Demand Forecasts

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Demand forecasts are an estimate of how much energy customers will use in the future. When demand forecasts are compared with an assessment of the company's existing resources, the gap between the two identifies "resource need."

1. Overview

The F2012 IRP Base Demand Forecast for electric loads shows lower load levels throughout the forecast horizon than the demand forecasts used in the 2011 IRP. This is due to the loss of Jefferson County in 2013, lagging economic, housing, and employment recoveries, and higher short-term unemployment rates.

The F2012 Base Demand Forecast for gas also has lower load levels for most of the forecast period than those used in the 2011 IRP, catching up only in the last few years. This is also due to lagging recovery in the single-family housing market and sluggish labor market recovery. Since gas load is primarily heat-based, it is relatively less affected by economic conditions and exhibited slightly greater resilience between forecasts than the electric load.

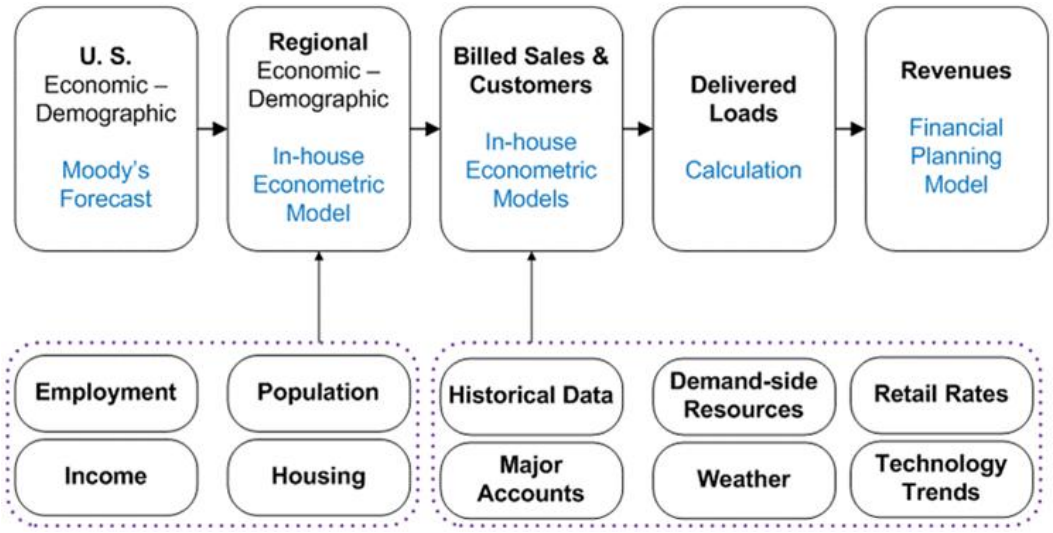
NOTE: The load forecasts that appear in the IRP often do not match the load forecasts presented in rate cases or during acquisition discussions. There are two reasons for this. First, the IRP analysis takes 12 to 18 months to complete, and load forecasts are so central to the analysis that they are one of the first inputs we need to develop. By the time the IRP is completed, PSE will have updated the load forecast, and the most current forecast will always be used in rate cases or when making acquisitions. Second, the IRP demand forecast does not include an off-set for demand-side resources (since the IRP is used to

determine cost-effective levels of these resources), and most other load forecasts published by PSE do include DSR.

2. Methodology

The demand forecast PSE develops for the IRP is an estimate of energy sales, customer counts, and peak demand over a 20-year period. These estimates are designed for use in long-term planning for resources and delivery systems. The 20-year horizon helps us anticipate needs so we can develop timely responses. Updates based on the most current information are used in developing near-term annual revenue forecasts and operational plans.

Figure H-1
PSE Load Forecasting Process: Electric and Gas



Source of Local Data: Washington State Employment Security Department, Bureau of Economic Analysis, Bureau of Labor Statistics, Office of Financial Management (Washington). The Puget Sound Economic Forecaster, Washington State Economic and Revenue Forecast Council

In the forecast models, electricity and gas are assumed as inputs into the production of various economic activities. For residential customers, typical energy uses include space heating, water heating, lighting, cooking, refrigeration, dish washing, laundry washing,

televisions, computers, and various other plug loads. Commercial and industrial customers use energy for production processes, space heating, ventilation, and air conditioning (HVAC), lighting, computers, and other office equipment.

