DEMAND FORECASTS

CHAPTER SIX

PUGET SOUND ENERGY

Contents

1. Introduction 1
   - 1.1. Impacts of Demand-side Resources 2
2. Climate Change 3
   - 2.1. Priorities First 3
   - 2.2. Determine Climate Change Normal Temperatures 4
   - 2.3. Normal Temperature for Energy Demand Forecast 5
   - 2.4. Normal Temperature for Peak Demand Forecast 7
3. Electric Demand Forecast 9
   - 3.1. Electric Energy Demand 10
   - 3.2. Electric Peak Demand 11
   - 3.3. Impacts of Demand-side Resources 14
   - 3.4. Details of the Electric Forecast 18
4. Methodology 20
   - 4.1. Forecasting Process 20
   - 4.2. Stochastic Scenarios 22
   - 4.3. Resource Adequacy Model Inputs 26
   - 4.4. Updates to Inputs and Equations 27
5. Key Assumptions 28
   - 5.1. Economic Growth 28
   - 5.2. Weather 30
   - 5.3. Electric Vehicles 30
   - 5.4. COVID-19 Impacts 34
   - 5.5. Loss Factors 34
   - 5.6. Block Load Additions 35
   - 5.7. Schedule Switching 35
   - 5.8. Interruptible Demand 35
   - 5.9. Retail Rates 35
   - 5.10. Distributed Generation 35
6. Previous Demand Forecasts 35
   - 6.1. IRP Peak Demand Forecasts Compared to Actual Peaks 36

1. Introduction

The demand forecasts Puget Sound Energy (PSE) developed for this 2023 Electric Progress Report (2023 Electric Report) calculate the amount of electricity required to meet customers' needs over the more than 20-year study period, 2024–2045. These forecasts focus on two dimensions of demand: energy demand and peak demand.

- Energy demand is the total electricity needed to meet customer needs yearly (megawatt hours [MWh], or average megawatts [aMW]).
- Peak demand is the single highest hour of electricity demanded by customers each season, winter or summer (MW).

Puget Sound Energy incorporated crucial climate change data into the demand forecast for the first time in this report. We heard from interested parties that climate change is important because it affects future demand and needs, and we agree. We included climate change in the base demand forecast and in other analyses such as the stochastic scenarios.

Climate change already affects how our electricity customers use energy, and we expect that impact will increase. We expect summer and winter average and peak temperatures to get warmer. The energy and peak demand forecasts now incorporate climate change temperature effects. We also incorporated climate change in the resource adequacy (RA) analysis, the stochastic scenarios, and the conservation potential assessment (CPA). Including climate change in energy planning is crucial since it affects our customers.

Overall, we expect electric energy demand, before additional demand-side resources (DSR) identified in the 2023 Electric Report's base demand forecast, to grow at an average annual growth rate (AARG) of 1.8 percent from 2024 to 2045. This growth rate increased our forecast from 2,551 aMW in 2024 to 3,699 aMW in 2045, faster than the 1.2 average annual energy growth rate forecasted in the 2021 Integrated Resource Plan (IRP).

We expect base peak demand before additional DSR to increase at a 1.7 percent annual growth rate, from 4,753 MW in 2024 to 6,717 MW in 2045. This rate is also faster than the 1.2 percent average annual growth rate forecasted in the 2021 IRP and resulted in higher total peak demand at the end of the study period. New customers and electric vehicles are the principal drivers of the growth. Demand from customers using electric vehicles increases residential and commercial use per customer across the entire forecast period.

The 2023 Electric Report base demand forecasts also include the effects of climate change. Warming temperatures decrease energy usage in the winter and increase it in the summer. That phenomenon increases both the winter and summer normal peak temperatures; therefore, the peak forecast includes demand decreases in the winter and increases in the summer.

Table 6.1: Drivers Included and Not Included in the Base Demand Forecasts

Drivers	Demand Forecast Before Additional DSR	Demand Forecast After Additional DSR
Climate change temperatures	Yes	Yes
PSE energy efficiency programs for 2022–2023	Yes	Yes
Codes and standards effects through 2023	Yes	Yes
Demand-side solar installed through 2023	Yes	Yes
PSE energy efficiency programs for 2024 and beyond	No	Yes
Codes and standards for 2024 and beyond (Including Bellingham natural gas ban)	No	Yes
Demand-side solar installed in 2024 and beyond	No	Yes
Electric vehicle legislation: Zero Emission Vehicle (2020) and Clean Fuel Standard (2021)	Yes	Yes
Electric vehicle legislation: Clean Cars 2030 goal (2022)	No	No
Effects of the Climate Commitment Act or additional electrification	No	No
Inflation Reduction Act effects from the investment tax credit (ITC) on behind-the-meter solar	No	Yes
Inflation Reduction Act effects for DSR projects other than solar	No	No

We prepared stochastic draws in addition to the base demand forecast to model a range of potential economic conditions, weather conditions, and modeling variance in the 2023 Electric Report analysis. These draws included variations in temperature, economic and demographic drivers, electric vehicles, and demand model uncertainty. We also used modeled climate change temperatures to project a distribution of possible future temperature-sensitive demand, thereby modeling a more comprehensive range of warmer and colder conditions than the base demand forecast.

Demand and *load* are often used interchangeably in the energy industry, but they refer to different concepts. In this IRP demand refers to the energy needed to meet customers' needs during a calendar year, including losses, and load refers to demand plus the planning margin and operating reserves required to ensure the reliable and safe operation of the electric system.

1.1. Impacts of Demand-side Resources

When we applied forward projections of additional DSR savings, as shown in Table 6.2, we reduced demand significantly. However, it is necessary to start with forecasts that do not already include forward projections of DSR savings to identify the most cost-effective amount of DSR to include in the resource plan. Throughout this chapter, charts and tables labeled before additional DSR have only DSR measures implemented before the study period begins in 2024. Charts labeled after additional DSR include the cost-effective amount of DSR we identified in the 2023 Electric Report.

1.1.1. Demand Before Demand-side Resources

Why does PSE forecast demand before DSR? The demand forecast before DSR shows us the problem. What if no one acted to change how we use energy? That is not a future we anticipate. Demand-side resources like energy efficiency and demand management programs change energy use. We expect to continue incentivizing DSR. Federal, state, and local governments will continue changing energy codes and standards, and we expect consumers to continue putting solar panels on their roofs. But how much of this will occur, and how will it change the demand forecast? To answer this question, we assume no DSR and treat DSR as a resource in the modeling process. This methodology is industry standard and set forth by WAC 480-100-620[1] as part of the content of an integrated resource plan.

Table 6.2: Effect of Demand-side Resources on Demand Forecasts

2023 Electric Report Base Demand Forecast in 2045	Before Additional DSR	After Additional DSR
Electric Energy Demand (aMW)	3,699	2,949
Electric Peak Demand (MW)	6,717	5,867

2. Climate Change

This 2023 Electric Report marks the first time PSE incorporated climate change into the base energy and peak demand forecasts. Before this 2023 Electric Report, we used temperatures from the previous 30 years to model the expected normal temperature for the future. We then held this normal temperature constant for each future model year. This approach to forecasting is a common utility practice, but it does not recognize predicted climate change. This section provides a detailed description of our approach to developing a normal temperature assumption.

2.1. Priorities First

Puget Sound Energy heard and heeded the clear message from interested parties that climate change is a high priority, and we should incorporate its effects into our planning processes. It is essential to consider climate change in resource planning because PSE customers use electricity to heat in the winter and keep cool in the summer. Over time, we expect less overall heating demand and more cooling demand because of a general average warming trend. We used regional data recently developed by climate change scientists to calculate a normal temperature assumption that reflects climate change.

There are currently no industry standards or best practices for incorporating climate change into a demand forecast. The team at PSE is excited to include climate change in this report and participate in future refinements and the evolution of this methodology.

1 WAC 480-100-620

We are incorporating climate change into the demand forecast in several ways:

- Energy demand forecast
- Peak demand forecast
- Resource adequacy (RA) analysis
- Stochastic analysis

The climate projections used in the forecast were part of a recent study conducted by the River Management Joint Operating Committee (RMJOC). The RMJOC consists of the Bonneville Power Administration, the U.S. Army Corps of Engineers, and the U.S. Bureau of Reclamation. This committee worked with climate scientists to produce many downscaled climate and hydrologic models for the Northwest region as part of their long-term planning.[2] The RMJOC chose 19 downscaled models. Each model is on the representative concentration pathway (RCP) of 8.5. An RCP is a forecast of the amount of warming to the Earth. RCP 8.5 is a high yet common warming forecast used by climate scientists. It represents more warming than other common warming forecasts, such as RCP 4.5 or 6.0.

The Northwest Power and Conservation Council (NWPCC) chose three of these 19 models to work with: CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA. The NWPCC chose these three models because they reflect a wide range of temperatures and hydrologic conditions over time. We used the three climate model projections selected by the NWPCC.

2.2. Determine Climate Change Normal Temperatures

This 2023 Electric Report marks the first time PSE incorporated climate change in the demand forecast and other aspects of planning. Since there is no industry standard approach to integrating climate change, we had to establish how to incorporate this data into our forecasts. The following section explains how we approached the challenge and the questions we asked. We also presented these questions and the analysis results to interested parties on January 20, 2022, and asked them for feedback on our approach.

2.2.1. What is Normal and Why Do We Need It?

When PSE models demand, we study the relationship between historical demand and historical temperatures because the temperature significantly impacts demand. Then, to create a demand forecast, PSE must make assumptions about future temperatures to create a future demand forecast. We refer to the assumed future temperatures as normal temperatures. For energy forecasting, the average heating degree day (HDD) and/or cooling degree day (CDD) for a month expresses the new normal temperature. We used a one-in-two occurrence of a given temperature to forecast peak demand.

We wanted to achieve three goals when we created new normal temperatures:

1. Develop an objective temperature normal, which included deciding what data to use.

[2] River Joint Management Operating Committee (RMJOC): Bonneville Power Administration, United State Army Corps of Engineers, United Stats Bureau of Reclamation (2018). Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part 1:Hydroclimate Projections and Analyses.

2. Incorporate future temperature trends into the assumptions for the base demand forecasts. We provided a scenario in the 2021 IRP with climate change temperatures, but incorporated a more comprehensive approach in this 2023 Electric Report's base demand energy and base demand peak forecasts.
3. Produce the demand forecast in the framework necessary for planning. The 2023 Electric Report's analyses have specific input requirements. For example, we could have run the demand forecast with the climate projections from each of the three models, but this would have created three base forecasts. Instead, we created one demand forecast so we did not have to run the 2023 Electric Report analyses three times.

2.2.2. Choose the Data

We considered the following questions when we decided what data to use to define a new normal temperature:

1. How many years of data should we include when calculating a new normal?

   For the base energy demand forecast, we have historically used the last 30 years of temperatures to determine the normal. This approach created a relatively stable normal, with minor changes yearly. Forecasts that use five- or 10-year derived normal can have much larger swings in the year-to-year normal, creating difficulties for planning. We wanted to avoid this difficulty, so we opted to use a 30-year calculation centered on the year of interest. We used temperatures from the prior 15 and the coming 15 years for each forecast year in the analysis. We performed this calculation for each year of the forecast.

2. Should we use one climate model to predict future temperatures or all three models the NWPCC chose to create the normal?

   Since NWPCC used three models representing a wide range of possible climate outcomes, using all the climate models allowed us to capture a broad range of possible outcomes, so we used all three.

3. Should the forecasted new normal temperature include historical data, climate model projections, or some combination of the two?

   Recent historical data is a way to link climate change projections to what has occurred recently in the region. Incorporating recent data can help determine where the forecast should start. For example, in 2021, the region saw unprecedented hot temperatures, including 107º Fahrenheit at Sea-Tac Airport on June 28, 2021. However, the climate models did not predict a temperature this high until 2035. Based on this assessment, the team at PSE used historical data and forecasted temperatures to calculate a new normal temperature.

4. Should the forecast of normal temperatures be flat, as in past IRPs, or should the forecast reflect a trend?

   We wanted to reflect average temperatures warming over time, so the normal energy forecast reflected this with increasing average temperatures in the winter and increasing average temperatures in the summers.

2.3. Normal Temperature for Energy Demand Forecast

We incorporated the normal temperatures into the base energy demand forecast models through heating degree days (HDDs) and cooling degree days (CDDs). We used the HDDs and CDDs to model future energy demand. HDDs and CDDs are standard ways to express temperatures and are used to estimate how much heating or cooling a customer may operate in response to a given daily temperature. We calculate degree days using a base temperature, typically 65ºF, and the average daily temperature. For HDDs, we calculate the value as the amount the daily temperature is below 65°F, and for CDDs, it is the amount the daily temperature is above 65°F. For example, a 70°F-day will have 5 CDDs and 0 HDDs, while a 30°F-day will have 35 HDDs and 0 CDDs, using a base of 65°F. The team used the three climate models described and historical temperatures to create HDDs and CDDs. The climate models and the historical data are from NOAA's Sea-Tac Airport station.

Previously, we calculated HDDs and CDDs using the most recent 30 years of historical temperatures and used that static calculation through the forecast period, creating a flat normal temperature. For the 2023 Electric Report, we calculated the HDDs and CDDs for each year of the forecast using a different set of temperatures. We calculated HDDs and CDDs for each forecast year using temperatures from the prior 15 and the future 15 years, including the year of interest. If the previous 15 years included years where historical temperatures were available, we used historical data. We used temperatures from each of the three climate models for future years. Figures 6.1 and 6.2 show examples of the old and new normal temperatures, which include climate change.

