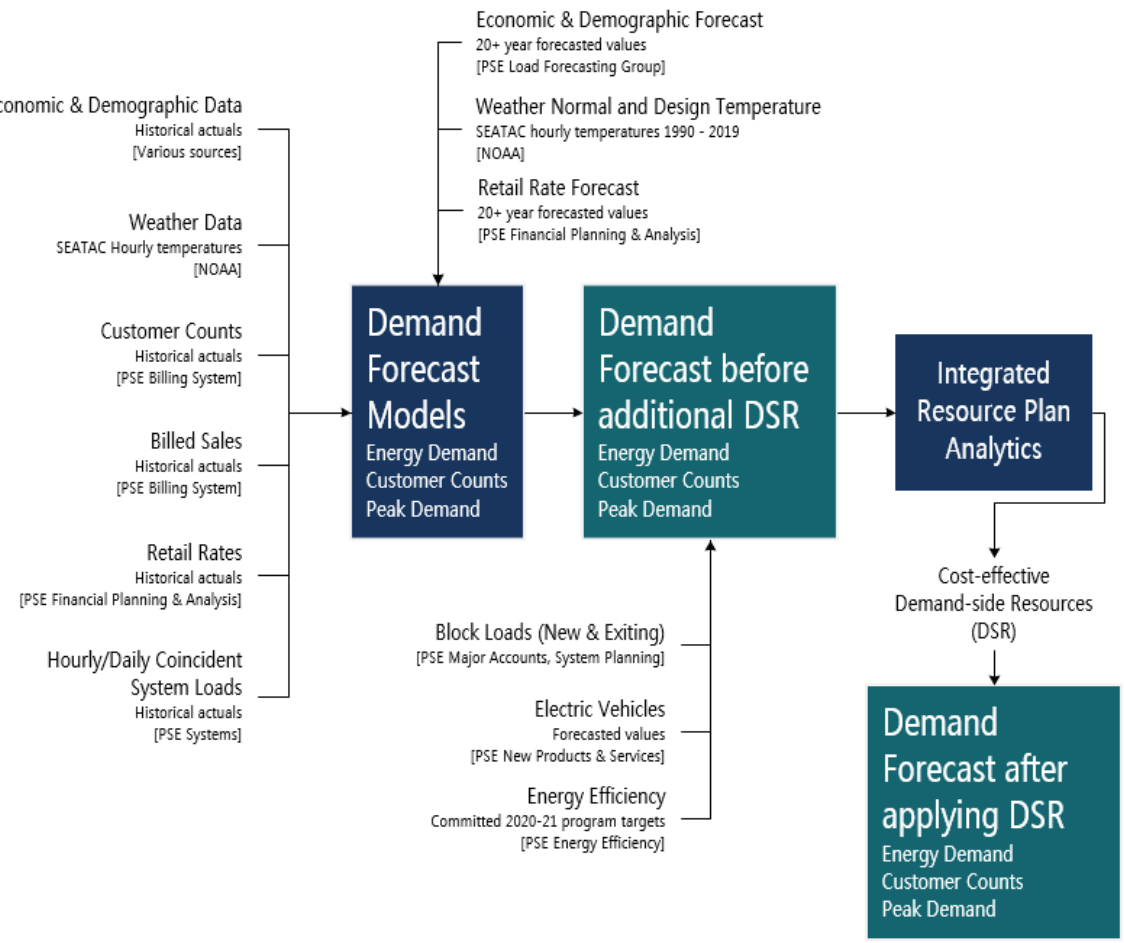
NATURAL GAS DEMAND SHARE BY CLASS, 2021 IRP BASE DEMAND FORECAST		
Class	Share in 2022	Share in 2041
Residential	53.2%	55.0%
Commercial	23.7%	25.7%
Industrial	2.0%	1.5%
Interruptible	2.2%	0.7%
Transport	18.7%	16.9%
Losses	0.2%	0.2%

4. METHODOLOGY

Forecasting Process

PSE's regional economic and demographic model uses both national and regional data to produce a forecast of total employment, types of employment, unemployment, personal income, households and consumer price index (CPI) for both the PSE electric and natural gas service territories. The regional economic and demographic data used in the model are built up from county level or metropolitan statistical area (MSA) level information from various sources. This economic and demographic information is combined with other PSE internal information to produce energy and peak demand forecasts for the service area. The demand forecasting process is illustrated in Figure 6-27, and the sources for economic and demographic input data are listed in Figure 6-28.

Figure 6-27: PSE Demand Forecasting Process



To forecast energy sales and customer counts, customers are divided into classes and service levels that use energy for similar purposes and at comparable retail rates. The different classes and/or service levels are modeled separately using variables specific to their usage patterns.

- Electric customer classes include residential, commercial, industrial, streetlights, resale and transport (customers purchasing their power not from PSE but from third-party suppliers).

- Natural gas customer classes include firm (residential, commercial, industrial, commercial large volume and industrial large volume), interruptible (commercial and industrial), and transport (commercial firm, commercial interruptible, industrial firm and industrial interruptible).

Transport Customers
"Transport" in the electric and natural gas industries has historically referred to customers that acquire their own electricity or natural gas from third-party suppliers and rely on the utility for distribution service. It does not refer to natural gas fueled vehicles or electric vehicles.

Multivariate time series econometric regression equations are used to derive historical relationships between trends and drivers, which are then employed to forecast the number of customers and use per customer by class or service level. These are multiplied together to arrive at the billed sales forecast. The main drivers of these equations include population, unemployment rates, retail rates, personal income, weather, total employment, manufacturing employment, consumer price index (CPI) and U.S. Gross Domestic Product (GDP). Demand, which is presented in this chapter, is calculated from sales and includes transmission and distribution losses in addition to sales. Weather inputs are based on temperature readings from Sea-Tac Airport. Peak system demand is also projected by examining the historical relationship between actual peaks, temperature at peaks, and the economic and demographic impacts on system demand.

> > > See Appendix F, Demand Forecasting Models*, for detailed descriptions of the econometric methodologies used to forecast billed energy sales, customer counts and peak loads for electricity and natural gas; hourly distribution of electric demand; and forecast uncertainty.*

Figure 6-28: Sources for U.S. and Regional Economic and Demographic Data

DATA USED IN ECONOMIC AND DEMOGRAPHIC MODEL	
County-level Data	**Source**
Labor force, employment, unemployment rate	U.S. Bureau of Labor Statistics (BLS) www.bls.gov
Total non-farm employment, and breakdowns by type of employment	WA State Employment Security Department (WA ESD), using data from Quarterly Census of Employment and Wages esd.wa.gov/labormarketinfo
Personal income	U.S. Bureau of Economic Analysis (BEA) www.bea.gov
Wages and salaries	
Population	WA State Employment Security Department (WA ESD) esd.wa.gov/labormarketinfo/report-library
Households, single- and multi-family	U.S. Census www.census.gov
Household size, single- and multi-family	
Housing permits, single- and multi-family	U.S. Census / Puget Sound Regional Council (PSRC) / City Websites / Building Industry Association of Washington (BIAW) www.biaw.com
Aerospace employment	Puget Sound Economic Forecaster www.economicforecaster.com
U.S.-level Data	**Source**
GDP	Moody's Analytics www.economy.com
Industrial Production Index	
Employment	
Unemployment rate	
Personal income	
Wages and salary disbursements	
Consumer Price Index (CPI)	
Housing starts	
Population	
Conventional mortgage rate	
T-bill rate, 3 months	

High and Low Scenarios

PSE also develops high and low growth scenarios by performing stochastic simulations with stochastic outputs from PSE's economic and demographic model, using historic weather to predict future weather.

- The natural gas high and low scenarios were modelled using 250 stochastic simulations.
- The electric high and low scenarios were created with an additional 60 simulations (for a total of 310), in order to capture variation in electric vehicle loads. The electric modeling also varied the seasonal design peak temperature.

The stochastic simulations reflect variations in key regional economic and demographic variables such as population, employment and income. They also vary the equation coefficients around the standard error of the coefficient to include potential model coefficient errors. In the electric scenarios, EV assumptions were held constant in 250 of the scenarios; a high EV forecast was applied to 30 scenarios; and a low EV forecast was applied to 30 scenarios. The high and low EV forecasts were derived using assumptions from the high and low EV scenarios in the July 2020 Pacific Northwest National Lab report, *Electric Vehicles at Scale – Phase I; Analysis: High EV Adoption Impacts on the Western U.S. Power Grid*. (The base EV forecast is described in more detail in Section 5 of this chapter, Chapter 5, Key Analytical Assumptions, and Chapter 4, Planning Environment.)