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 are modeled separately using variables specific to their usage patterns.

- Electric customer classes include residential, commercial, industrial, streetlights, resale, and transportation.
- Gas customer classes include firm (residential, commercial, industrial, commercial large volume, and industrial large volume), interruptible (commercial and industrial), and transportation (commercial firm, commercial interruptible, industrial firm, and industrial interruptible).

The following section provides a more detailed technical description of the four econometric methodologies used to forecast (a) billed energy sales and customer counts, (b) hourly distribution of electric loads, and (c) system peak loads for electricity and natural gas.

For the 2012 load forecast used in this IRP, the company updated our key forecast driver assumptions and re-estimated the main equations.

Electric and gas billed sales and customer counts

PSE estimated the following use-per-customer (UPC) and customer count equations using varied sample dates from within a historical monthly data series from January 1989 to December 2011, depending on sector or class and fuel type. The billed sales forecast is based on the estimated equations, normal weather assumptions, rate forecasts, and forecasts of various economic and demographic inputs.

The UPC and customer count equations are defined as follows:

$$UPC_{c,t} = f(UPC_{c,t(k)}, RR_{c,t(k)}, W_{c,t}, ED_{c,t(k)}, MD_m)$$
$$CC_{c,t} = f(CC_{c,t(k)}, ED_{c,t(k)}, MD_m)$$
$$MD_i = \begin{cases} 1, Month = i \\ 0, Month \neq i \end{cases} \quad i \in \{1,2,\square\ 12\}$$
$$t \in \{1,2,\square\ 12\}$$

$UPC_{c,t}$ = use (billed sales) per customer for class “c”, month “t”

$CC_{c,t}$ = customer counts for class “c”, month “t”

$\text{—}_{t(k)}$ = the subscript $t(k)$ denotes either a lag of “k” periods from “t” or a polynomial distributed lag form in “k” periods from month “t”

$RR_{c,t(k)}$ = effective real retail rates for class “c”

$W_{c,t}$ = class-appropriate weather variable; cycle-adjusted HDD/CDD using base temperatures of 65, 60, 45, 35 for HDD and 65 and 75 for CDD; cycle-adjusted HDDs/CDDs are created to fit consumption period implied by the class billing cycles

$ED_{c,t(k)}$ = class-appropriate economic and demographic variables; variables include income, household size, population, employment levels or growth, and building permits

MD_i = monthly dummy variable that is 1 when the month is equal to “i”, and zero otherwise for “i” from 1 to 12

UPC is forecast at a class level using several explanatory variables including weather, retail rates, monthly effects, and various economic and demographic variables such as income, household size, and employment levels. Some of the variables, such as retail rates and economic variables, are added to the equation in a lagged, or polynomial lagged form to account for both short-term and long-term effects of changes in these variables on energy consumption. Finally, we use a lagged form of the dependent variable in many of the UPC equations. This lagged form could be as simple as a one month lag, or could be a more sophisticated time-series model, such as an ARIMA(p,q) model. This imposes a realistic covariant structure to the forecast equation.

Similar to UPC, PSE forecasts the customer count equations on a class level using several explanatory variables such as household population, total employment, manufacturing employment, or the retail rate. Some of the variables are also implemented in a lagged or polynomial distributed lag form to allow the impact of the variable to vary with time. Many of the customer equations use monthly growth as the dependent variable, rather than totals, to more accurately measure the impact of economic and demographic variables on growth, and to allow the forecast to grow from the last recorded actual value.

We generate customer forecasts by county by estimating an equation relating customer counts by class and county to population or employment levels in that county. Once the customer counts for each county are estimated, adjustments are made proportionally so that the total of all customer counts is scaled to the original service area forecast.