Figure 6.1: Heating Degree Days, Previous Normal Temperature, and Current Normal Temperature Assumptions (HDD base temperature 65)

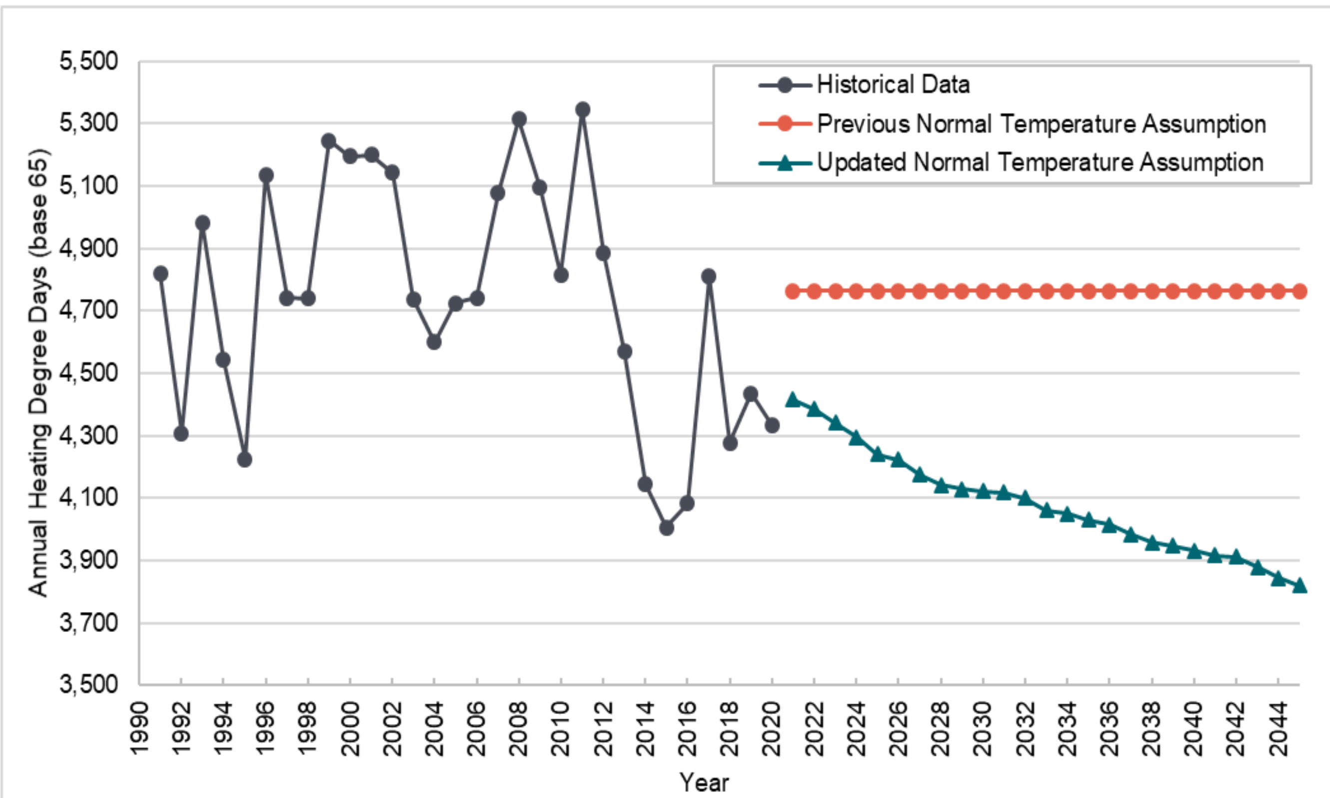
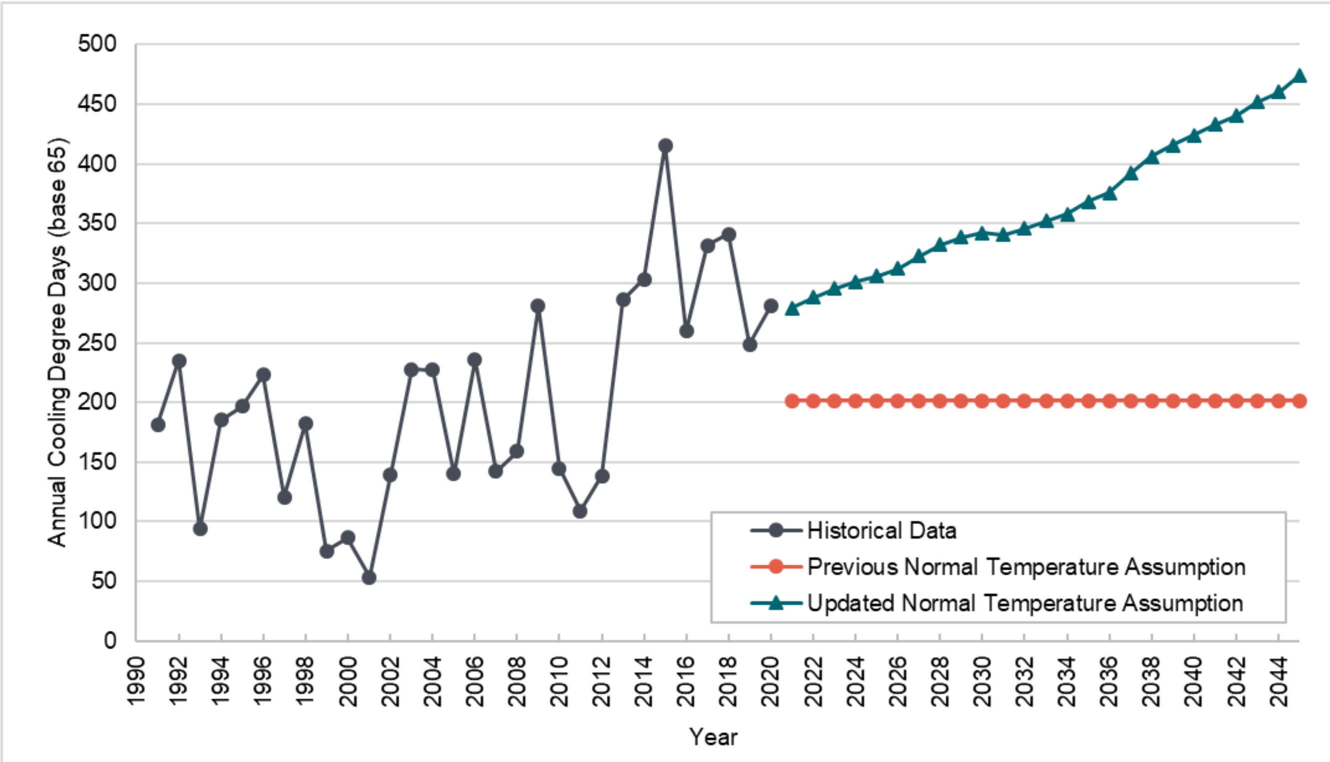


Figure 6.2: Cooling Degree Days, Previous Normal Temperature, and Current Normal Temperature Assumptions (CDD base temperature 65)



➔ See Appendix F: Demand Forecasting Models for more information about calculating the HDDs and CDDs that went into the demand forecast.

2.4. Normal Temperature for Peak Demand Forecast

The peak demand forecast uses a 1-in-2 seasonal peak minimum or maximum temperature during all peak hours. For the electric normal peak, we used a similar methodology as the normal energy demand forecast; we used data from 15 prior and 15 future years, including the year of interest, for the calculation. However, instead of averaging the 30 years of data for the peak, we calculated the 1-in-2 occurrence of a peak hour or median peak temperature.

We performed this calculation for each year in the forecast period: winter morning peaks, winter evening peaks, and summer peaks. The result was a 1-in-2 peak temperature of 25 in 2024, which increases to 26 degrees for winter morning peaks. For winter evening peaks, the 1-in-2 peak temperature is 27 for 2024 –2028 and rises to 28 for the rest of the forecast period. In the summer, the 1-in-2 peak is 94 for 2024–2028, 95 for 2029–2032, and 96 starting in 2033. We smoothed the peak normal temperatures to create a normal peak that increases temperature over time. We show the winter evening, winter morning, and summer peaks in Figures 6.3 and 6.4.

Figure 6.3: Normal Winter Peak Temperatures
Previous Normal and Updated Normals for Morning and Evening (ºF)

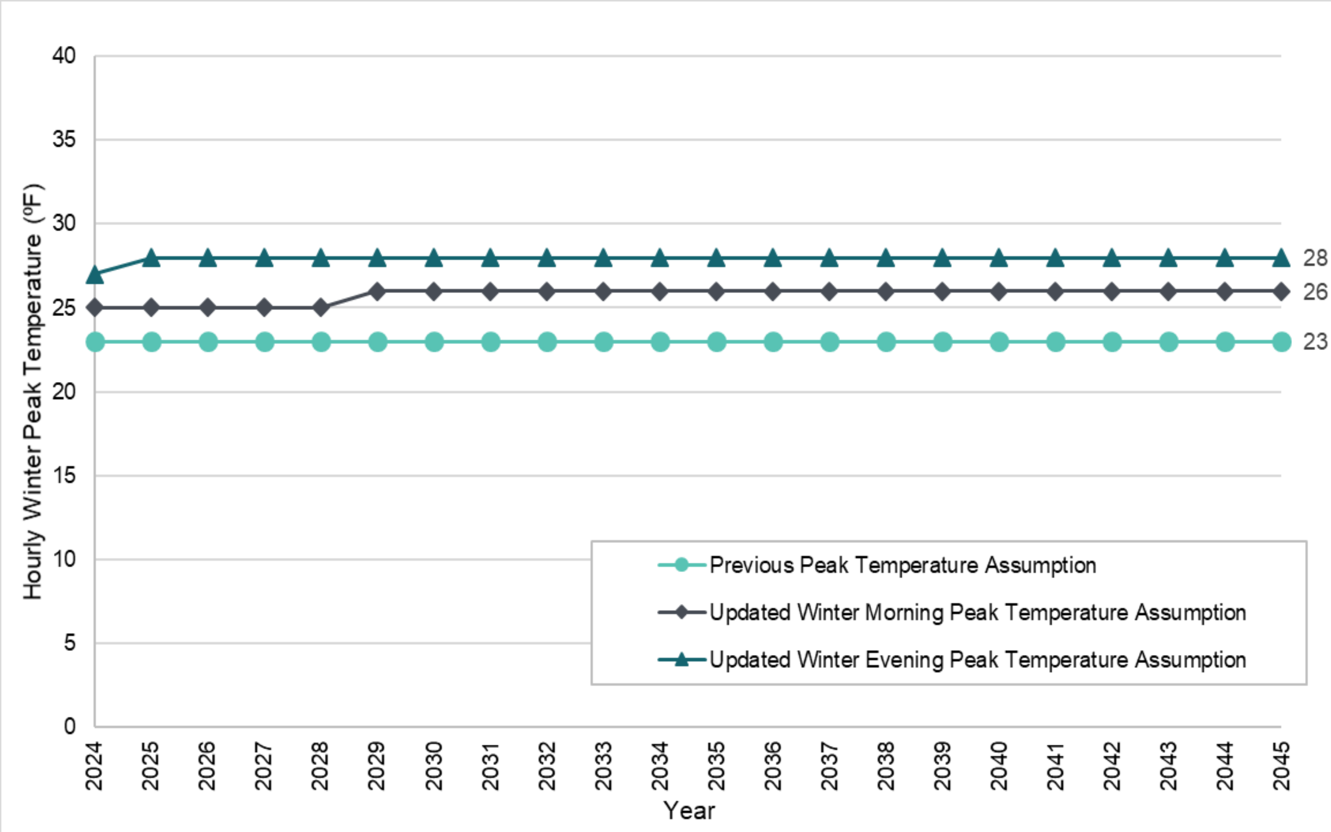
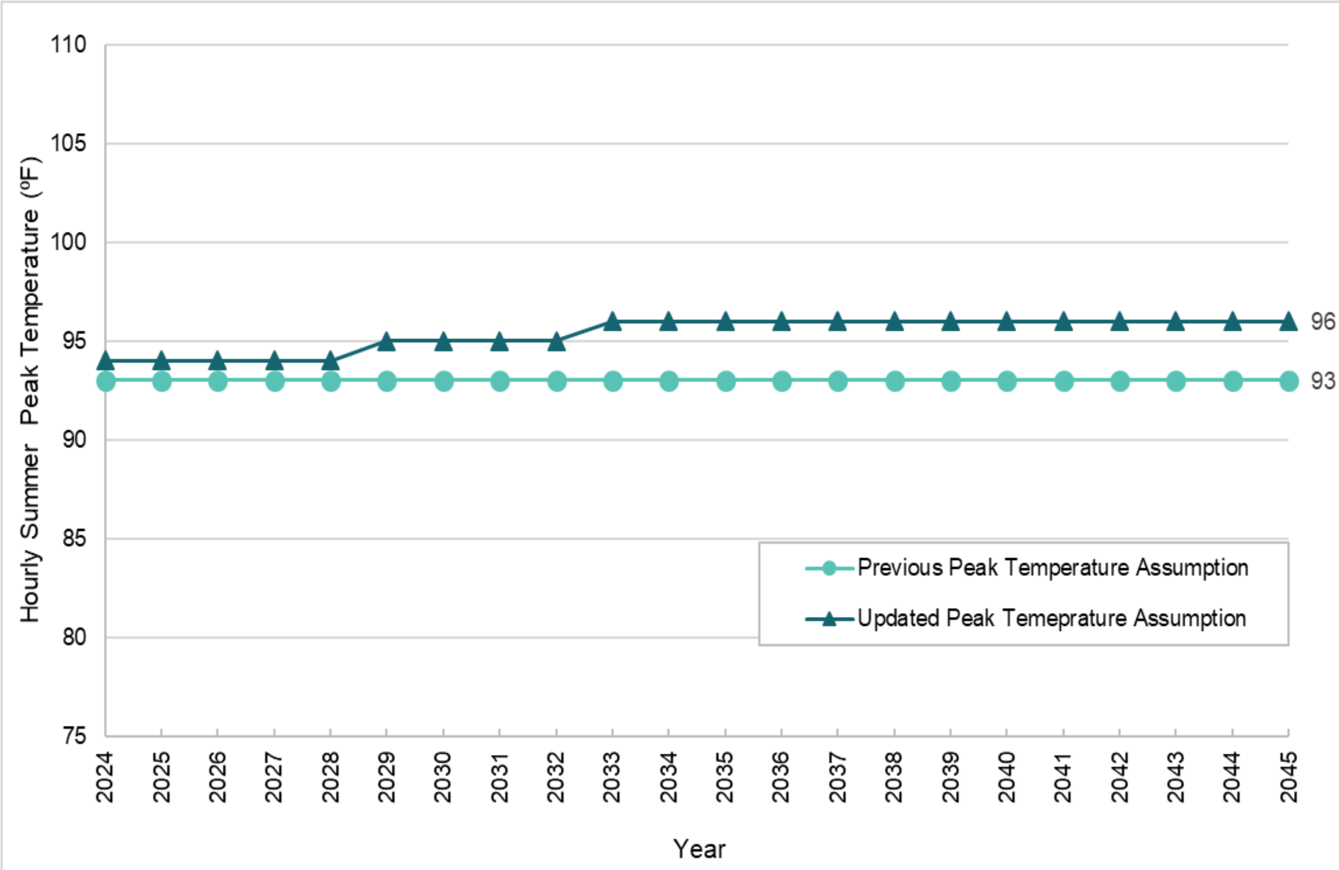


Figure 6.4: Normal Summer Peak Temperatures
Previous Normal and Updated Normal (ºF)



➔ See Appendix F: Demand Forecasting Models for a detailed discussion of the peak climate change temperature calculations.

3. Electric Demand Forecast

We present highlights of the 2023 Electric Report base demand forecast developed for the electric service area in Figures 6.5 through 6.7 and Tables 6.3 and 6.4. We summarize the population and employment assumptions for the forecast in this document's Details of Electric Forecast section and explained in detail in Appendix F: Demand Forecasting Models.

The demand forecast included only DSR measures implemented through December 2023 since the demand forecast helps determine the most cost-effective amount of DSR to include in the portfolio for subsequent periods.

3.1. Electric Energy Demand

In the 2023 Electric Report base demand forecast, we expect energy demand before additional DSR to grow at an average rate of 1.8 percent annually from 2024–2045, increasing energy demand from 2,551 aMW in 2024 to 3,699 aMW in 2045.

Puget Sound Energy serves primarily residential and commercial customers, with a minority share of energy demand associated with industrial, resale, and streetlight customer classes. Excluding losses, we projected residential and commercial customer classes to represent 49 percent and 39 percent of energy demand in 2024. During the forecast period, residential demand grows as we add new customers to the system and customers adopt electric vehicles (EVs). This demand growth is partially, but not entirely, offset by decreasing residential heating energy demand — a consequence of adopting trended normal temperatures consistent with climate change impacts.

Commercial energy demand grows similarly: we added new commercial customers to the system, and customers adopt EVs for fleet and other business purposes. The share of commercial demand associated with heating energy demand is less than residential customers; thus, climate change impacts are less severe for the commercial class.

Therefore, rising customer and EV counts drive most of the growth in energy demand and offset climate change impacts before DSR is applied.