High and low growth scenarios also use historic weather scenarios that can reflect higher or lower temperature conditions. Historic weather scenarios use one year of weather data randomly drawn between 1990 and 2019 in each of the simulations. In contrast, the "normal" weather used for the base scenario is defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the 30 years ending in 2019. The low and high scenarios represent the 10th and 90th percentile of the simulations, respectively.

The high and low scenarios are run in the AURORA model to examine how a portfolio would change with high and low growth. The 310 electric stochastic scenarios are run in the AURORA portfolio model to test the robustness of the portfolio under various conditions. The 250 natural gas stochastic scenarios are run in SENDOUT. Detailed descriptions of the stochastics are available in Chapter 8, Electric Analysis, and Chapter 9, Natural Gas Analysis.

> > > ***See Appendix F, Demand Forecasting Models****, for a detailed discussion of the stochastic simulations.*

Resource Adequacy Model Inputs

In addition to the stochastics used to create the high and the low scenarios, PSE also develops 88 electric demand draws for the resource adequacy (RA) model. These demand draws are created with stochastic outputs from PSE's economic and demographic model and two consecutive historic weather years to predict future weather. Each historic weather year from 1929 to 2017 is represented in the 88 demand draws. Since the RA model examines a hydro year from October through September, drawing two consecutive years preserves the characteristics of each historic heating season. RA demand draws were created for the hydro years of 2027 to 2028 and 2031 to 2032.

Additionally, the RA model examines adequacy in each hour of a given future year; therefore, the RA model inputs are scaled to hourly demand using the hourly demand model, described in detail in Chapter 7, Resource Adequacy Analysis. To account for growth in electric vehicles, each of the 88 hourly demand forecasts was first created without electric vehicle demand. Then the hourly forecast of electric vehicle demand was added to each demand forecast, to create the final 88 hourly demand forecasts.

> > > See Chapter 7, Resource Adequacy Analysis *and* ***Appendix F, Demand Forecasting Models****, for detailed discussions of the hourly model.*

Temperature Sensitivity

PSE committed to run a future temperature sensitivity as part of the IRP. To that end, in addition to the definition of normal temperature used for the base energy demand model, PSE offered three alternative average temperature assumptions to the IRP stakeholders and asked them to select one of the options for further analysis. The three options used different future temperature assumptions, representing a wide range of future outcomes. PSE then ran a sensitivity based on the option chosen.

The three temperature sensitivities presented as options were:

1. **15-year normal temperature:** PSE currently uses a 30-year normal for the base demand forecast. That is, the average monthly weather recorded at NOAA's Sea-Tac Airport station over the 30 years ending in 2019. This normal weather is held constant into the future. The 15-year normal would instead use the most recent 15 years of weather data to create average monthly weather, and that weather would be held constant into the future. Option 1 results in the least amount of future warming.
2. **Historical trended temperature:** PSE contracted with Itron to examine the historic warming trend in temperatures at Sea-Tac Airport. The warming trend at Sea-Tac was determined to be linear over time at 0.4 degrees Fahrenheit warming per decade. This warming trend was then projected linearly into the future. A detailed write-up of this analysis is presented in Appendix L, Temperature Trend Study. Option 2 results in more future warming than Option 1, but less than Option 3.
3. **Council climate model:** A recent project by Bonneville Power Administration, U.S. Army Corps of Engineers, and the Bureau of Reclamation produced downscaled climate models for the Northwest region. The Northwest Power and Conservation Council (NWPCC) has been working with three of these models (CanESM2_BCSD, CCSM4_BCSD and CNRM-CM5_MACA). Each of these models is on the Representative Concentration Pathway of 8.5; some would argue this is a "business as usual" pathway, while others would argue that this is a more extreme climate warming scenario. The three models represent different amounts of warming over time. PSE presented the NWPCC model with the middle amount of warming (CCSM4_BCSD) as an option, which results in 0.9 degrees Fahrenheit of warming per decade. Option 3 represents a more extreme warming trend than Option 2.

Figure 6-29 below further describes the three future temperature options that IRP stakeholders chose from for this sensitivity.

Figure 6-29: Attributes of Temperature Sensitivity Options Compared to the Base Demand Forecast Temperatures Used

	Future Weather in Base Demand Model	Temperature Sensitivity Option 1	Temperature Sensitivity Option 2	Temperature Sensitivity Option 3
Description	30-year normal temperature	15-year normal temperature	Historical temperature trend (developed by Itron)	Council climate model
General Modeling Approach	Industry standard approach of using last 30 years of data to create flat projected temperature	Same methodology as 30-year normal, but using last 15 years of data	Uses historical warming trend to forecast future warming	Global Climate Model down-scaled to Pacific Northwest region
Weather Station Used	Sea-Tac	Sea-Tac	Sea-Tac	Sea-Tac
Historical Sea-Tac Weather Used	Last 30 years	Last 15 years	Data back to 1950 to develop a trend, 30-year normal used to define the starting point for the trend	Uses historic year of 1987 to map forecasted daily min and max temperatures to hourly temperatures
Global Climate Model, down-scaling method, and Representative Climate Pathway (RCP) assumed	NA	NA	NA, results similar to RCP 4.5	CCSM4_BCSD (Community Climate Systems Model v4: Bias Corrected Spatial Disaggregation), RCP 8.5
Energy Demand Modeling Approach	Uses last 30 years of data to create flat projected temperature for future	Uses last 15 years of data to create flat projected temperature for future	Uses historical trend to forecast warming trend in the future. Uses the middle of the last 30 years of weather as a starting point for weather trend.	Draw a trend line through the future temperatures to get warming per year. Uses the middle of the last 30 years of weather as a starting point for weather trend.
Average Warming in the Forecast Period for Energy Demand Modeling	0° F per decade	0° F per decade	0.4° F per decade	0.9° F per decade

To incorporate the future temperature options into the demand forecast, they first had to be converted into heating degree days (HDDs) and cooling degree days (CDDs). Heating and cooling degree days are a measure of how much heating or cooling is expected to be done by electric or natural gas appliances in a given month. Additional information on how to calculate heating and cooling degree days and how they factor into the demand forecast can be found in Appendix F, Demand Forecasting Models.

Figures 6-30 and 6-31 show the resulting heating degree days and cooling degree days from the three temperatures scenarios presented to the stakeholders compared to the current 30-year normal weather approach.

Figure 6-30: Annual Heating Degree Days (Base 65) for the Three Temperature Sensitivity Options Compared to 30-year Normal HDDs Used in the Base Demand Forecast