The billed sales forecast for each customer class is the product of the class UPC forecast and the forecasted number of customers in that class, as defined below.

$$Billed\ Sales_{c,t} = UPC_{c,t} \times CC_{c,t}$$

The billed sales and customer forecast is adjusted for discrete additions and subtractions not accounted for in the forecast equations, such as major changes in energy usage by large customers. These adjustments may also include fuel and schedule switching by large customers. Total billed sales in a given month are calculated as the sum of the billed sales across all customer classes:

$$Total\ Billed\ Sales_t = \sum_c Billed\ Sales_{c,t}$$

PSE estimates total system delivered loads by distributing monthly billed sales into each billing cycle for the month, then allocating the billing cycle sales into the appropriate calendar months using degree days as weights, and adjusting each delivered sales for losses from transmission and distribution. This approach also enables computation of the unbilled sales each month.

Hourly electric demand profile

Because temporarily storing large amounts of electricity is costly, the minute-by-minute interaction between electricity production and consumption is very important. For this reason, and for purposes of analyzing the effectiveness of different electric generating resources, an hourly profile of PSE electric demand is required.

We use our hourly (8,760 hours) load profile of electric demand for the IRP, for our power cost calculation, and for other AURORA analyses. The estimated hourly distribution is built using statistical models relating actual observed temperatures, recent load data, and the latest customer counts.

Data

PSE developed a representative distribution of hourly temperatures based on data from Jan. 1, 1950 to Dec. 31, 2011. Actual hourly delivered electric loads between Jan. 1, 1994 and Dec. 31, 2011 were used to develop the statistical relationship between temperatures and loads for estimating hourly electric demand based on a representative distribution of hourly temperatures.

Methodology for distribution of hourly temperatures

The above temperature data were sorted and ranked to provide two separate data sets: For each year, a ranking of hourly temperatures by month, coldest to warmest, over 60 years was used to calculate average monthly temperature. A ranking of the times when these temperatures occurred, by month, coldest to warmest, was averaged to provide an expected time of occurrence. Next PSE found the hours most likely to have the coldest temperatures (based on observed averages of coldest-to-warmest hour times) and matched them with average coldest-to-warmest temperatures by month. Sorting this information into a traditional time series then provided a representative hourly profile of temperature.

Methodology for hourly distribution of load

For the time period Jan. 1, 1994 to Dec. 31, 2011, PSE used the statistical hourly regression equation:

$$\hat{L}_h = \vec{\beta}_{1,d} \cdot DD_d + \alpha_1 L_{h-1} + \alpha_2 \left(\frac{L_{h-2} + L_{h-3} + L_{h-4}}{3} \right) + \left(\vec{\alpha}_{3,m} T_h + \vec{\alpha}_{4,m} T_h^2 \right) + \vec{\beta}_{2,d} Hol + \alpha_5 P^{(1)}(h)$$

for h from one to 24 to calculate load shape from the representative hourly temperature profile. This means that a separate equation is estimated for each hour of the day.

$\hat{L}_h =$ Estimated hourly load at hour "h"

L_h = Load at hour "h"

L_{h-k} = Load "k" hours before hour "h"

T_h = Temperature at time "h"

T_h^2 = Squared hourly temperature at time "h"

$P^{(1)}(h)$ = 1st degree polynomial

Hol = NERC holiday dummy variables

All Greek letters again denote coefficient vectors.

Peak load forecasting

Peak load forecasts are developed using econometric equations that relate observed monthly peak loads to weather-sensitive delivered loads for both residential and nonresidential sectors. They account for deviations of actual peak hour temperature from normal peak temperature for the month, day of the week effects, and unique weather events such as a cold snap or an El Nino season.

Electric peak hour load forecast

Based on the forecast delivered loads, we use hourly regressions to estimate a set of monthly peak loads for the system based on three specific design temperatures: "Normal," "Power Supply Operations" (PSO), and "Extreme." The "Normal" peak is based on the average temperature at the monthly peak during a historical time period, currently 30 years. The winter peaks are set at the highest Normal peak, which is currently the December peak of 23 degrees Fahrenheit. We estimated the PSO peak design temperatures to have a 1-in-20 year probability of occurring. These temperatures were established by examining the minimum temperature of each winter month. A function relating the monthly minimum temperature and the return probability was established. The analysis revealed the following design temperatures: 15 degrees Fahrenheit for January and February, 17 degrees Fahrenheit for November, and 13 degrees Fahrenheit for December. Finally, the "Extreme" peak design temperatures are estimated at 13 degrees Fahrenheit for all winter months.