Figure 6.5: Electric Energy Demand Forecast before Additional DSR
2023 Electric Report Base Demand Forecast versus 2021 IRP Base Demand Forecast (aMW)

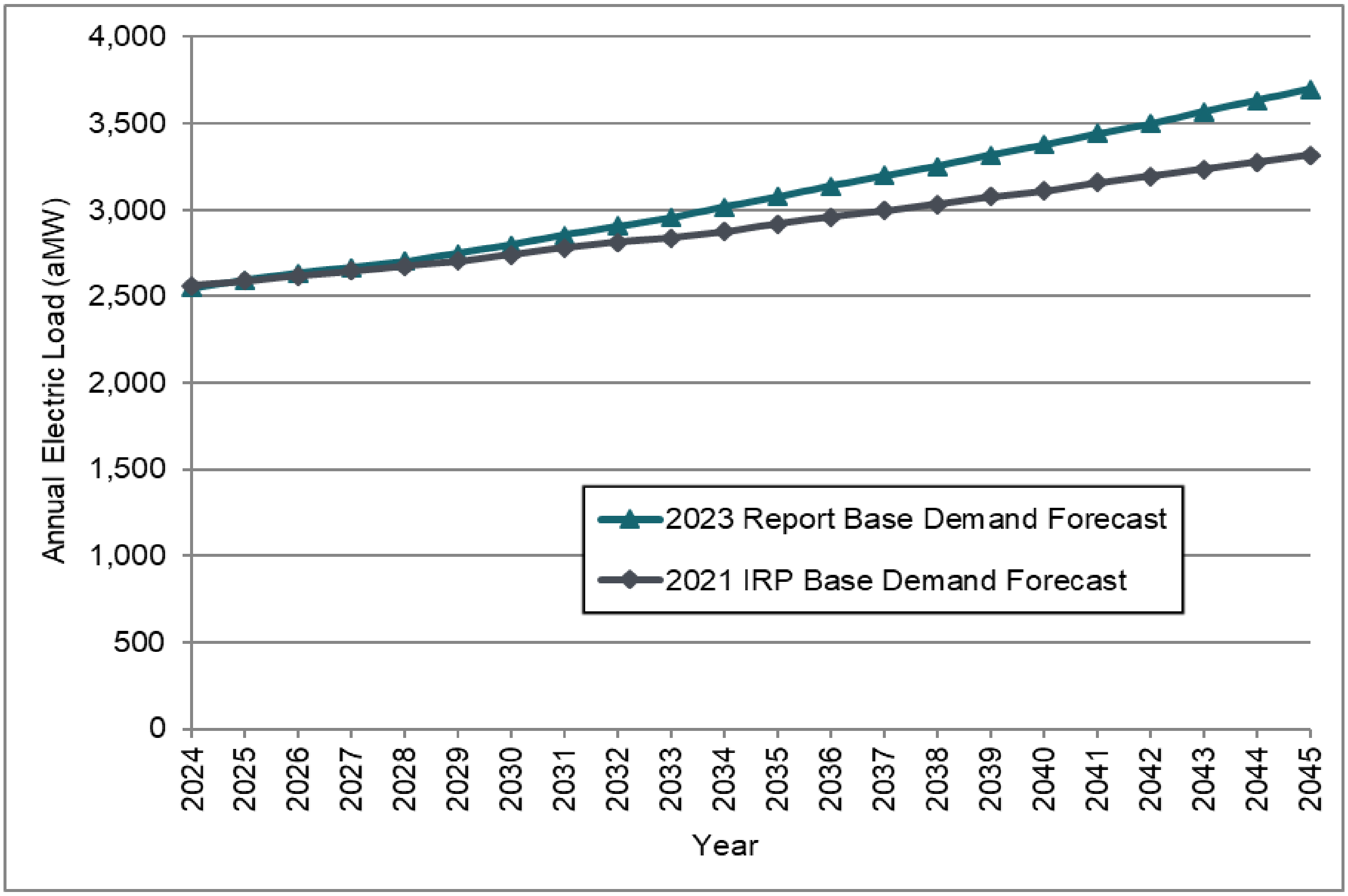


Table 6.3: Electric Energy Base Demand Forecast before Additional DSR (aMW)

Year	2024	2030	2035	2040	2045	AARG 2024-2045 (%)
Base Demand Forecast	2,551	2,799	3,076	3,378	3,699	1.8

3.2. Electric Peak Demand

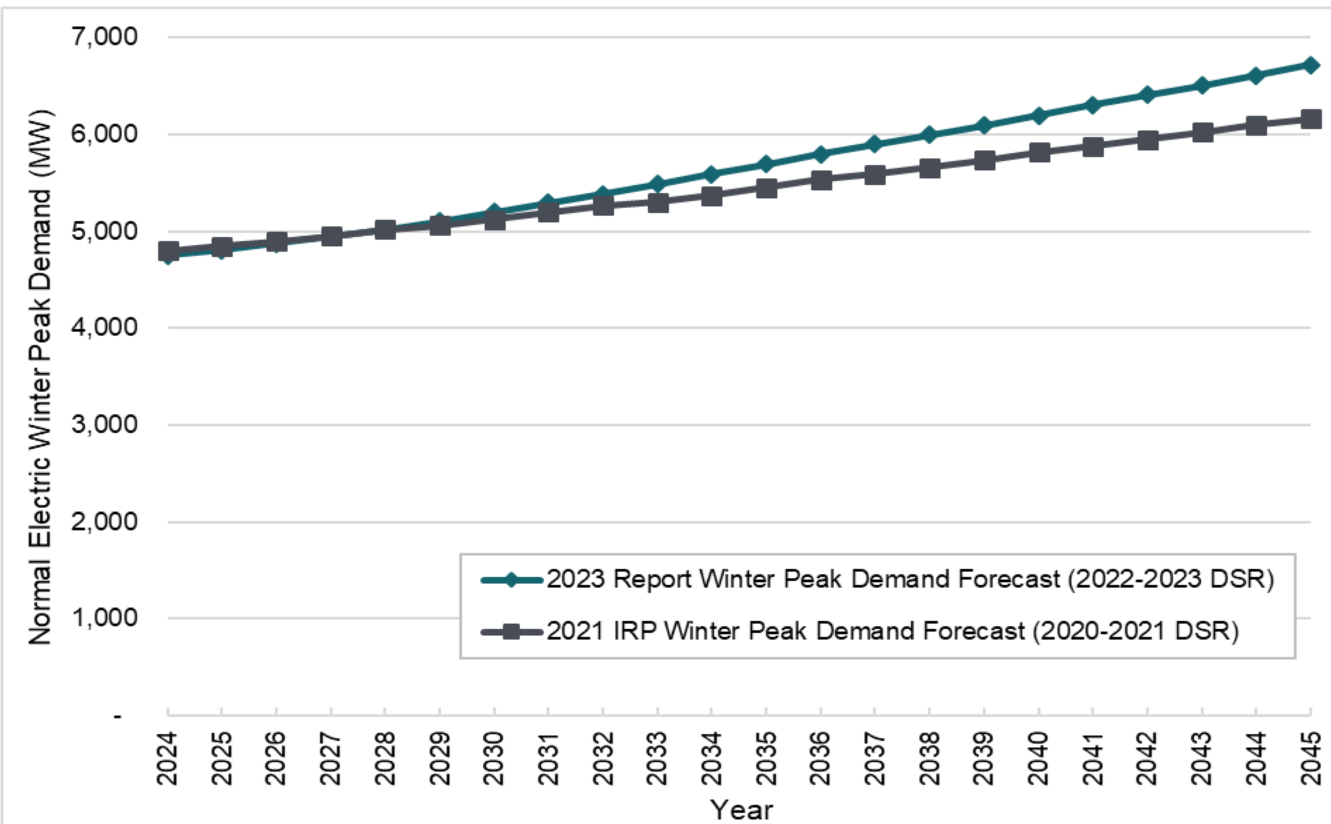
Puget Sound Energy is a winter peaking utility, which means the one hour with the highest demand of the year occurs in the winter. However, summer peaks are growing with warming summer temperatures and increased use of air conditioning and heat pumps for cooling. With the addition of data to reflect climate change modeling and the growing summer peaks, the team updated the capacity expansion model to analyze both winter and summer peaks. We provide a detailed discussion of the capacity expansion model in Appendix G, Electric Analysis Models. Different supply-side or demand-side resources may better meet a summer or a winter peak. Therefore, we consider demand during all hours of the year in resource adequacy modeling to help determine the best resources to meet the customer load. This section describes winter and summer electric peaks.

3.2.1. Winter Electric Peak Demand

We forecasted the normal electric winter peak hour demand with specific assumptions for normal peak conditions. We modeled the winter peak demand forecast with assumptions consistent with a one-in-two probability of occurrence. We define a winter peak event as a mid-week, non-holiday, and evening occurrence in December, with a temperature that reflects the climate change analysis (27- and 28-degrees Fahrenheit). We assumed these conditions because they are the expected conditions (50 percent or 1-in-2 probability) in which a peak event will occur based on historical system characteristics, forward-looking EV demand shapes, and climate change temperature projections.

It is important to note that actual winter peak demand may occur under different conditions, such as in the morning, at different temperatures, or in another month. For the base demand forecast, however, expected conditions are assumed. Please see the discussion on stochastic peak demand and hourly demand scenarios for variation in peak event conditions. Before demand-side resources, the 2023 Electric Report's base peak demand forecast grows at an average annual growth rate of 1.7 percent. This rate would increase peak demand from 4,753 MW in 2024 to 6,717 MW in 2045.

Figure 6.6: Winter Electric Peak Demand Forecast before Additional DSR
2023 Electric Report versus 2021 IRP Base Demand Forecast Hourly Annual Peak (MW)



Winter peak demand in the 2023 Electric Report base demand forecast is higher at the end of the study period (6,717 MW in 2045) than in the 2021 IRP (6,159 MW in 2045). Additionally, the 2023 Electric Report peak demand forecast has a faster average annual growth rate (1.7 percent) than the 2021 IRP (1.2 percent).

The 2023 Electric Report peak demand forecast projects faster growth than the 2021 IRP peak demand forecast because it includes a revised EV forecast that reflects more adoption and additional vehicle classes (medium and heavy duty). Observed actual customer and sales growth in 2020 and 2021 exceeded the 2021 IRP forecast, mainly due to less severe customer growth and demand declines due to economic turmoil. These positive impacts offset the step down in the forecast due to climate change and result in a forecast that starts at a point like the 2021 IRP base peak demand forecast.

3.2.2. Summer Electric Peak Demand

The team modeled the normal electric summer peak hour demand using 94 degrees Fahrenheit (2024–2029), 95 degrees Fahrenheit (2030–2033), and 96 degrees Fahrenheit (2034–2045) as the design temperatures. Summer peaks typically occur in July or August. Figure 6.7 shows the 2023 Electric Report's base peak demand forecast for the winter and summer.

The 2023 Electric Report's base summer peak demand forecast has an average annual growth rate of 2.2 percent, increasing the summer peak demand from 3,820 MW in 2024 to 6,005 MW in 2045. Because the summer peak forecast does not exceed the winter peak forecast in the timeframe shown, we assumed PSE will continue to be a winter peaking utility for the planning period of this 2023 Electric Report.

Figure 6.7: Winter and Summer Electric Peak Demand Forecasts before Additional DSR
Hourly Annual Peak (MW)

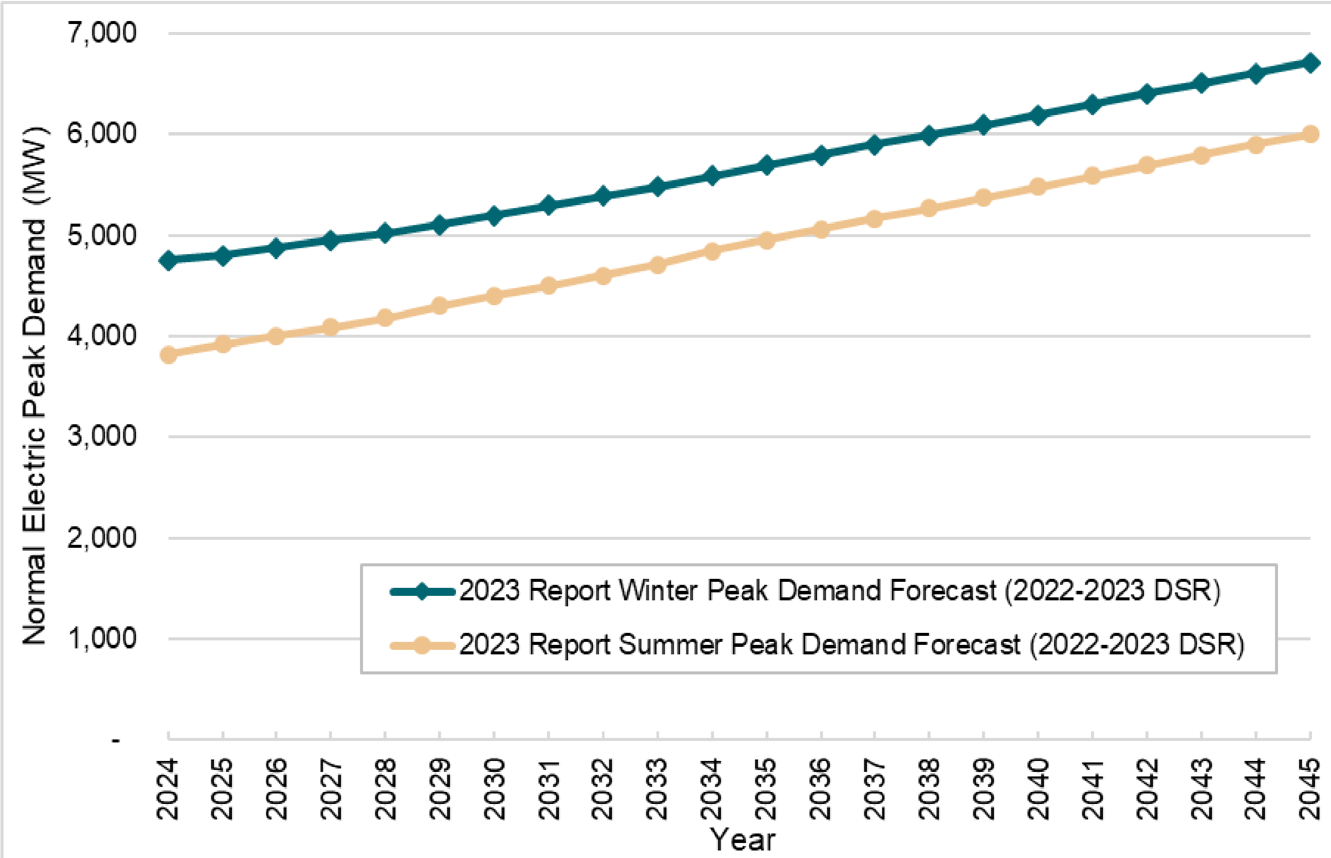


Table 6.4: Electric Peak Demand Forecast before Additional DSR
Winter and Summer Peaks, Hourly Annual Peak (MW)

Year	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Winter Demand Forecast	4,753	5,197	5,693	6,198	6,717	1.7
Summer Demand Forecast	3,820	4,401	4,953	5,481	6,005	2.2

The 2023 Electric Report's winter peak demand forecast consistently stays higher than the summer peak demand forecast for the entire planning horizon. Even with the projected higher growth rate using the climate change data for summer peak demand, the summer peak still does not come close to the winter peak. The spread between the two peaks goes from more than 900 MW in 2024 to more than 700 MW in 2045.