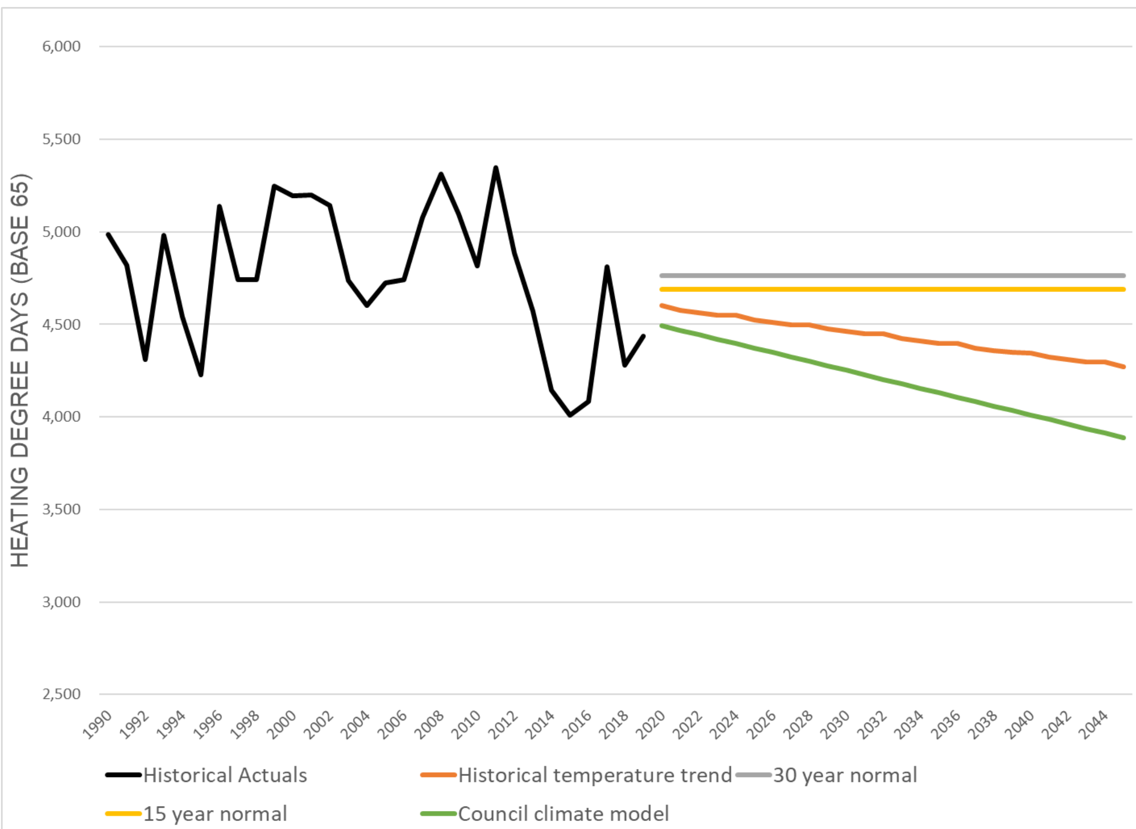
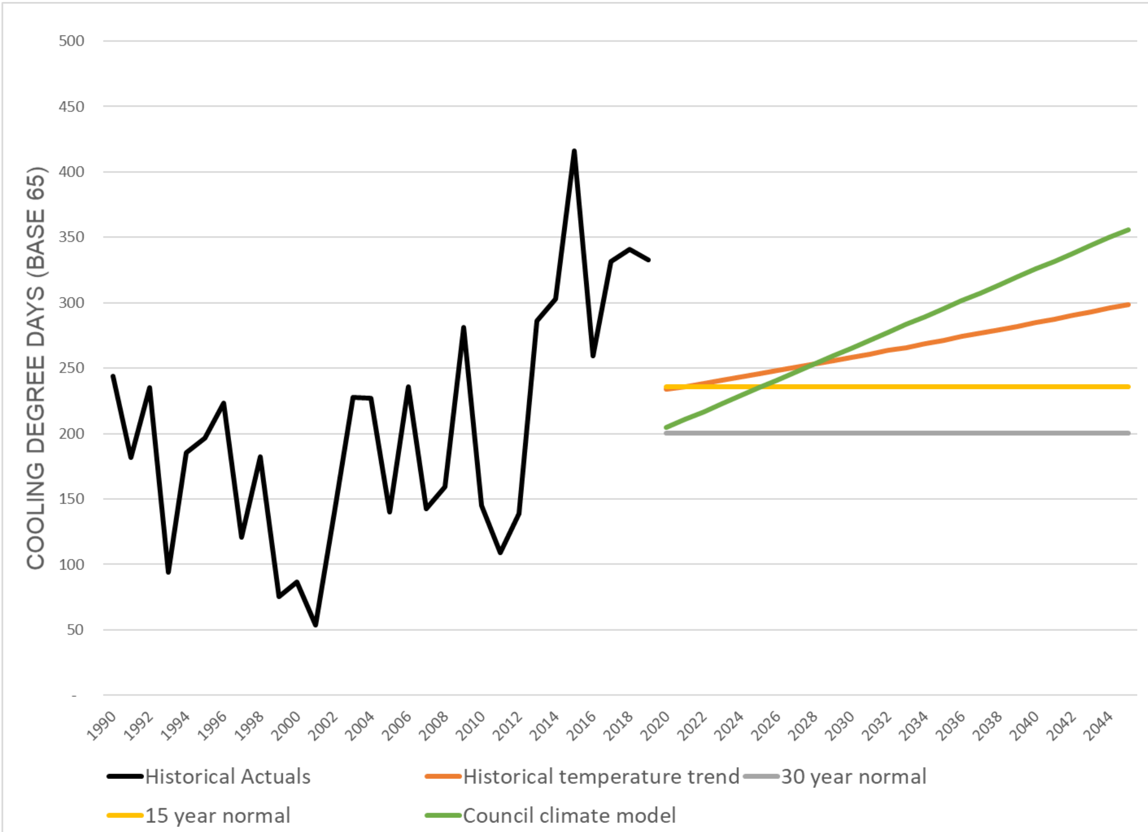


Figure 6-31: Annual Cooling Degree Days (Base 65) for the Three Temperature Sensitivity Options Compared to 30-year Normal HDDs Used in the Base Demand Forecast



Through the sensitivity prioritization process, stakeholders selected temperature sensitivity Option 3, which is based on the Northwest Power and Conservation Council climate model that assumes 0.9 degrees Fahrenheit warming per decade. Figures 6-32 and 6-33 compare the IRP base electric and natural gas energy demand forecasts with the forecasts that result from using this future temperature assumption.

With climate change, average temperatures are increasing over time. However, extreme weather events, both hot and cold, may still occur. Therefore, PSE did not change the peak temperature assumptions for this analysis, and therefore the peak demand did not change with this analysis.

In addition to the electric and gas energy demand forecasts, the electric RA model was run for this temperature sensitivity. The RA model examines a number of possible future conditions, including temperatures. The base RA model uses 88 historic temperature years: to create a wider range of possible future temperatures, PSE used all three of the NWPCC models, which mirrors the range of temperatures in NWPCC's RA analysis.

To create the RA model inputs temperatures from all three NWPCC models were used (CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA). Weather from the future decade in which the RA scenario takes place was used; that is, weather from 2020 through 2029 was used for the 2027 to 2028 RA model run, while weather from 2030 to 2039 was used for the 2031 to 2032 RA model run. The 10 years of weather from the three models was repeated almost three times and coupled with 88 economic and demographic draws to create 88 future hourly loads for the RA model.

Figure 6-32: Base Electric Energy Demand Forecast before Additional DSR Compared to Temperature Sensitivity Demand Forecast (aMW)

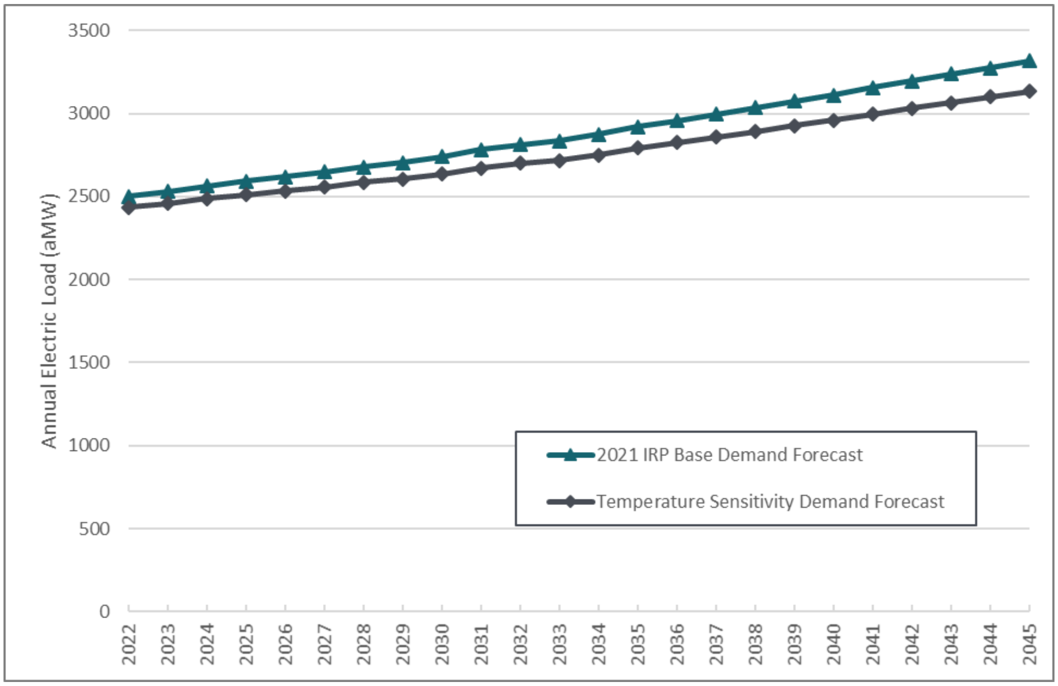
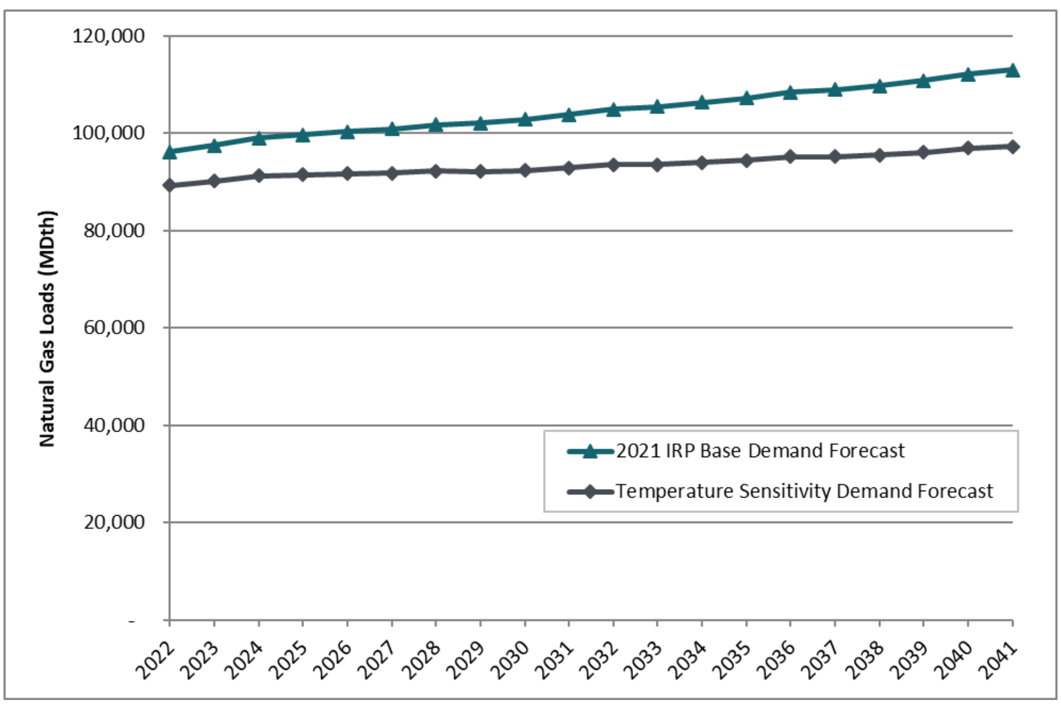