Weather dependent loads are accounted for by the major peak load forecast explanatory variable, the difference between actual peak hour temperature and the average monthly temperature multiplied by system loads. The equations allow the impact of peak design temperature on peak loads to vary by month. This permits the weather-dependent effects of system delivered loads on peak demand to vary by season. The sample period for this forecast utilized monthly data from January 1991 to December 2011.

In addition to the effect of temperature, the peak load is estimated by accounting for the effects of several other variables. A variable is used to account for the portion of monthly system delivered loads which are non-weather dependent and affect the peak load. The peak forecast also depends on a number of other variables such as a dummy variable accounting for large customer changes, a day of the week variable, and a cold snap variable to account for when the peak day occurs following several cold days. The functional form of the electric peak hour equation is

$$PkMW_t = \overset{\sqcup}{\alpha}_{1,m} S_t + \overset{\sqcup}{\alpha}_{2,m} \chi_1 \cdot \Delta T \cdot S_t + \beta_{1,d} DD_d + \alpha_{3,m} CSnp + \delta_1 \cdot LT_t$$

where:

$$\chi_1 = \begin{cases} 1, & Month \neq 7,8 \\ 0, & Month = 7,8 \end{cases}$$

$$\chi_2 = \begin{cases} 1, & Month = 7,8 \\ 0, & Month \neq 7,8 \end{cases}$$

$PkMW_t$ = monthly system peak hour load in MW

S_t = system delivered loads in the month in aMW

ΔT = deviation of actual peak hour temperature from monthly normal temperature

DD_d = day of the week dummy

$CSnp$ = 1 if the minimum temperature the day before peak day is less than 32 degrees Fahrenheit

LT_d = late hour of peak dummy

χ_1, χ_2 = dummy variables used to put special emphasis on summer months to reflect growing summer peaks.

To clarify the equation above, when forecasting we allow the coefficients for loads to vary by month to reflect the seasonal pattern of usage. However, in order to conserve space, we have employed vector notation. The Greek letters α_m, β_d, and δ_d are used to denote coefficient vectors; α_m denotes a monthly coefficient vector (12 coefficients), β_d denotes a coefficient for the day of the week (seven coefficients), and δ_d denotes a coefficient for morning or evening peak. The difference between α_m and α_m is that all values in α_m are constant, whereas α_m can have unique values by month. That is to say, all "January" months will have the same coefficient. There are also two indicator variables that account for air conditioning load, to reflect the growing summer usage caused by increased saturation of air conditioning.

Gas peak day load forecast

Similar to the electric peaks, the gas peak day is assumed to be a function of weather-sensitive delivered sales, the deviation of actual peak day average temperature from monthly normal average temperature, and other weather events. The following equation used monthly data from October 1993 to June 2011 to represent peak day firm requirements:

$$PkDThm_t = \breve{\alpha}_{1,m} Fr_t + \breve{\alpha}_{2,m} \Delta T_g \cdot Fr_t + \alpha_{3,m} EN + \alpha_{4,m} M_t + \alpha_{5,m} Sum + \alpha_{6,m} Csnp$$

where:

$$Win = \begin{cases} 1, & Month = 1,2,11,12 \\ 0, & Month \neq 1,2,11,12 \end{cases}$$

$$Smr = \begin{cases} 1, & Month = 6,7,8,9 \\ 0, & Month \neq 6,7,8,9 \end{cases}$$

$PkDThm_t$ = monthly system gas peak day load in dekatherms

Fr_t = monthly delivered loads by firm customers

ΔT_g = deviation of actual gas peak day average daily temperature from monthly normal temperature

EN = dummy for when El Nino is present during the winter

M_t = dummy variable for month of the year

$CSnp$ = indicator variable for when the peak occurred within a cold snap period lasting more than one day, multiplied by the minimum temperatures for the day

As before, the Greek letters are coefficient vectors as defined in the Electric Peak section above.