3.3. Impacts of Demand-side Resources

As we explained at the beginning of this chapter, the electric demand forecasts include only demand-side resources implemented through December 2023 since the demand forecast helps determine the most cost-effective level of DSR to include in the portfolio. To examine the effects of DSR on the energy and peak forecasts, we applied the cost-effective amount of DSR determined in this 2023 Electric Report[3] to the base energy and peak demand forecasts for 2024–2045. To account for the 2013 general rate case Global Settlement,[4] we also applied an additional 5 percent of DSR for that period. Teams at PSE use forecasts with DSR for financial and system planning decisions. We illustrate the results in Figures 6.8 thru 6.10.

3.3.1. DSR Impact on Energy Demand

When we applied the DSR bundles chosen in the 2023 Electric Report portfolio analysis to the energy demand forecast:

- Electric energy demand after additional DSR grows at an average annual rate of 0.72 percent from 2024 to 2045
- Electric energy demand in 2045 will be reduced by 21 percent to 2,949 aMW

3.3.2. DSR Impact on Peak Demand

When we applied the DSR bundles chosen in the 2023 portfolio analysis to the winter evening and summer peak demand forecast:

- Electric system winter peak demand in 2045 is reduced 13 percent to 5,867 MW
- Electric system winter peak demand after additional DSR grows at an average annual rate of 1.0 percent from 2024 to 2045
- Electric system summer peak demand in 2045 is reduced 17 percent to 5,003 MW
- Electric system summer peak demand after additional DSR grows at an average annual rate of 1.3 percent from 2024 to 2045

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

[4] For an Order Authorizing PSE to Implement Electric and Natural Gas Decoupling Mechanisms and To Record Accounting Entries Associated With the Mechanism, Docket UE-121697 and UG-121705, Washington Utilities and Transportation Commission. Page 73 Line 162.

Figure 6.8: Electric Energy Demand Forecast (aMW), before Additional DSR and after Additional DSR

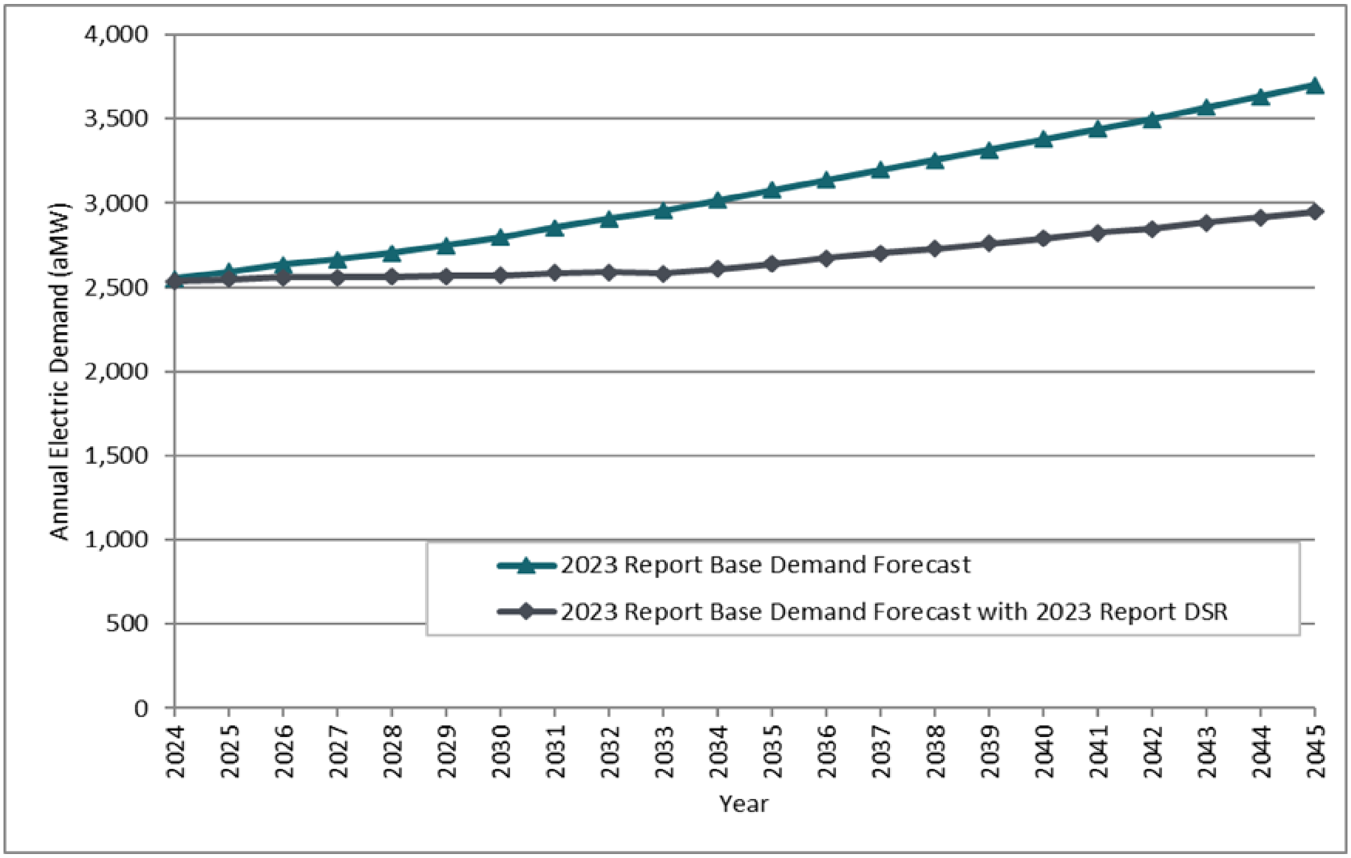


Figure 6.9: Electric Winter Peak Demand Forecast (MW), before Additional DSR and after Additional DSR

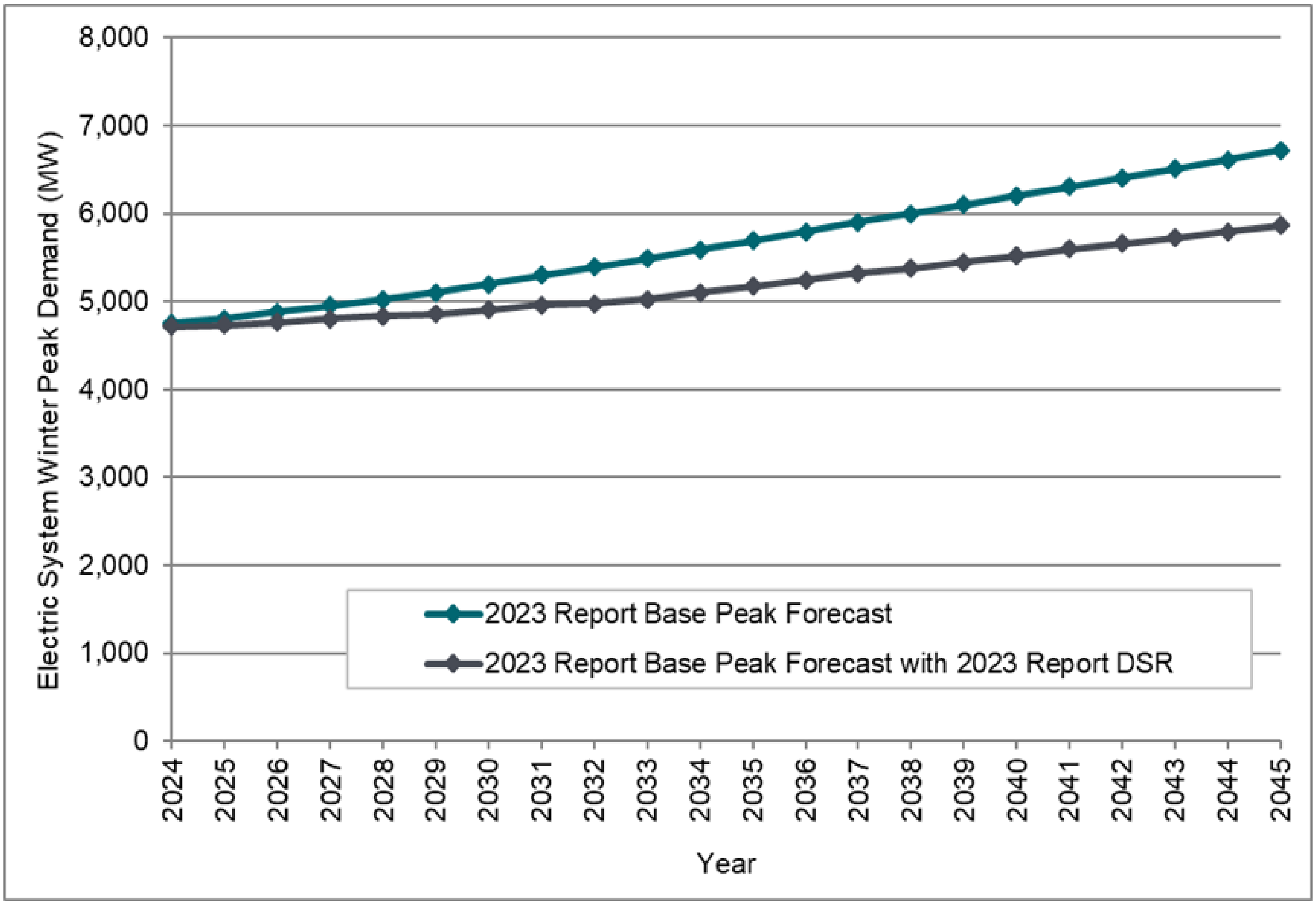
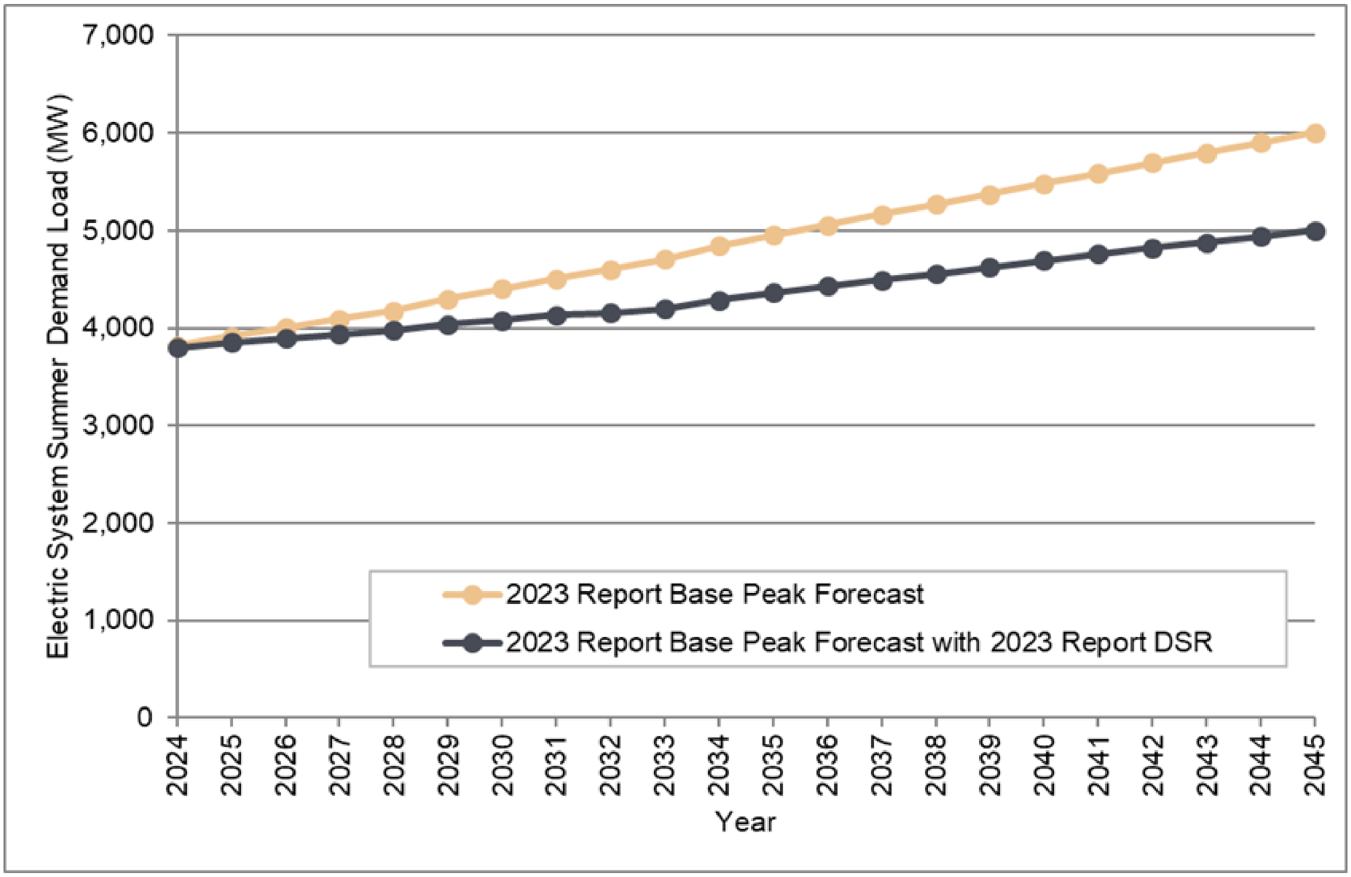


Figure 6.10: Electric Summer Peak Demand Forecast (MW), before Additional DSR and after Additional DSR



3.4. Details of the Electric Forecast

The electric forecast is comprised of demand from several different classes. These classes are residential, commercial, industrial, streetlight, and resale. We show details of each class in the following section.

3.4.1. Electric Customer Counts

We expect system-level customer counts to grow by 1.1 percent per year, from 1.25 million customers in 2024 to 1.57 million in 2045. This rate is faster than the average annual growth rate of 1.0 percent projected in the 2021 IRP base demand forecast.

Residential customers are PSE's largest customer class, with an approximately 88 percent share of electric customers by 2024. During the forecast period from 2024 to 2045, we expect residential customer counts to grow at an average annual rate of 1.1 percent per year. Commercial customers are PSE's second largest customer class, around 11 percent of total customers, and are expected to grow at an average annual rate of 1.3 percent per year over the forecast period. Industrial customer counts, around 0.3 percent of total customers, are expected to decline, following the historical trend of declining industrial activities in the service area. We expect these trends to continue as the economy in PSE's service area shifts toward more commercial and less industrial business sectors.

Table 6.5: December Electric Customer Counts by Class,
2023 Report Base Demand Forecast

Class	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Total	1,251,677	1,344,744	1,421,065	1,495,183	1,571,637	1.1
Residential	1,101,482	1,182,249	1,247,366	1,309,627	1,373,711	1.1
Commercial	138,449	149,815	160,282	171,484	183,126	1.3
Industrial	3,195	3,093	3,016	2,945	2,869	-0.5
Other	8,543	9,579	10,393	11,119	11,923	1.6

3.4.2. Electric Demand by Class

Over the next 20 years, we expect the residential and commercial classes to have positive demand growth, with the commercial class growing faster than the residential class before additional DSR. New customers and our projected rate of EV adoption create residential and commercial class demand growth.