Figure 6-33: Base Natural Gas Energy Demand Forecast before Additional DSR Compared to Temperature Sensitivity Demand Forecast, without Transport Load (MDth)



Updates to Inputs and Equations

Updates to the demand forecast inputs and equations made since the 2019 IRP Process are summarized below.

POPULATION FORECAST. In previous IRPs, PSE has used Moody's forecast of U.S. population along with the economic and demographic model to forecast population in the electric and natural gas service areas. This has been under-forecasting population growth in the Puget Sound Area. In the 2021 IRP, population forecast is built up from county population forecasts that the Washington Employment Security Department (WA ESD) publishes. This better aligns the electric and natural gas forecasts of residential customers with population growth. Therefore, as population growth slows in the later part of the forecast period, the residential customer counts also slow.

ELECTRIC COMMERCIAL AND INDUSTRIAL CUSTOMER CLASSES. To better model the different segments of the electric commercial and industrial classes, the classes were broken out into smaller segments, including small/medium, large, high voltage and commercial lighting. Customer counts and use per customer were modeled for each segment individually, then added up to create the total customer counts and energy demand for each class.

SUMMER PEAK MODELING. The electric peak model was updated to include an index of air conditioning (AC) saturation in lieu of a linear trend as a proxy of past and future AC adoption. The AC index is created by using PSE's historical Residential Characteristics Survey (RCS) data points and calibrating to the U.S. Energy Information Administration (EIA) trend (West Region). The model driver was adopted to better track the non-linear nature of historical and future AC adoption.

MODELING SOFTWARE UPDATE. PSE transferred the demand forecast model from the Eviews application to energy forecasting software developed by Itron. The transition to Itron software enables PSE to manage the forecast input and output data in a database format (rather than separate Excel spreadsheets) and is modular in nature, organizing the forecasting steps in a consistent fashion across models. The modeling approach and methodology has not materially changed with this transition.

5. KEY ASSUMPTIONS

To develop PSE's demand forecasts, assumptions must be made about economic growth, energy prices, weather and loss factors, including certain system-specific conditions. These and other assumptions are described below.

Economic Growth

Economic activity has a significant effect on long-term energy demand. While the energy component of the national GDP has been declining over time, energy is still an essential input into various residential end uses such as space heating/cooling, water heating, lighting, cooking, dishwashing/clothes washing, electric vehicles and various other electric plug loads. The growth in residential building stock therefore directly impacts the demand for energy over time. Commercial and industrial sectors also use energy for space heating and cooling, water heating, lighting and for various plug loads. Energy is also an important input into many industrial production processes. Economic activities in the commercial and industrial sectors are therefore important indicators for the overall trends in energy consumption.

National Economic Outlook

Because the Puget Sound region is a major commercial and manufacturing center with strong links to the national economy, the IRP forecast begins with assumptions about what is happening in the broader U.S. economy. PSE relies on Moody's Analytics U.S. Macroeconomic Forecast, a long-term forecast of the U.S. economy for economic growth rates. The May 2020 Moody's forecast was used for this IRP.

The Moody's forecast calls for:

- A drop in employment and a sharp rise in unemployment in the second quarter of 2020 due to the COVID-19 pandemic. Unemployment stays above 6 percent until the first quarter of 2022, and is above 5 percent until the first quarter of 2023.
- After 2023 Moody's predicts the economy grows modestly as the U.S. population growth rate slows in the long term.
- U.S. GDP to continue to grow over the forecast period with 2.2 percent average annual growth from 2022 to 2045. This growth rate is higher compared to the Moody's forecast used in the 2019 IRP Process, which projected 2.0 percent average annual growth, but some of this growth is from the projected recovery from COVID-19.

- Average annual population growth of 0.4 percent for 2022-2045. This is down from the 0.6 percent growth rate Moody's forecast in the 2019 IRP Process for 2020-2039. However, this IRP did not use Moody's population projections because PSE's regional projections based on Moody's U.S. forecasts were consistently under-forecasting population growth in the electric and natural gas service areas. Instead, PSE used the Washington State Employment Security Department (WA ESD) population projections by county for the electric and natural gas service areas.

Moody's identified possible risks that could affect the accuracy of this forecast:[5]

- The Moody's forecast assumes that COVID-19 infections peak in May 2020 and begin to abate in July 2020. There is a downside risk if additional outbreaks occur, which are possible until a vaccine is widely available.
- Re-imposition of social distancing and forced business closures could derail any recovery that the economy has made.
- Moody's assumes that government and lawmakers provide monetary and fiscal responses to the pandemic to stabilize financial markets. The timing and size of this response is critical for determining the shape of the recovery.
- Changes to the economies of other global powers could affect the U.S. economy, especially as the demand for goods and services changes with the pandemic.
- Retaliations to U.S. tariffs could cause lower U.S. and global growth.

Regional Economic Outlook

PSE prepares regional economic and demographic forecasts using econometric models based on historical economic data for the counties in PSE's service area and the macroeconomic forecasts for the United States.

PSE's service area covers more than 6,000 square miles, stretching from south Puget Sound to the Canadian border, and from central Washington's Kittitas Valley west to the Kitsap Peninsula. PSE serves more than 1.1 million electric customers and more than 840,000 natural gas customers in 10 counties.

Within PSE's service area, demand growth is uneven. Most of the economic growth is driven by growth in the high tech, information technology or retail (including online retail) sectors; supporting industries like leisure and hospitality employment are also growing. Job growth is concentrated in King County, which accounts for half or more of the system's electric and

5 / Moody's Analytics (2020, May) Forecast Risks. Precis U.S. Macro. Volume 25 Number 2.

natural gas sales demand today. Other counties are growing, but typically more slowly, and have added fewer jobs.

Electric Scenario Outlooks: Base, High and Low

BASE SCENARIO OUTLOOK. The following forecast assumptions are used in the 2021 IRP Base Electric Demand Forecast scenario.

- Employment is expected to grow at an average annual rate of 0.6 percent between 2022 and 2045, which is the same as the annual growth rate forecasted in the 2019 IRP Process.
- Local employers are expected to create about 310,000 total jobs between 2022 and 2045, mainly driven by growth in the commercial sector, compared to about 257,000 jobs forecasted in the 2019 IRP Process.
- Manufacturing employment is expected to decline by 0.1 percent annually on average between 2022 and 2045 due to the outsourcing of manufacturing processes to lower wage or less expensive states or countries, and due to the continuing trend of capital investments that create productivity increases.
- An inflow of 975,000 new residents (by birth or migration) is expected to increase the local area population to 5.3 million by 2045, for an average annual growth rate of 0.9 percent. This growth rate is not constant over time, and the population growth rate is expected to be higher in the near term and lower in the long term. However, on average, this growth rate is higher than the 2019 IRP Process forecast, which projected an average annual population growth of 0.6 percent that would have resulted in 4.6 million electric service area residents by 2039. The 2021 forecast has a different growth rate because the population forecast in this IRP is based on the WA ESD forecast of population instead of Moody's population forecast.