This formula uses forecasted billed sales as an explanatory variable, and the estimated model weighs this variable heavily in terms of significance. Therefore, the peak-day equation will follow a similar trend as that of the billed sales forecast with minor deviations based on the impact of other explanatory variables. An advantage of this process is the ability to

account for the effects of conservation on peak loads by using billed sales with conservation included as the forecast variable. It also helps estimate the contribution of distinct customer classes to peak loads.

The design peak day used in the gas peak day forecast is a 52 heating degree day (13 degrees Fahrenheit average temperature for the day), based on the costs and benefits of meeting a higher or lower design day temperature. In the 2003 LCP, PSE changed the gas supply peak day planning standard from 55 heating degree days (HDD), which is equivalent to 10 degrees Fahrenheit or a coldest day on record standard, to 51 HDD, which is equivalent to 14 degrees Fahrenheit or a coldest day in 20 years standard. The Washington Utilities and Transportation Commission (WUTC) responded to the 2003 plan with an acceptance letter directing PSE to “analyze” the benefits and costs of this change and to “defend” the new planning standard in the 2005 LCP.

As discussed in Appendix I of the 2005 LCP, PSE completed a detailed, stochastic cost-benefit analysis that considered both the value customers place on reliability of service and the incremental costs of the resources necessary to provide that reliability at various temperatures. This analysis determined that it would be appropriate to increase our planning standard from 51 HDD (14 degrees Fahrenheit) to 52 HDD (13 degrees Fahrenheit). PSE’s gas planning standard relies on the value our natural gas customers attribute to reliability and covers 98 percent of historical peak events. As such, it is unique to our customer base, our service territory, and the chosen form of energy. Thus, we use projected delivered loads by class and this design temperature to estimate gas peak day load.

3. Key Assumptions

Economic activity has a significant effect on energy demand. During this 2-year planning cycle, it has been particularly challenging to develop assumptions about national and regional economic trends due to continued uncertainty throughout the period. While the economy continued to slowly recover through this period, “false starts” in 2010 and 2011, as well as downside risks from the “fiscal cliff,” European recession, and Asian slowdown in 2012 had a dampening effect on confidence and growth.

Economic growth

Because the Puget Sound region is a major commercial and manufacturing center with strong links to the national and state economies, the performance of these economies has a direct affect on the industries in our service territory and the businesses that support them. For this reason, PSE’s service area 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 this information. Ultimately, PSE forecasts economic and demographic conditions for each county in the service territory using a system of econometric equations that relates national to regional economic conditions.

National economic outlook

For the purpose of creating the baseline load forecast used in this IRP, PSE used the February 2012 Moody’s Analytics U.S. Macroeconomic Forecast. Moody’s pushed out its expectations for recovery and predicted that it would gain strong ground only by 2014, when real GDP was expected to be rising at nearly 4 percent and unemployment would finally be below 7% and on a sustainable path downward. At the time Moody’s expected the Federal Reserve to begin tightening monetary policy in late 2013 and normalize it by 2015 with inflation near its target level.

Risks to this economic forecast were the deepening of the European financial crisis with adverse impacts on U.S. exports; spending cuts and expiration of the payroll tax holiday and unemployment insurance benefits; corrosion of purchasing power due to elevated oil prices with further increases possible due to tensions in the Middle East; and an uncertain housing market recovery due to shadow inventory; and spending cuts by both state and local governments. Some of these risks have abated since this forecast was created. The housing

recovery has gained traction, the fiscal cliff has been avoided in the short term, and Middle East issues have not precipitated an oil price crisis. However, fiscal challenges in the near- and long-term future remain. Europe's financial problems are still not over and a potential breakup of the European Union is still a downside risk, and U.S. – Iran tensions have the potential to create upward pressure on oil prices in the future.

Globally, the dollar was expected to strengthen against the euro and yen in the near term, and to depreciate against the yuan but not without resistance from China. In the long term, the dollar was expected to depreciate only slightly due to the lack of better investment alternatives.