Table 6.6: Electric Energy Demand by Class,
2023 Report Base Demand Forecast Before Additional DSR

Class	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Total	2,551	2,799	3,076	3,378	3,699	1.8
Residential	1,245	1,379	1,517	1,652	1,763	1.7
Commercial	986	1,085	1,204	1,349	1,534	2.1
Industrial	113	108	106	104	103	-0.5
Other	8	8	9	9	10	1.3
Losses	199	218	240	263	289	-

3.4.3. Electric Use per Customer

We expect residential use per customer, before additional DSR, to increase over the forecast period. Before EV adoption and climate change assumptions, residential use per customer is flat, but new demand from EVs outpaces usage losses due to lower normal HDDs due to the climate change update, resulting in positive net average use per customer demand growth. We expect commercial use per customer to increase over the forecast period due to EV adoption and higher normal CDDs. The non-residential classes have a lower share of energy demand devoted to heating, thus, are less impacted in the winter by lower normal HDDs.

Table 6.7: Electric Use per Customer,
2023 Report Base Demand Forecast Before Additional DSR

Type	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Residential	10.0	10.3	10.7	11.1	11.3	0.5
Commercial	62.8	63.7	66.1	69.4	73.7	0.7
Industrial	310.6	306.6	308.6	311.1	312.2	-0.1

3.4.4. Electric Customer Count and Energy Demand Share by Class

Table 6.8 shows customer counts as a percent of PSE's total electric customers. We show demand share by class in Table 6.9. We expect the share of residential customers and demand to remain stable over the forecast period before adjustment by the final DSR in the report analysis.

Table 6.8: December Customer Count Share by Class

Class	Share in 2024 (%)	Share in 2045 (%)
Residential	88.00	87.41
Commercial	11.06	11.65
Industrial	0.26	0.18
Other	0.68	0.76

Table 6.9: Energy Demand Share by Class, Before Additional DSR

Class	Share in 2024 (%)	Share in 2045 (%)
Residential	48.79	47.67
Commercial	38.67	41.49
Industrial	4.44	2.77
Other	0.30	0.27
Losses	7.80	7.80

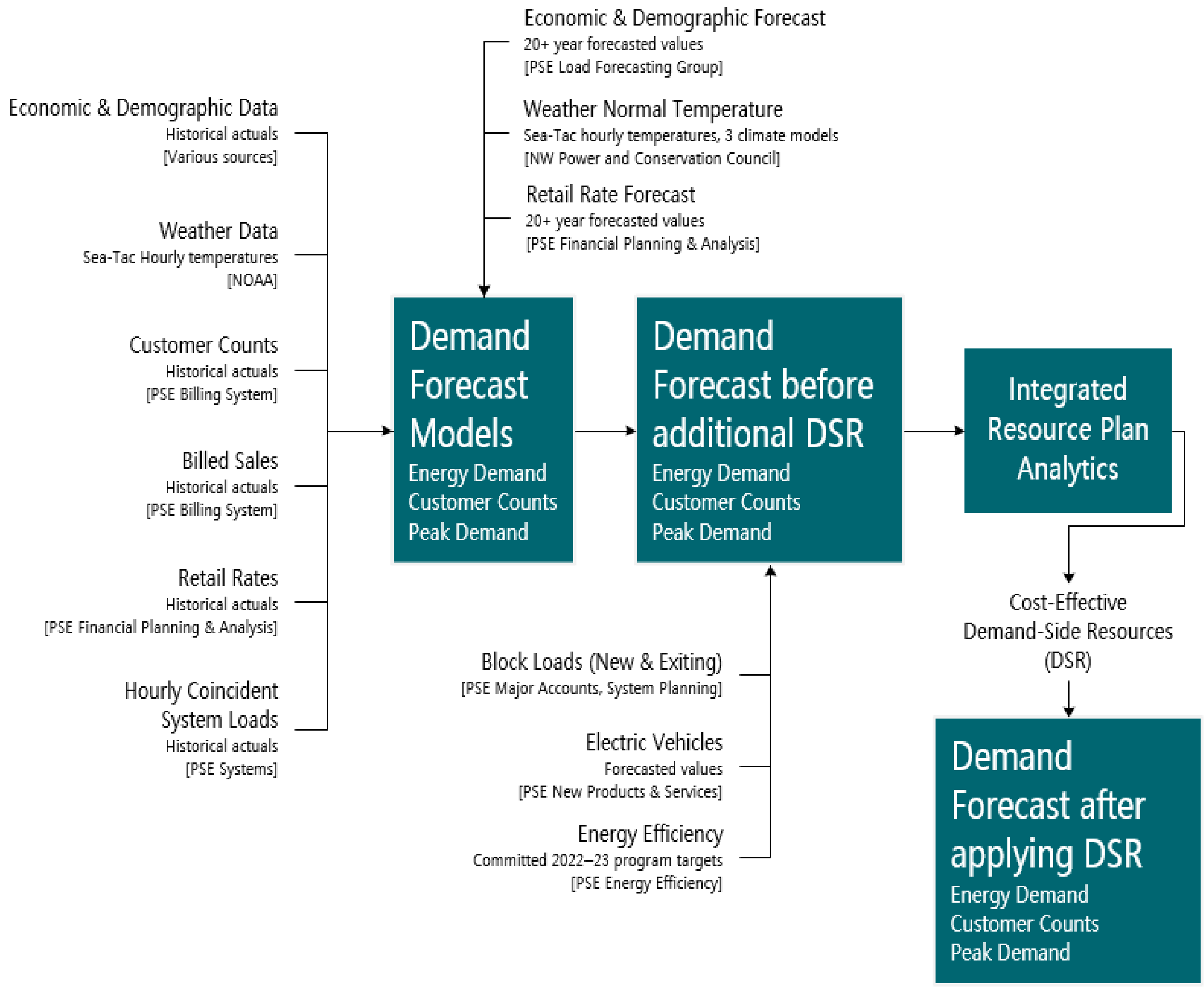
4. Methodology

We create relationships between historical growth and historical conditions to forecast customer demand. Therefore, we can use forecasted future conditions to forecast future growth. In the following section, we discuss how we forecasted demand.

4.1. Forecasting Process

Our regional economic and demographic model uses national and regional data to forecast total employment, employment types, unemployment, personal income, households, and consumer price index (CPI) for the PSE electric service area. We built the regional economic and demographic data used in the model from county-level information acquired from various sources. This economic and demographic information is combined with other PSE internal information to produce the base energy and peak demand forecasts for the service area. We illustrate the demand forecasting process in Figure 6.11 and list the economic and demographic input data sources in Table 6.10.

Figure 6.11: PSE Demand Forecasting Process



We divided customers into classes and service levels that use energy for similar purposes and at comparable retail rates to forecast energy sales and customer counts. We modeled the different classes and service levels using variables specific to their usage patterns. Electric customer classes include residential, commercial, industrial, streetlights, and resale. Although PSE provides electric transmission services to customers who purchase power from third-party suppliers, we did not include demand from these customers in the 2023 Electric Report's demand forecast.

We used multivariate time series econometric regression equations to derive historical relationships between trends and drivers and then employed them to forecast the number of customers and use per customer by class or service level. We multiplied these factors to arrive at the billed sales forecast. The main drivers of these equations include population, unemployment rates, retail rates, personal income, HDDs, CDDs, total employment, manufacturing employment, CPI, and U.S. Gross Domestic Product (GDP). We calculated demand from sales and included transmission and distribution losses in addition to sales. We based weather inputs on NOAA temperature readings at Sea-Tac Airport and incorporated historical and forecasted temperatures, including the effects of climate change. We also projected peak system demand by evaluating the historical relationship between actual peaks, the temperature at peaks, average system demand, day of the week, time of day, holidays, and estimated air conditioning trends. We forecasted peak demand with the future temperature at peak plus expected EV peak demand growth.

➔ See Appendix F: Demand Forecasting Models for detailed descriptions of the econometric methodologies used to forecast billed energy sales, customer counts, peak demand, hourly distribution of electric demand, and forecast uncertainty.

Table 6.10: Sources for County Economic and Demographic Data 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 the 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	U.S. Bureau of Economic Analysis (BEA) www.bea.gov
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	U.S. Census www.census.gov
Aerospace employment, Regional Consumer Price Index (CPI)	Puget Sound Economic Forecaster www.economicforecaster.com

We obtained country-level economic and demographic data from Moody's Analytics.[5] The inputs into PSE's economic and demographic model from Moody's Analytics are gross domestic product (GDP), industrial production index, employment, unemployment rate, personal income, wages and salary disbursements, consumer price index (CPI), housing starts, population, conventional mortgage rate, and the three-month T-bill rate.

4.2. Stochastic Scenarios

We used stochastic analysis[6] to look at variability in our assumptions. We developed 310 stochastic scenarios to examine changes in the economic, demographic, electric vehicle, and temperature assumptions. We also examined model uncertainty in the stochastics. These 310 alternate future pathways for customer growth, energy demand per customer, and peak demand let us test the portfolio to see how it responds to conditions other than the base demand.

5 economy.com
6 Stochastic scenarios are created with a randomly determined set of inputs, which creates a probability distribution.

We created and ran 310 electric stochastic scenarios in the AURORA portfolio model to test the portfolio's robustness under various conditions. We show the range of the stochastics in Figures 6.12 through 6.14. Energy demand in 2045 ranges from 2,724 aMW to 4,743 aMW in the energy stochastic scenarios. Winter peak demand in 2045 ranges from 5,160 MW to 8,551 MW, and summer peak demand in 2045 ranges from 4,438 MW to 7,171 MW in the peak stochastic scenarios.

We develop stochastic simulations with outputs from PSE's economic and demographic model, variation in underlying econometric model uncertainty, electric vehicle adoption, and future temperatures from three climate models. We modeled electric energy and peak demand stochastic scenarios using 310 stochastic simulations. The stochastic simulations reflect variations in key regional economic and demographic variables such as population, employment, and income. The simulations also capture model uncertainty through stochastic variation of model statistics associated with underlying econometric models of average energy demand per customer, customer growth, and peak demand. We held electric vehicle assumptions constant in 250 scenarios, applied a high EV forecast to 30 scenarios with high economic outlooks relating to total employment, and applied a low EV forecast to another 30 scenarios with low economic scenarios with respect to total employment.

The stochastic scenarios use future temperatures from the CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA models, reflecting higher or lower temperature conditions. We sampled forecasted temperature years 2020–2049 from the three models for the 310 draws.

We ran the 310 electric stochastic scenarios in the AURORA portfolio model to test the portfolio's robustness under various conditions.

➔ Detailed descriptions of the stochastics are available in Chapter Eight: Electric Analysis.

Figure 6.12: Range of Energy Demand in Stochastic Scenarios Around Base Energy Demand Forecast (aMW) Before Additional DSR

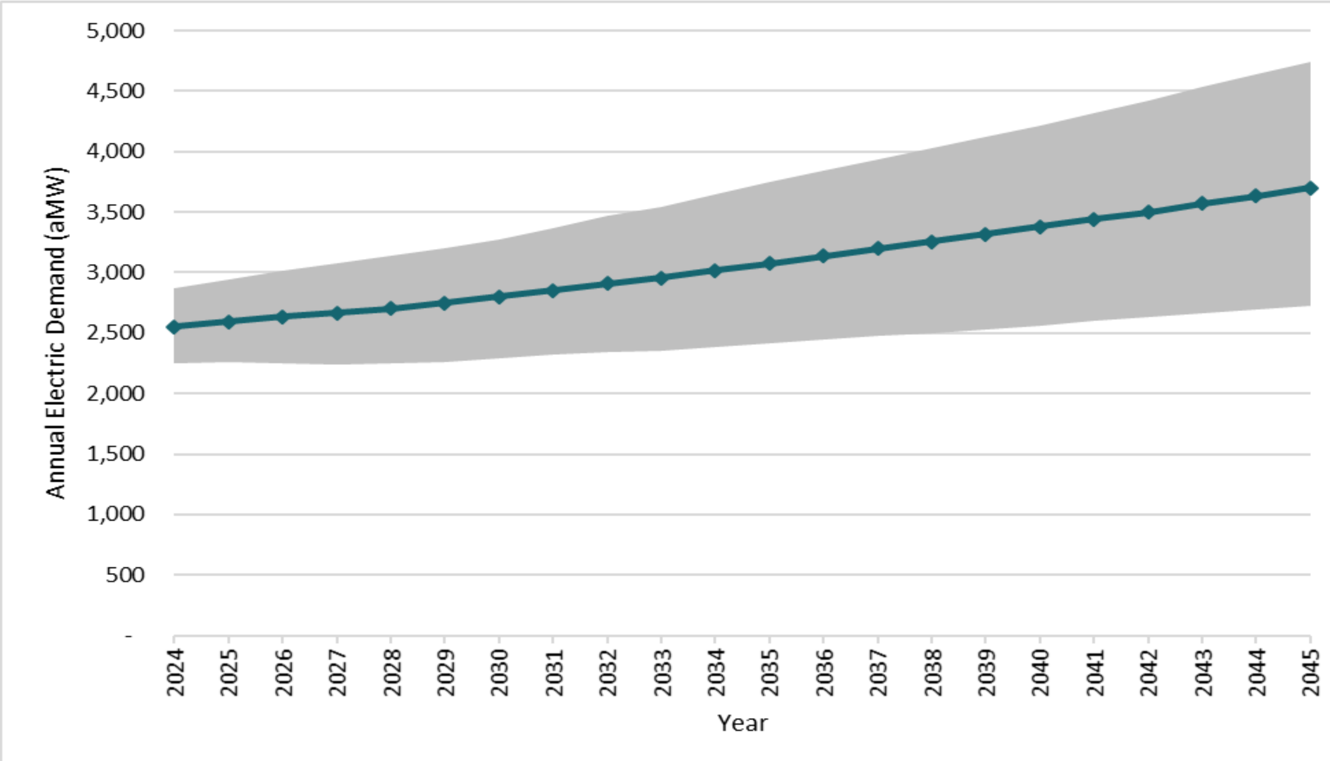


Figure 6.13: Range of Winter Peak Demand in Stochastic Scenarios around Base Peak Demand Forecast (MW) Before Additional DSR