Local economists at Western Washington University have identified possible risks to the regional economy:[6, 5]

- It is unknown when the COVID-19 vaccine will achieve widespread immunity.
- Employers are taking on debt to make ends meet as their customers are spending less.
- Unforeseen layoffs from struggling businesses could slow economic recovery.
- Political and social unrest will have unknown effects on the economy.
- Lingering U.S.-China tension could affect the economy.

HIGH SCENARIO OUTLOOK. For the Electric High Demand Forecast scenario, population grows by 1.1 percent annually from 2022 to 2045, and employment grows by 0.8 percent per year during that period.

LOW SCENARIO OUTLOOK. For the Electric Low Demand Forecast scenario, population grows by 0.7 percent annually from 2022 to 2045. Employment grows 0.3 percent annually from 2022 to 2045.

The Base, High and Low population and employment forecasts for PSE's electric service area are compared in Figures 6-34 and 6-35.

5 / Western Washington University Center of Economic and Business Research (2020, June) Regional Outlook. Puget Sound Economic Forecaster. Volume 28 Issue 2.

6 / Western Washington University Center of Economic and Business Research (2020, March) Regional Outlook. Puget Sound Economic Forecaster. Volume 28 Issue 1.

Figure 6-34: Population Growth, Electric Service Counties

2021 IRP POPULATION GROWTH, ELECTRIC SERVICE COUNTIES (1,000s)							
Scenario	2022	2025	2030	2035	2040	2045	AARG 2022-2045
2021 IRP Base Demand Forecast	4,334	4,482	4,715	4,936	5,134	5,310	0.9%
2021 IRP High Demand Forecast	4,398	4,609	4,902	5,158	5,398	5,609	1.1%
2021 IRP Low Demand Forecast	4,267	4,363	4,536	4,723	4,869	4,989	0.7%

Figure 6-35: Employment Growth, Electric Service Counties

2021 IRP EMPLOYMENT GROWTH, ELECTRIC SERVICE COUNTIES (1,000s)							
Scenario	2022	2025	2030	2035	2040	2045	AARG 2022-2045
2021 IRP Base Demand Forecast	2,172	2,268	2,327	2,385	2,436	2,482	0.6%
2021 IRP High Demand Forecast	2,365	2,488	2,562	2,669	2,744	2,814	0.8%
2021 IRP Low Demand Forecast	1,996	2,047	2,088	2,103	2,145	2,159	0.3%

Natural Gas Scenario Outlooks: Base, High and Low

BASE SCENARIO OUTLOOK. In the Base Natural Gas Demand Forecast scenario, population grows by 1.0 percent annually from 4.5 million people in 2022 to 5.45 million people by 2041. Employment is expected to grow by 1.2 percent annually from 2022 to 2041.

HIGH SCENARIO OUTLOOK. For the High Natural Gas Demand Forecast scenario, population grows by 1.2 percent annually from 2022 to 2041, and employment grows by 2.1 percent per year during that period.

LOW SCENARIO OUTLOOK. For the Low Natural Gas Demand Forecast scenario, population grows 0.8 percent annually from 2022 to 2041, and employment grows 0.2 percent annually.

The Base, High and Low population and employment forecasts for PSE's natural gas sales service area are compared in Figures 6-36 and 6-37.

Figure 6-36: Population Growth, Natural Gas Service Counties

2021 IRP POPULATION GROWTH, NATURAL GAS SERVICE COUNTIES (1,000s)						
Scenario	2022	2025	2030	2035	2041	AARG 2022-2041
2021 IRP Base Demand Forecast	4,542	4,703	4,953	5,197	5,452	1.0%
2021 IRP High Demand Forecast	4,619	4,842	5,159	5,437	5,766	1.2%
2021 IRP Low Demand Forecast	4,461	4,575	4,769	4,955	5,146	0.8%

Figure 6-37: Employment Growth, Natural Gas Service Counties

2021 IRP EMPLOYMENT GROWTH, NATURAL GAS SERVICE COUNTIES (1,000s)						
Scenario	2022	2025	2030	2035	2041	AARG 2022-2041
2021 IRP Base Demand Forecast	2,225	2,368	2,497	2,628	2,780	1.2%
2021 IRP High Demand Forecast	2,478	2,748	3,043	3,257	3,655	2.1%
2021 IRP Low Demand Forecast	1,975	1,987	1,989	2,022	2,042	0.2%

Other Assumptions

Weather

For the IRP Base Demand scenario, the energy demand forecast is based on normal weather, defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the 30 years ending in 2019. The 2021 IRP forecast methodology, as described in this chapter and Appendix F, Demand Forecasting Models, employs various thresholds of heating and cooling degree days, consistent with industry practices. Employing monthly degree days helps estimate the amount of weather-sensitive demand in the service area. PSE rolls forward the 30-year period employed in each IRP to capture recent climate conditions. To create the High and Low Demand Forecasts historic monthly temperature observations are used to project a distribution of possible future temperature-sensitive demand, thereby modeling a wider range of warmer and colder conditions than the Base Demand Forecast.

In this IRP, PSE is including a temperature sensitivity that explores how changing heating and cooling degree days could affect loads in the future as the climate warms. This sensitivity is described in detail in Chapter 5, Key Analytical Assumptions.

Additionally, PSE is following and participating in the regional efforts of the Northwest Power and Conservation Council to include climate change in its planning process. These efforts include both forecasting future temperatures as well as considering secondary effects of climate change on population and economic growth. Future IRPs will incorporate climate change impacts as regionally accepted information becomes available.

COVID-19 Adjustments

In early March 2020, the COVID-19 pandemic reached the Puget Sound region in earnest. The governor issued a "Stay Home, Stay Healthy" order on March 23 that had immediate impacts on the local economy. To account for the pandemic's effects on the economy, customer counts and demand, PSE incorporated the May 2020 Moody's Analytics economic forecast, the most current Moody's forecast at the time the IRP forecast was developed. Moody's forecast included the following economic and epidemiological assumptions about the severity of the disease and its effects on the economy: that new infections would abate in July 2020 without a second wave of infections; that unemployment would spike in 2Q 2020; and that the recovery from the resulting recession would last through 2023, when unemployment would return to around 5 percent.

The typical relationship between historic economic assumptions and the forecast was not able to capture all of the immediate impacts to the demand forecast for year 2020, so PSE made additional assumptions and adjustments to reflect the impacts of COVID-19 by tracking the observed effects on each customer class. For the commercial class, PSE assessed the potential impacts by building type, since some sectors of the economy were hit harder than others. Adjustments from these additional analyses were then aligned with the epidemiological assumptions made by Moody's May 2020 forecast.

After 2020, no additional adjustments were made above and beyond the effects of the economic forecast that was incorporated into the demand forecast using the macroeconomic variables. The result was a slow recovery over the following few years and a recovered economy by 2024, with lingering effects from the recession persisting thorough out the remainder of the forecast.

PSE performed stochastic simulations that varied the economic forecast around this base forecast. These included simulations with better and worse economic outcomes that were the basis for the high and low forecasts. Since the IRP determines the resource need starting in 2022, the high and low forecasts show alternative ways the pandemic could resolve in the future.

Loss Factors

The electric loss factor is 6.8 percent, compared to 7.1 percent in the 2019 IRP Process. The gas loss factor in this IRP is 0.2 percent, which is the same as the loss factor in the 2019 IRP Process. The loss factors assumed in the demand forecast are system-wide average losses during normal operations for the past 2 to 3 years.

Block Load Additions

Beyond typical economic change, the demand forecast also takes into account known major demand additions and deletions that would not be accounted for though typical load growth in the forecast. The majority of these additions are from major infrastructure projects. These additions to the forecast are called block loads and they use information provided by PSE's system planners. The adjustments to non-transport customers add 91.1 MW of connected demand by 2025 for the electric system as a whole. These block loads are included in the commercial class, and King County has the majority of the additions.

The natural gas forecast includes block loads of 0.1 MDth per day which are included in the industrial class.

Schedule Switching

In addition to block loads, PSE accounts for customers that switch between rate schedules. Customers that purchase their own electricity or natural gas are called transportation customers and they rely on PSE for distribution services. Because PSE is not responsible for acquiring supply resources for electric or natural gas transportation customers, in the IRP they are removed from the forecast before supply-side resource need is determined.

Interruptible Loads

PSE has 152 electric interruptible customers; six of these are commercial and industrial customers and 146 are schools. The school contracts limit the time of day when energy can be curtailed. The other customers represent 14 MW of coincident peak demand. In this IRP, PSE did not count the 14 MW of DR potential, but this will be included in future modeling.

For a number of natural gas customers, all or part of their volume is interruptible volume. The curtailment of interruptible gas volumes was assumed when forecasting peak natural gas demand.

Electric Vehicles

An electric vehicle (EV) forecast was created for PSE by Guidehouse in early 2020. The forecast assumes 60,000 customer-owned light duty EVs on the road in PSE's service area in 2022, increasing to 705,000 EVs in 2045. Annual energy sales from new electric vehicles total 83,000 MWh in 2022 and 1,960,000 MWh in 2045. Initially, 81 percent of this charging is assumed to occur on residential accounts, while the remaining 19 percent is assumed to occur through commercial accounts. During the forecast period this percentage changes as charging at commercial locations becomes more widely available, resulting in 56 percent charging on residential accounts and 44 percent charging on commercial accounts in 2045. Electric vehicles are an emerging technology, thus PSE anticipates this forecast will be revised on an ongoing basis in the future. The additional demand by electric vehicles grows to an 8 percent share of total peak demand by 2045, before including cost-effective DSR identified in the 2021 IRP. Figure 6-38 below shows the December evening peak demand and annual average energy demand from new electric vehicles. Figure 6-39 shows the forecast of electric vehicles as a percent of all vehicles purchased in the PSE service territory.

Figure 6-38: Electric Vehicle Peak Demand and Average Energy Demand from New Vehicles (aMW, MW)

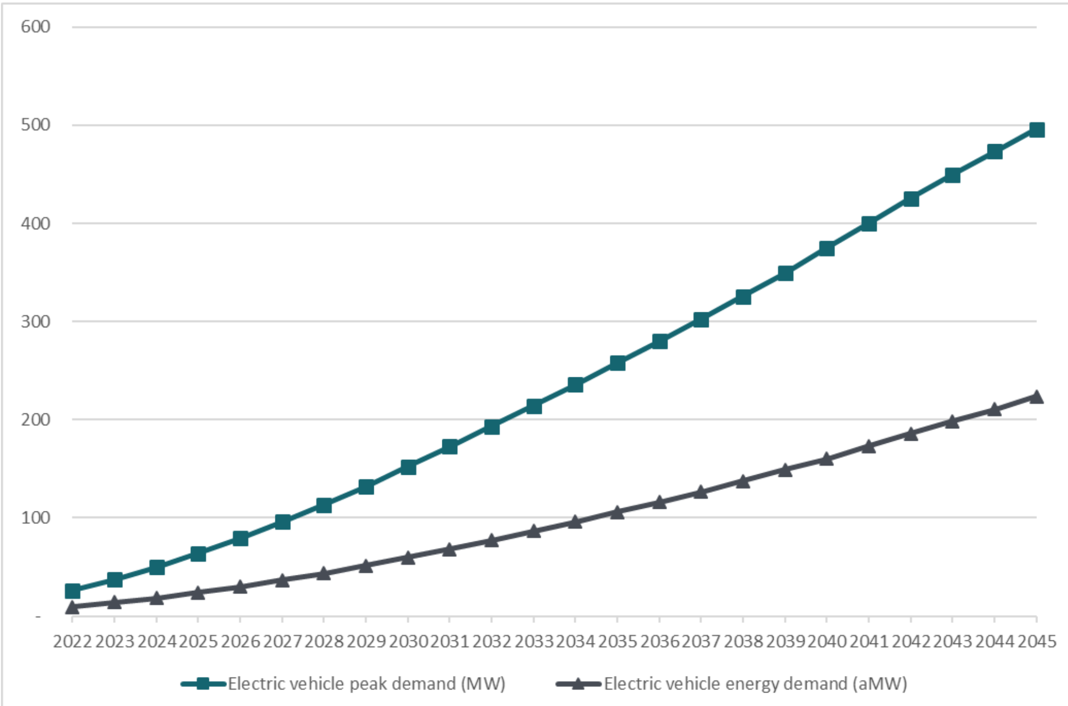
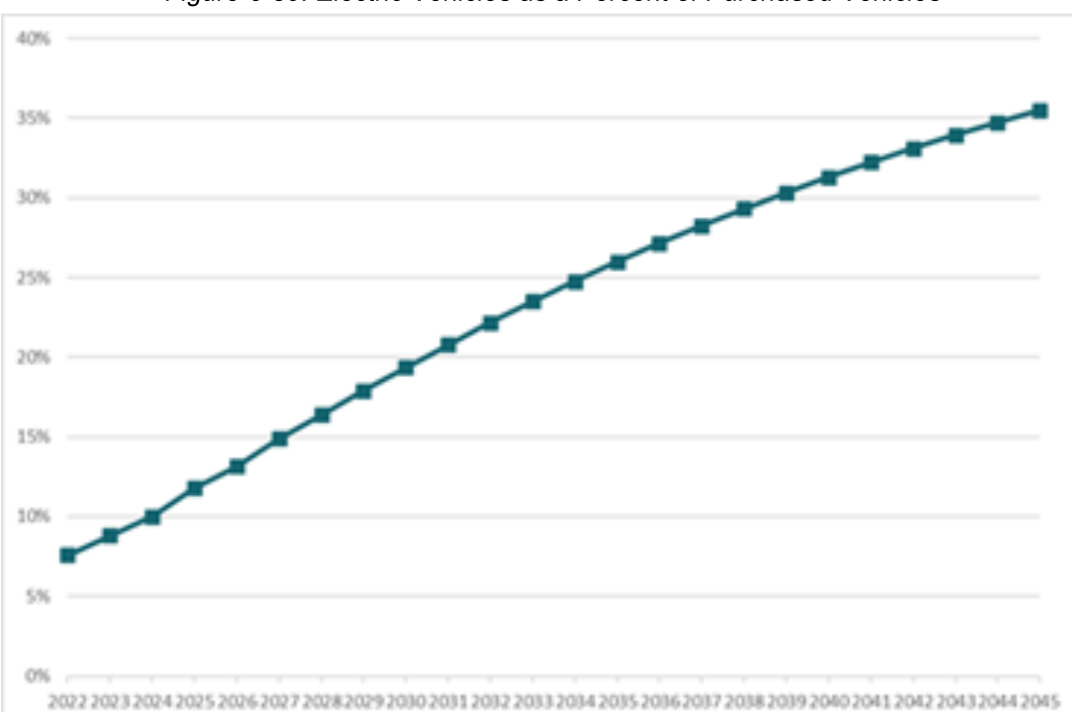


Figure 6-39: Electric Vehicles as a Percent of Purchased Vehicles



Compressed Natural Gas Vehicles

Compressed natural gas (CNG) vehicles were added to the 2021 IRP Natural Gas Base Demand Forecast. CNG vehicles include marine vessels, buses, light-duty vehicles, medium-duty vehicles and heavy-duty vehicles. In 2022, this adds 365 MDth to the forecast. This demand is expected to grow at an average annual rate of 3.5 percent, based on the Annual Energy Outlook 2019 published by the U.S. Department of Energy.

Retail Rates

Retail energy prices – what customers pay for energy – are included as explanatory variables in the demand forecast models, because in the long run, they affect customer choices about the efficiency level of newly acquired appliances, how those appliances are used, and the type of energy source used to power them. The energy price forecasts draw on information obtained from internal and external sources.