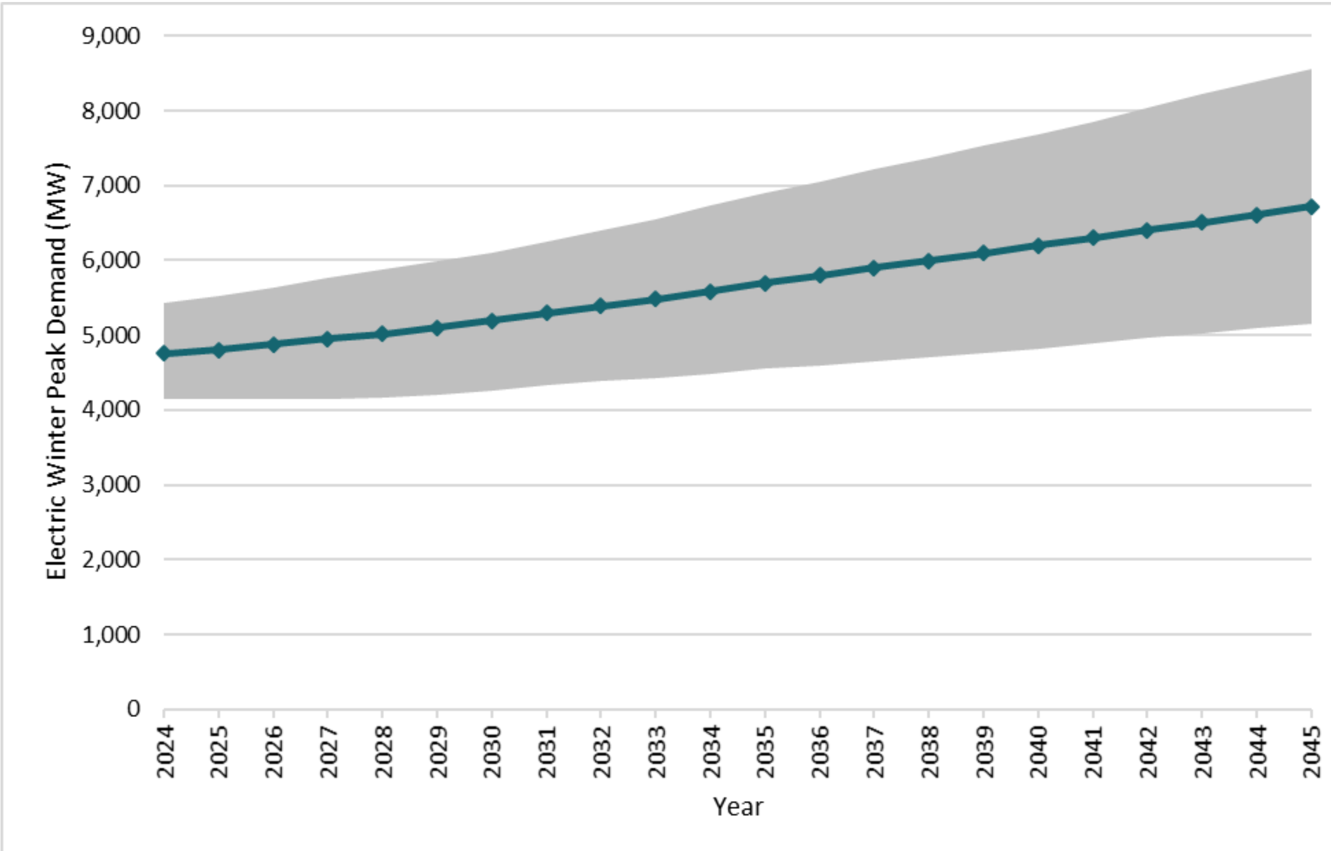
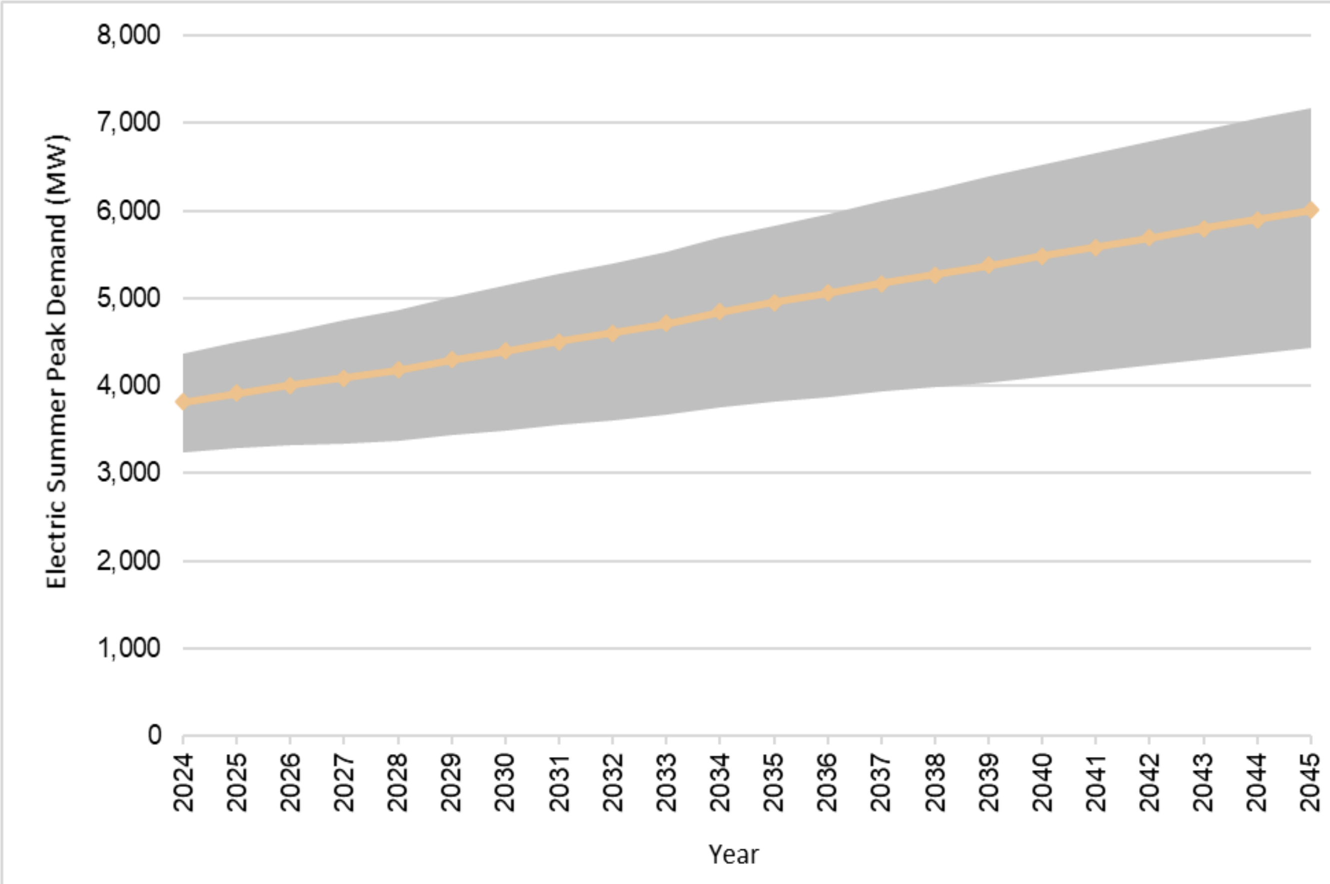


Figure 6.14: Range of Summer Peak Demand in Stochastic Scenarios around Base Peak Demand Forecast (MW) Before Additional DSR



➔ See Appendix F: Demand Forecasting Models for a detailed discussion of the stochastic simulations.

4.3. Resource Adequacy Model Inputs

In addition to the stochastic scenarios mentioned in the previous section, we also developed 90 electric demand draws for the resource adequacy (RA) model. We created these demand draws with stochastic outputs from PSE's economic and demographic model and two consecutive future weather years using the future temperatures from the climate change models. Since the RA model examines a hydro year from October through September, drawing two consecutive years preserves the characteristics of each future heating season. We created RA demand draws for the hydro years 2028–2029 and 2033–2034.

The RA model also examines adequacy in each hour of a given year; therefore, we scaled the 90 demand draws we used for RA model inputs to hourly demand using the hourly demand model. We created each of the 90 hourly demand forecasts without electric vehicle demand to account for growth in electric vehicles, then added the hourly forecast of electric vehicle demand to each demand forecast to create the final 90 hourly demand forecasts.

We highlight the differences between the RA model inputs and the stochastic scenarios in Table 6.11.

Table 6.11: Differences between the Resource Adequacy Model Inputs and the Stochastic Scenarios

Analysis Attribute	Stochastic Scenarios	Resource Adequacy Model
Number of draws	310	90
Forecasted years	2024–2045	October 2028–September 2029 and October 2033–September 2034
Model detail level	Monthly demand and peak demand	Hourly demand
Economic and demographic variation	Included	Included
Climate change impacts	Yes	Yes
Temperature assumptions	Forecasted temperatures from years 2020–2049 were sampled from the three climate change models — one year chosen for each draw	Forecasted temperatures from years 2020–2049 were used from the three climate change models — two consecutive weather years were chosen for each draw
Electric vehicles	Base forecast used in 250 draws, high used in 30 draws, low used in 30 draws	Base forecast used in each draw
Electrification and other conversion policies	No	No
Purpose	Used in the AURORA portfolio model to test the robustness of the portfolio under various conditions	Used in the resource adequacy modeling that determines the effective load-carrying capabilities (ELCCs)

➔ See Chapter Seven: Resource Adequacy Analysis, and Appendix F: Demand Forecasting Models for a detailed discussion of the hourly model.

4.4. Updates to Inputs and Equations

The following section summarizes updates to the demand forecast inputs and equations made since the 2021 IRP.

4.4.1. Climate Change Forecast

Previous IRPs used the most recent 30 years of historical temperatures to forecast what temperatures will be during the forecast. In this 2023 Electric Report, we used three climate change models by the NWPCC to establish an assumption of future normal temperatures. Section 2 Climate Change of this chapter details how we developed and used climate models in the forecast of this chapter details how we developed and used climate models in the forecast.

4.4.2. Peak Modeling of Morning versus Evening

This 2023 Electric Report explicitly assumes an evening peak and its temperature impacts. Although a winter peak may occur in the morning or the evening, current characteristics of PSE's system demand indicate, on a weather and day-of-week normalized basis, higher levels of demand in the evening (around 200 MW) compared to the morning. This finding is consistent with historically observed December peaks (hour ending 18 on a weekday). Additionally, in the future forecast period, as the EV forecast grows, the difference between morning and evening peaks grows to be more than a few hundred MWs with larger EV peak demand in the evening, thus further decreasing the long-term likelihood of a morning peak occurrence. As part of our evaluation of the climate change temperature models, we recognized that the one-in-two minimum seasonal, hourly temperature for a winter evening is warmer than the morning. Hence, we calculated the typical effect of this assumption in the climate change datasets, which results in around two-degree warming to reflect evening conditions. This update reduced the winter peak demand forecast. This assumption does not impact summer peak temperature projections, as summer peaks always occur in the evening when the temperature is warmest.

4.4.3. 2018 Washington State Energy Code

The 2018 Washington State energy code change took effect in 2021. We considered the impact of this code change from 2021 through 2023 in the 2023 Electric Report forecast to understand the starting point for the forecast in 2024. The Conservation Potential Assessment (CPA) will determine the effects of this code change starting in 2024 and will also include the statutory requirement for the Washington State code cycle to make the code more stringent in terms of energy use. The law requires that the WA State code be improved in each code cycle update to achieve a 70 percent reduction in energy use by 2031 compared to the 2006 WA State code baseline. Therefore, a small amount of this code change is in the forecast, but we will account for most of this code change after the additional DSR forecast.

5. Key Assumptions

To develop PSE's demand forecasts, we must make assumptions about economic growth, energy prices, weather, and loss factors, including certain system-specific conditions. We describe these and other assumptions in the following section.

5.1. Economic Growth

Economic activity has a significant effect on long-term energy demand. Although 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 and cooling, water heating, lighting, cooking, dishwashing, clothes washing, electric vehicles, and other electric plug loads. The growth in the 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 other plug loads. Energy is also a critical input into many industrial production processes. Economic activities in the commercial and industrial sectors are, therefore, essential indicators for the overall trends in energy consumption.

5.1.1. National Economic Outlook

Because the Puget Sound region is a major commercial and manufacturing center with strong links to the national economy, the 2023 Electric Report 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. We used the November 2021 Moody's forecast for this 2023 Electric Report.

The Moody's forecast predicts:

- The economy will continue to recover from the COVID-19 pandemic with a return to full employment in 2023, and labor force participation will continue to increase as workers get healthy and children get vaccines.
- The recovery will continue through 2025. After 2025, Moody's predicts the economy will grow modestly in the long term.
- U.S. GDP will continue to grow over the forecast period with a 2.0 percent average annual growth from 2024–2045. This growth rate is lower than the Moody's forecast used in the 2021 IRP, which projected 2.2 percent average annual growth, but some of the 2021 IRP growth was from the projected recovery from COVID-19.

Moody's identified possible risks that could affect the accuracy of this forecast:[7]

- In the near term, supply constraints could cause the economy to grow less quickly.
- Rising long-term interest rates could cause a slump in the economic recovery.
- The congressional stimulus for COVID-19 could be smaller than predicted or not provide the boost to the economy that is predicted.
- The economic effects of COVID-19 are still unpredictable; additional waves that elude the vaccine could halt recovery.

5.1.2. Population Outlook

The Washington State Employment Security Department (WA ESD) average annual growth rate for the counties that make up the electric service area is 0.88 percent for 2024–2045. This rate is down from the 1.0 percent growth rate forecast in the 2021 IRP 2022–2045.

5.1.3. Regional Economic Outlook

We prepare regional economic and demographic forecasts using econometric models based on historical economic data for our service area counties and the United States macroeconomic forecasts.

Puget Sound Energy's electric service area stretches from south Puget Sound to the Canadian border and from central Washington's Kittitas Valley west to the Kitsap Peninsula. Puget Sound Energy serves more than 1.2 million electric customers in eight counties.

[7] Moody's Analytics (2021, November) Forecast Risks. Precis U.S. Macro. Volume 26 Number 8.

Within PSE's service area, demand growth is uneven. Most economic growth is driven by high-tech, information technology, or retail (including online retail). Supporting industries like leisure and hospitality employment are also growing. Job growth is concentrated in King County, which accounts for the largest share of the system electric sales demand today. Other counties are growing, but typically at lower magnitudes, and have added fewer jobs.

We used the following forecast assumptions in the 2023 Electric Report base electric demand forecast:

- We expect an inflow of 898,000 new residents (by birth or migration) to increase the local area population to 5.33 million by 2045, for an average annual growth rate of 0.88 percent. This growth rate is slightly lower than the 2021 IRP forecast, which projected an average annual population growth of 0.9 percent that would have resulted in 5.13 million electric service area residents by 2045.
- We expect employment to grow at an average annual rate of 0.46 percent between 2024 and 2045, smaller than the 0.6 percent annual growth rate forecasted in the 2021 IRP.
- We expect local employers to create about 205,681 total jobs between 2024 and 2045, mainly driven by growth in the commercial sector, compared to about 310,000 jobs forecasted in the 2021 IRP.
- We expect manufacturing employment to decline by 0.32 percent annually between 2024–2050 due to outsourcing manufacturing processes to lower wages or less expensive states or countries and the continuing trend of capital investments that increase productivity.

Table 6.12 shows the population and employment forecasts for PSE's electric service area.

Table 6.12: Population and Employment Growth, Electric Service Counties (1,000s)

Model Driver	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Population	4,436	4,716	4,938	5,136	5,334	0.88
Employment	2,215	2,291	2,340	2,380	2,421	0.46

5.2. Weather

In this 2023 Electric Report, PSE incorporated Climate Change temperatures from three climate models to calculate the normal temperatures for the base energy demand forecast and the design peak temperature for the base peak demand forecast. Section 2 Climate Change of this chapter and Appendix F: Demand Forecasting Models discuss more details of how we created this forecast.

➔ Appendix F: Demand Forecasting Models discusses more details of how we created this forecast.

5.3. Electric Vehicles

The energy consulting firm Guidehouse created an EV forecast for PSE in late 2021. This EV forecast includes two recent pieces of legislation: the Zero Emission Vehicles law of 2020 and the Clean Fuel Standard law of 2021. The forecast assumes 95,000 EVs on the road in PSE's service area in 2024, including light-, medium-, and heavy-duty vehicles. This forecast will increase to 1,147,000 EVs in 2045. Annual energy sales from new electric vehicles total 183,000 MWh in 2024 and 4,815,000 MWh in 2045.