Distributed Generation

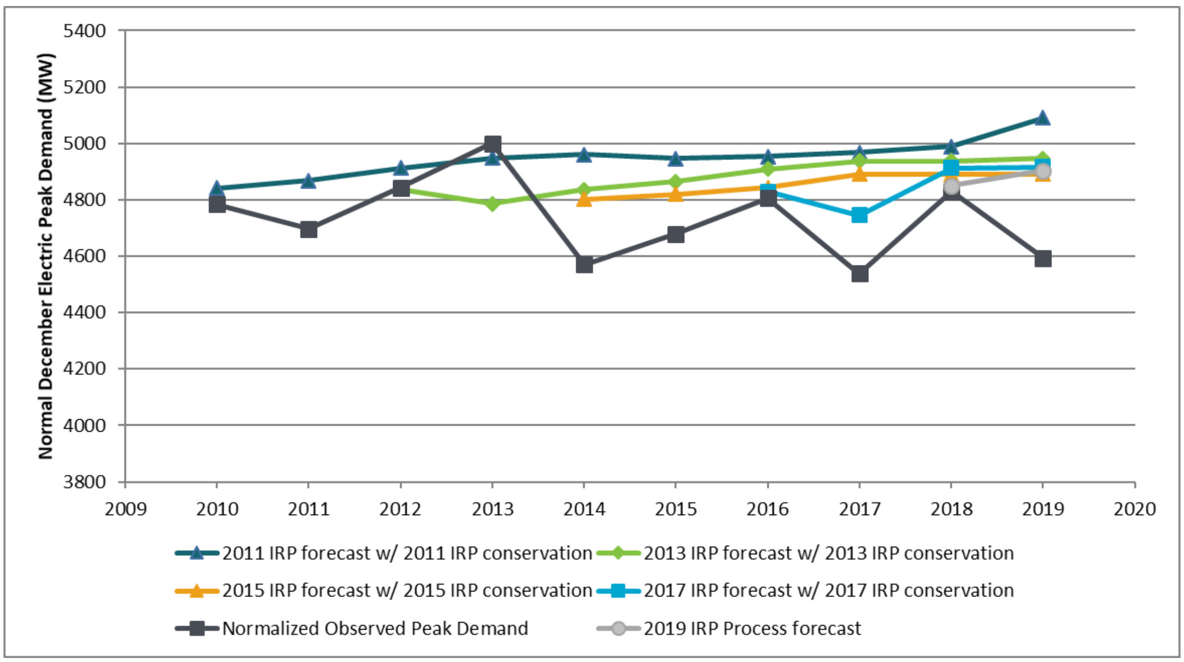
Distributed generation, including customer-level generation via solar panels, was not included in the demand forecast; this energy production is captured in the IRP modeling process as a demand-side resource. A description is included in the Appendix E, Conservation Potential Assessment and Demand Response Assessment.

6. RETROSPECTIVE OF PREVIOUS DEMAND FORECASTS

IRP Peak Demand Forecasts Compared to Actual Peaks

Figure 6-40 compares the 2011, 2013, 2015, 2017 and 2019 IRP Process electric Base Scenario peak demand forecasts after DSR with normalized[7] actual observations. The normalized actual observations account for peak hourly temperature, monthly HDDs, and the day of week and time of day the actual peak was observed. The percent difference of normalized actual values compared to each IRP forecast is presented for each year in Figure 6-41.

Figure 6-40: Observed Normalized Electric December Peak Demand Compared to Previous IRP forecasts



7 / *Given that the forecasts are for peaks at a design temperature, observed actual peaks are adjusted to reflect what would have been the peak if the design peak temperatures had been achieved.*

Figure 6-41: Observed Electric Peak Demand and Difference from Previous IRP Forecasts

ELECTRIC DECEMBER PEAK DEMAND % DIFFERENCE OF IRP FORECAST VERSUS WEATHER NORMALIZED ACTUAL OBSERVATION					
Year	2011 IRP	2013 IRP	2015 IRP	2017 IRP	2019 IRP Process
2010	1.2%				
2011	3.6%				
2012	1.5%	-0.1%			
2013	-1.0%	-4.3%			
2014	8.5%	5.8%	5.1%		
2015	5.7%	4.0%	3.0%		
2016	3.1%	2.1%	0.8%	0.5%	
2017	9.5%	8.8%	7.8%	4.6%	
2018	3.3%	2.3%	1.2%	1.7%	0.5%
2019	10.8%	7.7%	6.5%	7.1%	6.8%

Similarly, weather normalized actual natural gas peak demand is compared to the natural gas peak forecasts after conservation from the 2011, 2013, 2015, 2017 IRPs and the 2019 IRP Process in Figures 6-42 and 6-43.

Figure 6-42: Observed Weather Normalized Natural Gas Peak Demand Compared to Previous IRP Forecasts of Natural Gas Peak Demand

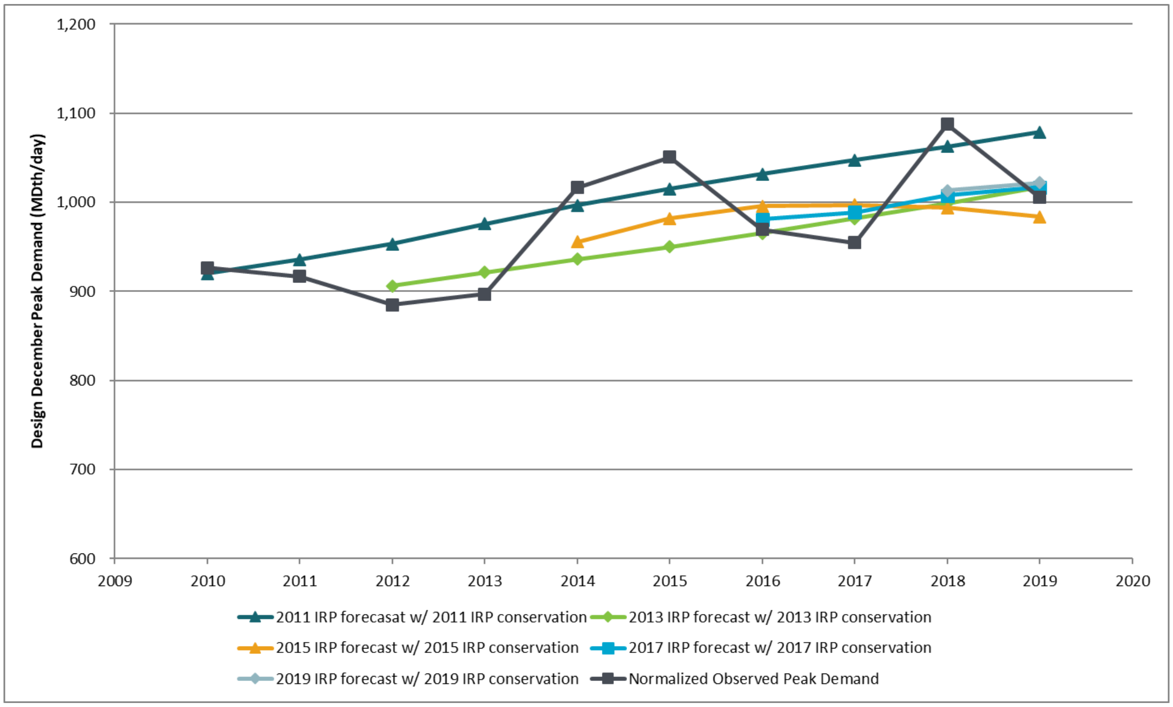


Figure 6-43: Observed Natural Gas Peak Demand and Difference from Previous IRP Forecasts

NATURAL GAS DECEMBER PEAK DEMAND % DIFFERENCE OF IRP FORECAST VERSUS WEATHER NORMALIZED ACTUAL OBSERVATION					
Year	**2011 IRP**	**2013 IRP**	**2015 IRP**	**2017 IRP**	**2019 IRP Process**
2010	-0.7%				
2011	2.0%				
2012	7.8%	2.4%			
2013	8.8%	2.7%			
2014	-2.0%	-7.9%	-5.6%		
2015	-3.4%	-9.6%	-6.1%		
2016	6.4%	-0.4%	3.2%	1.2%	
2017	9.7%	2.8%	5.0%	3.6%	
2018	-2.3%	-8.2%	-8.2%	-7.4%	-6.9%
2019	7.3%	1.1%	-1.7%	1.1%	1.6%

Reasons for Forecast Variance

As explained throughout this chapter, the IRP peak demand forecasts are based on forecasts of key demand drivers that include expected economic and demographic behavior, conservation, customer usage and weather. When these forecasts diverge from observed actual behavior, so does the IRP forecast. These differences are explained below.

Economic and Demographic Forecasts

Economic and demographic factors are key drivers for the IRP peak demand forecast. After the 2008 recession hit the U.S. economy, many economists, including Moody's Analytics, assumed that the economy would recover sooner than it did. A full recovery was pushed out with each successive forecast as the U.S. economy failed to bounce back to its previous state year after year. The charts below compare the Moody's forecasts of U.S. housing starts and population growth incorporated in the 2011 IRP through the 2019 IRP Process with actual U.S. housing starts and population growth. Moody's too-optimistic forecasts of housing starts and population growth during the recession led to over-estimated forecasts of customer counts. Since the 2019 IRP Process, forecasts of housing starts are no longer used as a driver in the demand forecast; instead, forecasts of population based on WA ESD data are now used to forecast population in PSE's service territories. The Moody's forecast of housing starts and population from May 2020 are included in the two charts below for comparison

Additionally, while the Moody's forecast used in the 2019 IRP Process did predict a softening of the economy in 2020, it did not forecast the magnitude of the effects from the COVID-19 pandemic. Therefore, Moody's forecasts used prior to the 2021 IRP have likely over-estimated economic growth in 2020 and the following few years. It is likely that the full extent of the pandemic's repercussions on the economy and energy demand will not be known during this IRP cycle.

Figure 6-44: Moody's Forecasts of U.S. Housing Starts Compared to Actual Housing Starts

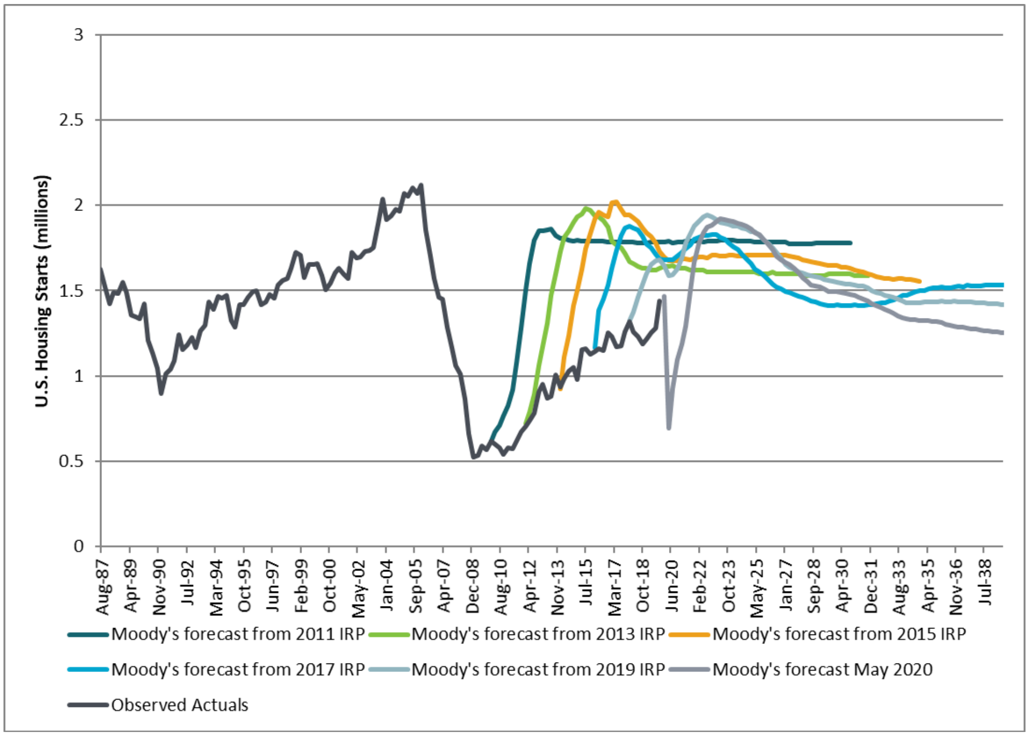
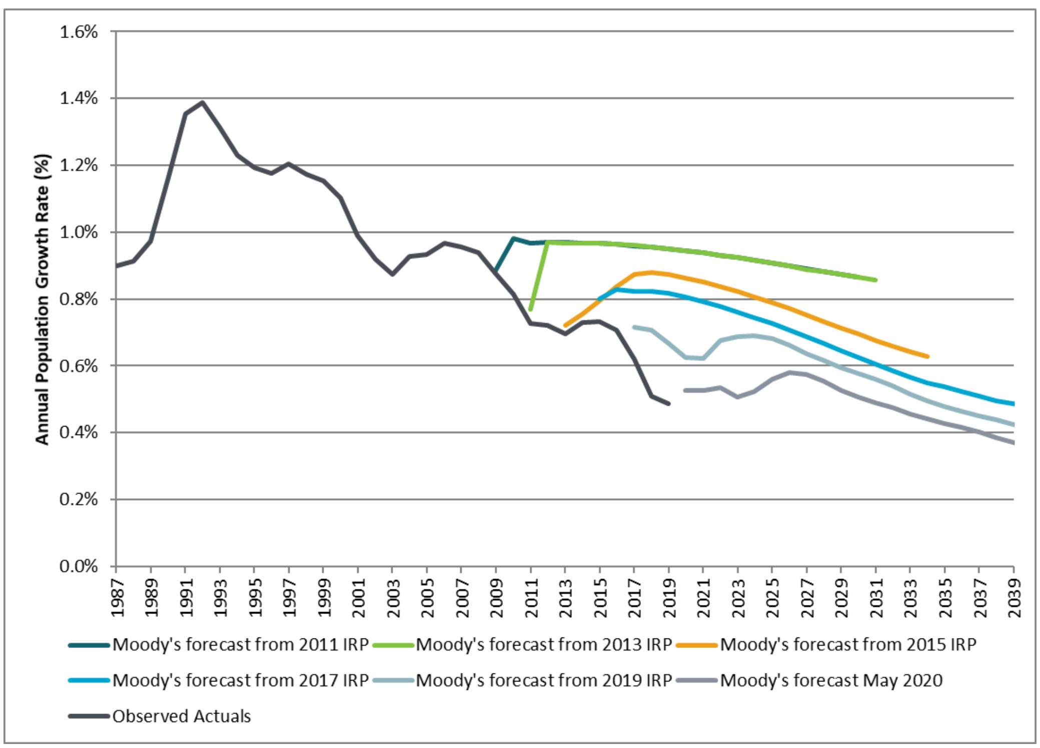


Figure 6-45: Moody's Forecasts of U.S. Population Growth Compared to Actual Population Growth



Conservation and Customer Usage

The comparison in Figures 6-40 and 6-42 of weather normalized peak observations to the IRP peak demand forecasts after conservation assumes that the forecasted conservation will be implemented. However, consumers can adopt energy efficient technologies that are above and beyond what is incentivized by utility-sponsored conservation programs and building codes and standards. This leads to more actual conservation taking place than forecasted. Additionally, conservation programs can change over time. Programs that were not cost effective in the past, and therefore not included in the optimal bundle, can be chosen in a later IRP as cost effective. This can make an older forecast out of date, making the forecast of conservation too low and therefore the load forecast after conservation too high.

Also, due to the Global Settlement from the 2013 General Rate Case (GRC) PSE and the 2017 GRC, PSE decisions accelerate electric and natural gas conservation, respectively, by 5 percent each year. This is additional conservation that is not taken into account in this comparison of IRP forecasts with normalized actuals.

Normal Weather Changes

Normal weather assumptions change from forecast to forecast. For each IRP, the normal weather assumption is updated by rolling off two older years of data and incorporating two new years of weather data into the 30-year average. Over time, normal heating degree days have been declining and normal cooling degree days have been increasing. As temperatures change over time, the forecast of demand with normal weather changes.

Additionally, over time our customers' weather sensitivity has been changing. As energy efficiency measures have been implemented, customers use less energy at a given temperature, including at peak temperatures. More recent forecasts reflect this change in weather sensitivity better than older forecasts.

Non-design Conditions during Observed Peaks

Peak values are weather normalized using the peak forecasting model. This model uses peak values from each month to create a relationship between peak demand, monthly demand and peak temperature. However, some of the observed December peaks shown above occurred on atypical days rather than typical days. For example, natural gas peaks in 2010, 2013, 2016, and 2017 fell on weekends. Natural gas peaks in 2010, 2012, and 2015 fell on New Year's Eve and the 2019 peak fell on Boxing Day (the day after Christmas). Additionally, in 2014, the electric peak fell on the Monday morning after Thanksgiving weekend, in 2015 it fell on New Year's Eve, and in 2019 it fell on the day after Christmas. Usage on these days is likely to be different than usage on a typical non-holiday weekday peak. Therefore, when these dates are weather normalized, they may not line up with the forecasted values since the usage patterns are atypical.

Service Area Changes

In March 2013, Jefferson County left the PSE service area. Jefferson County usage was included in the electric peak demand forecast in the 2011 IRP, therefore, when comparing that forecast to today's actuals, those forecasts would be expected to be higher than the actual peak demand.