We assumed that 74 percent of the charging from new EVs would be at residential locations, while the remaining 26 percent would be at commercial sites. This percentage changes during the forecast period as charging at commercial locations becomes more widely available. This percentage also changes as more medium- and heavy-duty electric vehicles become available and cost-effective, resulting in 35 percent of EVs charging on residential accounts and 65 percent charging on commercial accounts in 2045. Electric vehicles, especially medium- and heavy-duty models, are an emerging technology; thus, we anticipate we will revise this forecast on an ongoing basis.

The additional demand from electric vehicles grows to a 19 percent share of total peak demand by 2045 before including the cost-effective DSR identified in the 2023 Electric Report. Figure 6.15 shows the December evening peak demand, and Figure 6.16 shows the annual average energy demand from new electric vehicles. Figure 6.17 shows the forecast of electric vehicles as a percent of all vehicles purchased in the PSE service territory.

Guidehouse also created high and low EV forecasts for PSE in late 2021. The consulting firm created the high and low EV scenarios representing the 90th and 10th percentile. Figures 6.15 and 6.16 show the high and low electric vehicle energy and peak forecasts used in the stochastic scenarios.

Figure 6.15: Electric Vehicle Average Energy Demand from New Vehicles (aMW)
Base, High, and Low

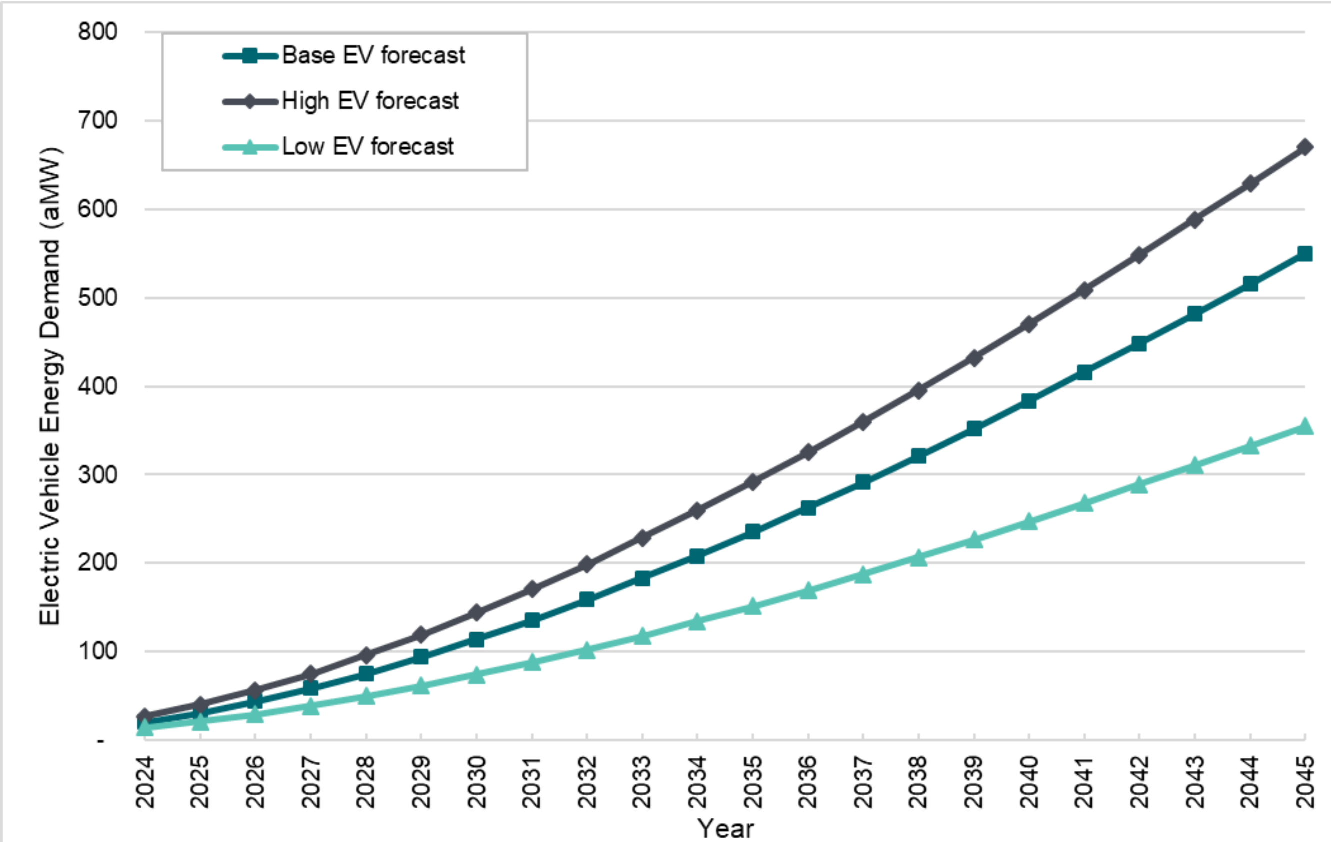


Figure 6.16: Electric Vehicle Peak Demand from New Vehicles (MW)
Base, High, and Low

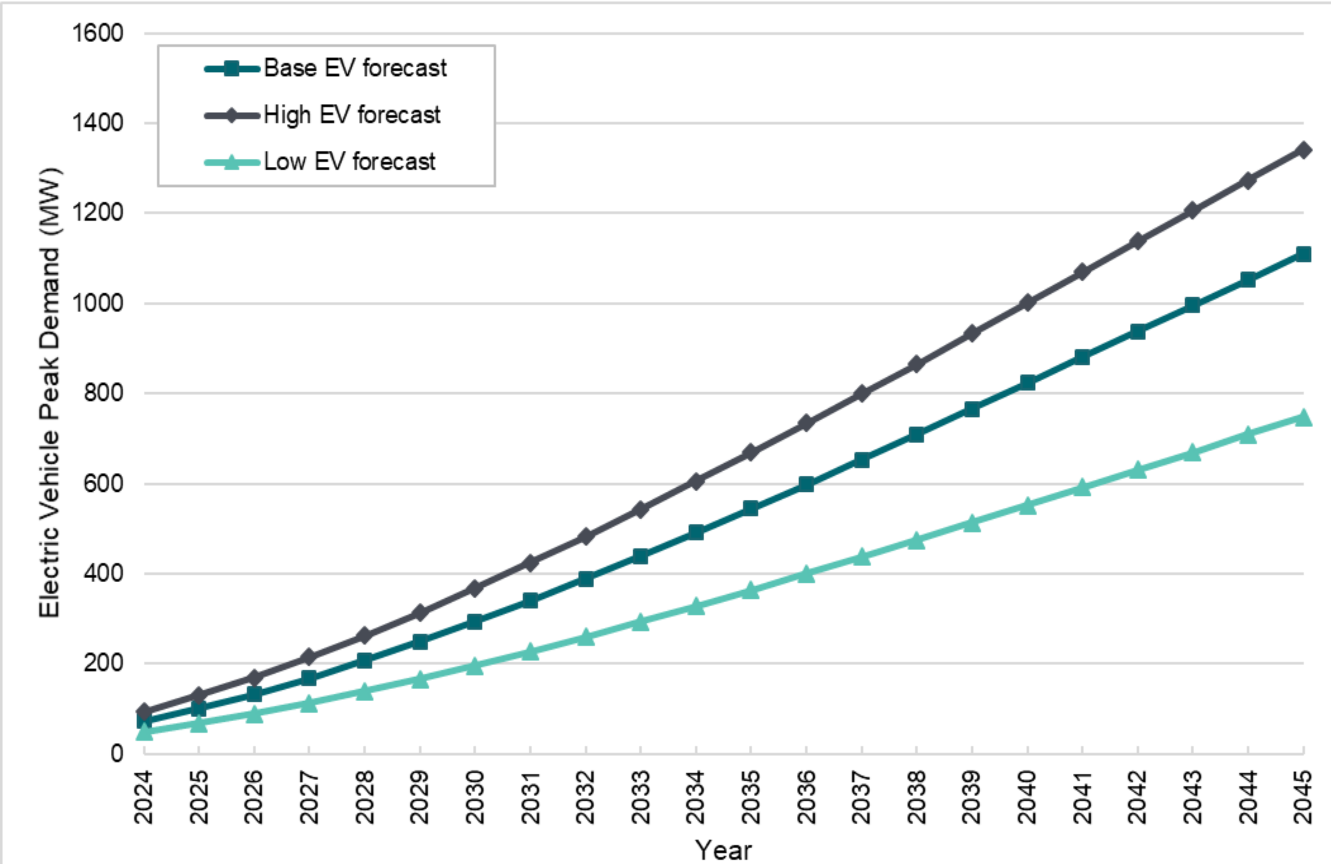
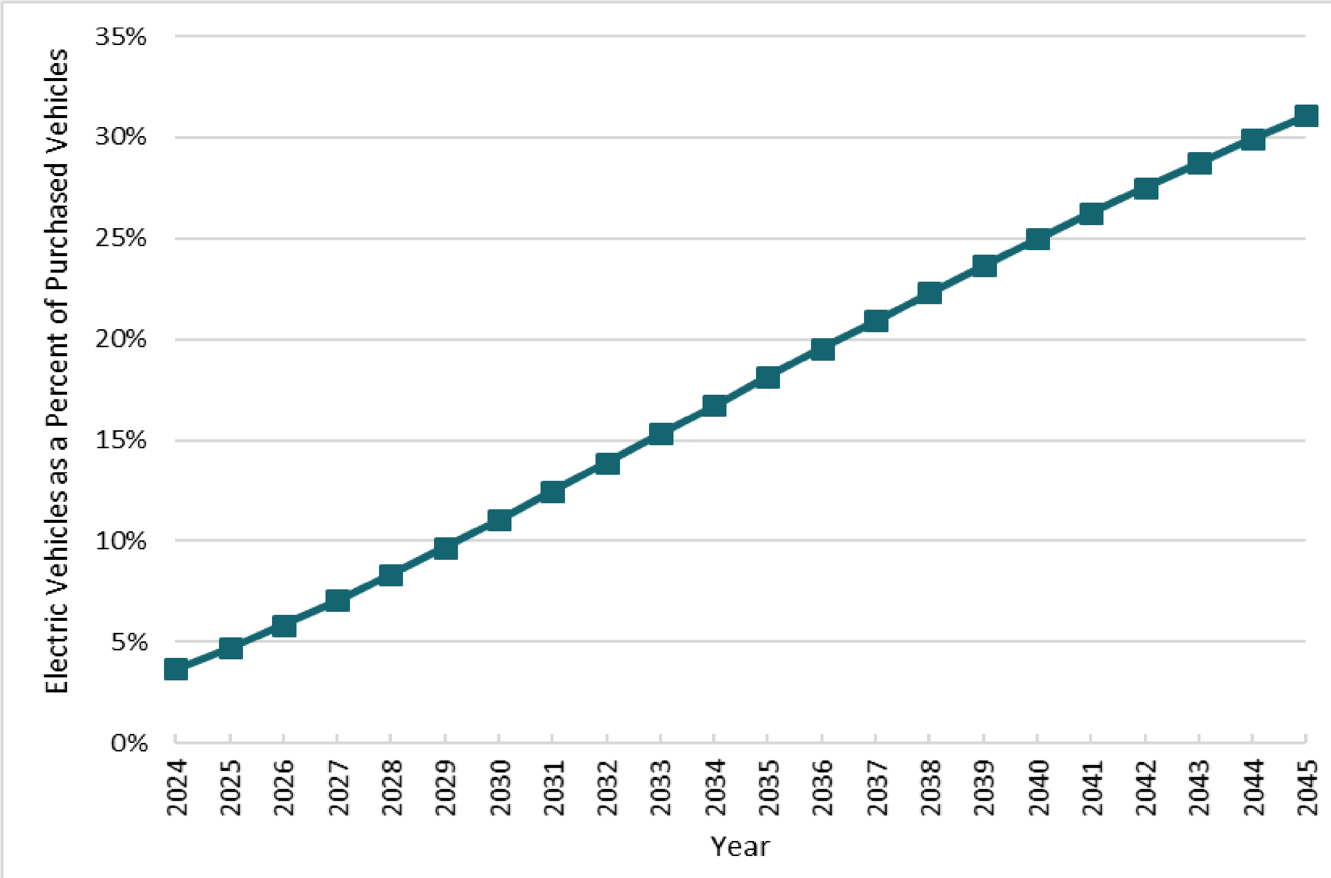


Figure 6.17: Electric Vehicles as a Percent of Purchased Vehicles



5.4. COVID-19 Impacts

After 2022, we made no explicit COVID-19 or remote work adjustments above and beyond the effects of the economic forecast incorporated into the demand forecast using the macroeconomic variables. The result is 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. There exists a great deal of uncertainty around the steady state level of residential and commercial usage once behaviors developed during the pandemic settle.

We performed stochastic simulations that varied the economic forecast around this base forecast. These included simulations with better and worse economic outcomes. Since the 2023 Electric Report determines the resource need starting in 2024, the stochastic simulations show alternative ways the pandemic could resolve in the future.

5.5. Loss Factors

The electric loss factor is 7.8 percent. The loss factors we assumed in the demand forecast are system-wide average losses during normal operations for the past two to three years.

5.6. Block Load Additions

Beyond typical economic change, the demand forecast also considers known major demand additions and deletions that we would not account for through typical demand growth in the forecast. Most of these additions are from major infrastructure projects. These additions to the forecast are called block loads, and they use the information provided by PSE's system planners or major accounts. The adjustments to non-transport customers will add 85.6 MW of connected demand by 2025 for the electric system. We included these block loads in the commercial class, and King County has most of the additions.

5.7. Schedule Switching

In addition to block loads, PSE accounts for customers switching rate schedules. Customers who purchase their own electricity are called transport customers, and they rely on PSE for distribution services. In this 2023 Electric Report, we removed transport customers from the forecast before determining supply-side resource needs because PSE is not responsible for acquiring supply resources for electric transport customers.

5.8. Interruptible Demand

Puget Sound Energy has 151 electric interruptible customers; six are commercial and industrial customers, and 145 are schools. The school contracts limit the time of day when energy can be curtailed. The other customers represent 12 MW of coincident peak demand. In this 2023 Electric Report, we accounted for the 12 MW of demand that is interruptible from these customers

5.9. Retail Rates

We included retail energy prices — what customers pay for energy — as explanatory variables in the demand forecast models because they affect customer choices about the efficiency level of newly acquired appliances and how they are used — the energy source used to power them. The retail rate forecasts draw on information obtained from internal and external sources.

5.10. Distributed Generation

We did not include distributed generation, including customer-level generation via solar panels, in the demand forecast after 2023; we captured this energy production in the 2023 Electric Report modeling process as a demand-side resource. We include a description in Appendix E: Conservation Potential Assessment and Demand Response Assessment. .

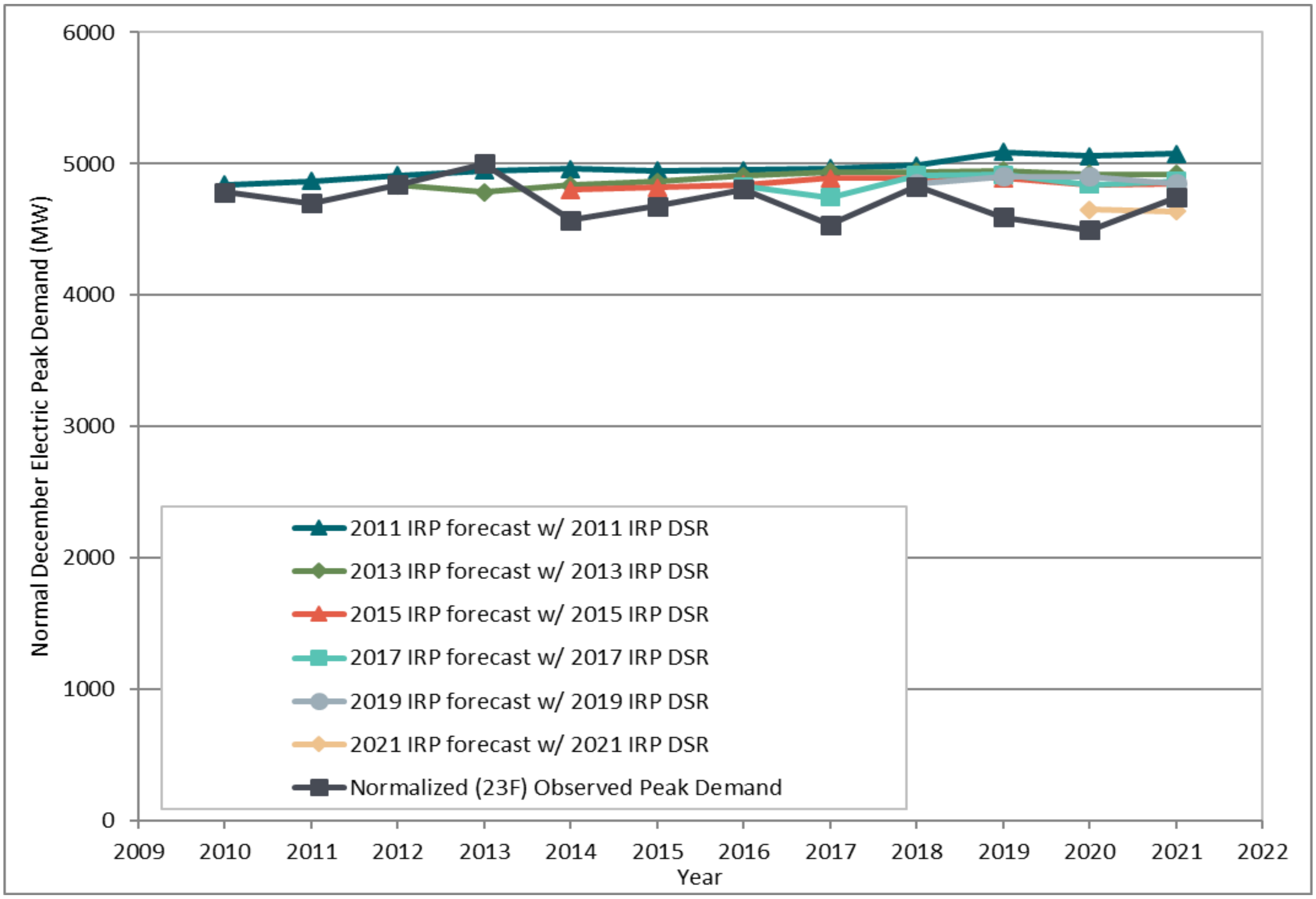
6. Previous Demand Forecasts

The following section compares actual peak demand to previous IRP forecasts. This section also identifies reasons prior forecasts may be off from current weather-normalized actual peaks.

6.1. IRP Peak Demand Forecasts Compared to Actual Peaks

Figure 6.18 compares 2011, 2013, 2015, 2017, 2019,[8] and 2021 IRPs' base peak demand forecasts after additional DSR with normalized[9] actual observations. We noted that the normalized actual observations account for peak hourly temperature, monthly HDDs, and the day of the week and time of day of the actual peak. We present the percent difference of normalized actual values compared to each IRP forecast for each year in Table 6.12.

Figure 6.18: Observed Normalized Electric December Peak Demand Compared to Previous IRP forecasts



8 A formal IRP was not filed by PSE in 2019. On October 28, 2019, the Washington Utilities and Transportation Commission Staff filed a Petition for Exemption from WAC 480-100-238 pursuant to WAC 480-07-100 until December 31, 2020. On November 7, 2019 the WUTC held an Open Meeting concerning this matter and subsequently issued Order 2, exempting PSE (and other investor owned utilities in Washington) from WAC 480-100-238. Pursuant to Order 2, PSE filed an IRP Progress Report in 2019.

9 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.

Table 6.12: Weather Normalized December Electric Peak Demand and Difference from Previous IRP Forecasts

Year	2011 (%)	2013 (%)	2015 (%)	2017 (%)	2019[8] (%)	2021 (%)
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	-
2020	12.6	9.5	7.7	7.7	9.1	3.5
2021	7.1	3.8	2.2	2.6	2.8	-2.2

6.1.1. Reasons for Forecast Variance

As explained throughout this chapter, we based the IRP peak demand forecasts on forecasts of key demand drivers, including expected economic and demographic behavior, DSR, customer usage, and weather. When these forecasts diverge from observed actual behavior, so does the IRP forecast. As forecasts age, assumptions and conditions may change. Because of these changes, we expect older predictions to be farther off from observed actuals than more recent forecasts. We explain these differences in the next section.

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. We pushed out a complete recovery with each successive forecast as the U.S. economy failed to bounce back to its previous state year after year. The charts below compare Moody's forecasts of U.S. housing starts and population growth that we incorporated in the 2011 IRP through the 2019 IRP 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. Puget Sound Energy now uses county population forecasts sourced from Washington's ESD to forecast the population in PSE's service area. We included Moody's forecast of housing starts and population from May 2020 and Nov 2021 in Figures 6.19 and 6.20 for comparison.

Additionally, while the Moody's forecast used in the 2019 IRP did predict a softening of the economy in 2020, it did not forecast the magnitude of the effects of the COVID-19 pandemic. Therefore, Moody's forecasts used before the 2021 IRP have likely overestimated economic growth in 2020, 2021, and 2022. The pandemic's repercussions on the economy and energy demand will likely be unknown during this reporting cycle.

Figure 6.19: Moody's Forecasts of U.S. Housing Starts Compared to Actual U.S. Housing Starts

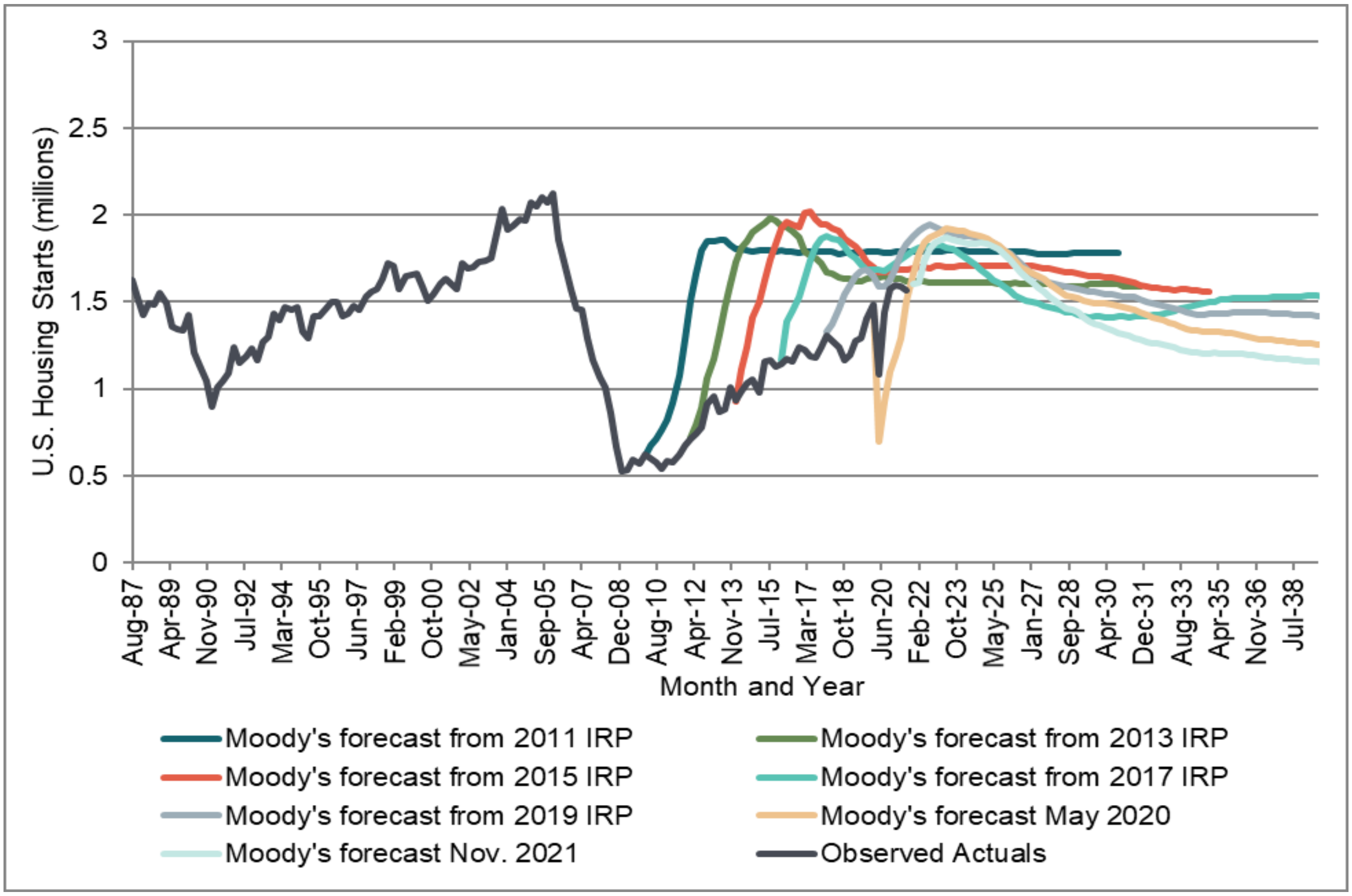
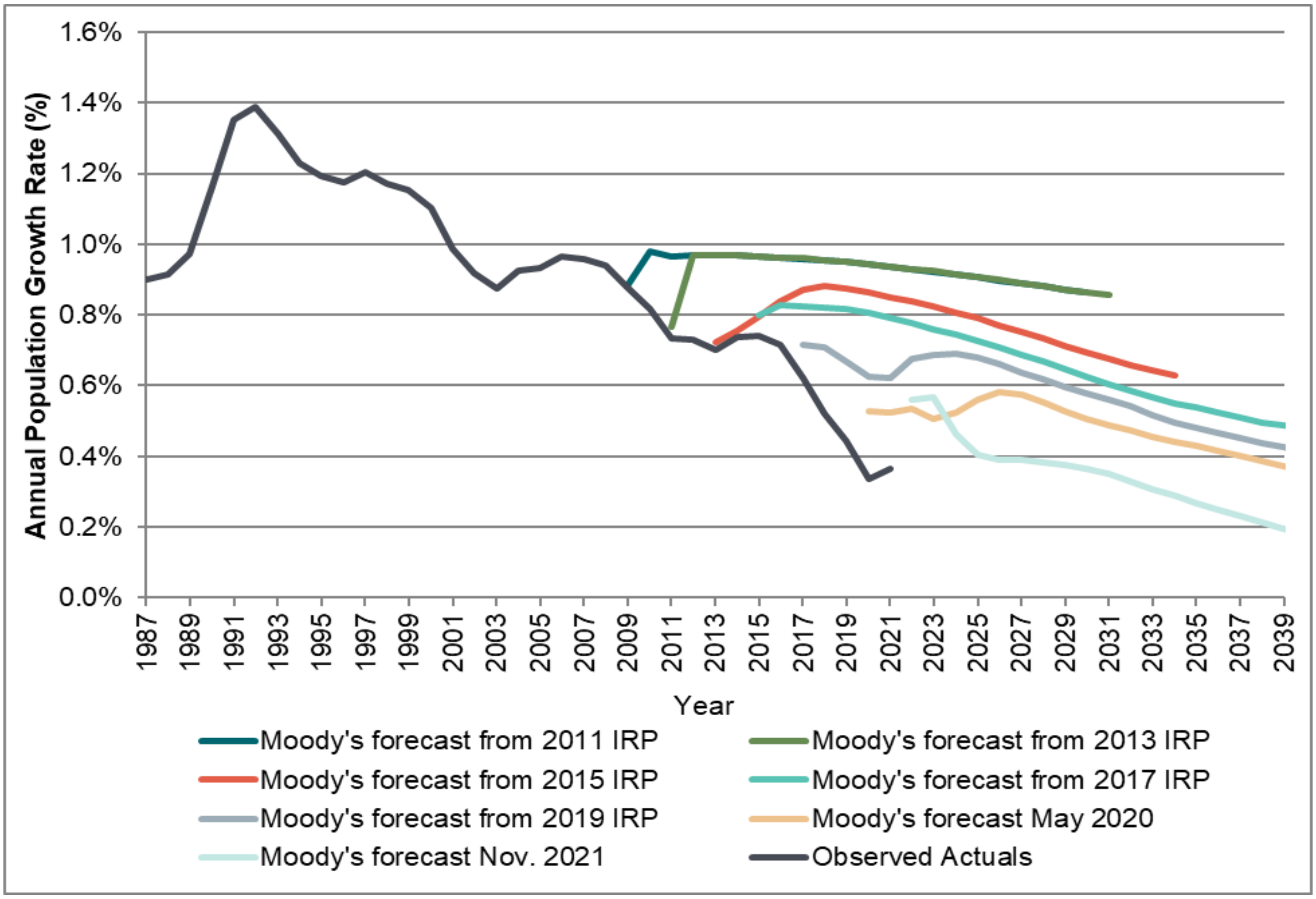


Figure 6.20: Moody's Forecasts of U.S. Population Growth Compared to Actual U.S. Population Growth



Demand-side Resources and Customer Usage

For the comparison in Figure 6.18 of weather-normalized peak observations to the IRP peak demand forecasts after additional DSR, we assumed the forecasted DSR was implemented. However, consumers can adopt energy-efficient technologies above and beyond what utility-sponsored DSR programs and building codes and standards incentivize. This consumer behavior leads to more actual DSR than we forecasted. The DSR programs can also change over time. In later IRPs, we can choose programs that were not cost-effective in the past but we now deem cost-effective. This situation can make an older forecast outdated, the DSR forecast too low, and the load forecast after additional DSR too high.

Also, the Global Settlement from the 2013 General Rate Case (GRC) PSE accelerates electric DSR by 5 percent yearly. We did not consider this additional DSR in comparing IRP forecasts with normalized actuals.

Normal Weather Changes

Normal weather assumptions change from forecast to forecast. We updated the normal weather assumption for the 2011 IRP to the 2021 IRP by rolling off two older years of temperature data and incorporating two new years of temperature data into the 30-year average. Over time, normal heating degree days have been declining, and the forecast of energy demand with normal weather has changed. In this 2023 Electric Report, we incorporated climate change into the normal definition, which altered the 2023 Electric Report base demand forecasts.

Additionally, over time our customers' weather sensitivity has been changing. As consumers implement energy efficiency measures, customers use less energy at a given temperature, including 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, 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 will likely differ from use 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. We included Jefferson County usage in the electric peak demand forecast in the 2011 IRP. Therefore, when comparing that forecast to today's actuals, we expect that forecast to be higher than the actual peak demand.