Regional economic outlook

PSE's regional economic and demographic forecast is prepared internally using econometric models whose primary input is a macroeconomic forecast of the United States and historical economic data of counties in PSE's service area. Although the Puget Sound region has its own economic and demographic characteristics, it is part of a national and global economy and its pattern of growth is highly correlated with that of the rest of the nation. As mentioned above, the baseline analysis in the current IRP is drawn from a regional economic forecast derived using the February 2012 Moody's Analytics U.S. Macroeconomic Forecast, with other regional sources providing input and context where appropriate. The assumptions from this regional forecast were used to create the forecast scenario identified as the 2013 IRP Base Demand Forecast.

According to PSE's regional forecast model base case, the projected employment in the electric service territory is expected to grow at an annual rate of 1.4 percent between 2012 and 2033, compared to the prior 20-year historical rate of 1.1 percent. The main factor contributing to the slightly faster long-term growth in employment is recovery from the effects of the latest recession that is built into the forecast sample. Overall long-term regional growth is driven by existence of a diversified group of employers such as Microsoft, REI, Boeing, Starbucks and the like, but is moderated by expectations that the Boeing Company's strong historical employment growth will not necessarily persist into the future. While manufacturing employment showed a greater than expected improvement in the short run due to the strong performance of the aerospace industry, it is expected on average to decline annually by 0.4 percent between 2012 and 2033 in this scenario due to increases in productivity through capital investment in this sector. The base case forecast projects that local employers will create more than 596,000 jobs between 2012 and 2033 and that an

inflow of more than 1 million new residents will increase the population of PSE's electric service territory to almost 4.8 million by 2033.

Multiple alternate scenarios were developed for the analysis, six based on business cycle variations ("Cyclical" Alternate Lows and Highs) and two based on population growth variations ("Structural" Alternate Low and High). The "Structural" Alternate Low is also referred to as the 2013 IRP Low Demand Forecast. Similarly, the "Structural" Alternate High is also known as the 2013 IRP High Demand Forecast.

The "Cyclical" Alternate Low and High scenarios were developed using varied assumptions provided by Moody's Analytics. "Cyclical" is used as a descriptor in this case because Moody's alternative scenarios are based in large part on assumptions about near-term business cycles in the national economy. To derive the Cyclical Low 1 assumptions, PSE calculated the ratio between Moody's baseline and pessimistic outlooks for each major national economic variable (such as total U.S. employment). These ratios were then used to scale down the equivalent regional variable (such as regional employment). Then these sets of revised variables were used to calculate the Cyclical Low 1 load forecast scenario. A similar approach was taken to calculate the Cyclical High 1 load forecast scenarios, with a ratio calculated between Moody's optimistic and baseline projections for each economic variable. The other scenarios, all of which followed the same development structure, include Cyclical Low 2, Cyclical Low 3, Cyclical Low 4, and Cyclical Low 5, and are essentially variations on the base case that consider delayed economic recovery in some form.

"Structural" Alternate Low and High scenarios were developed using variations on long-term population growth provided by the Washington state Office of Financial Management (OFM). "Structural" is used in this case as a descriptor to indicate that the scenarios are based on alternative assumptions of long-term regional population growth, rather than business cycles. The methodology used to derive these scenarios was to calculate the high and low to base population ratios for the OFM data; the ratios were then used to scale PSE's long-term forecast of population derived from the in-house economic-demographic models.
Other economic variables such as total employment, unemployment rate, etc., were also appropriately scaled, maintaining their relative relationship to the population in the base case. The final set of variables related to both the high and low population estimates were then used to calculate the Structural Low load forecast and the Structural High load forecast.

Energy prices

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

Electricity

PSE projects that between 2012 and 2033, nominal retail electric rates will experience on average a compounded annual growth rate of 3.2 percent with a range of 0.4 to 4.4 percent in the forecast period. In the near term, the retail price forecast assumes rate increases resulting from PSE's General Rate Cases and from Power Cost Only Rate Cases. For long-term retail rates, each usage class's annual retail rate growth is estimated using sources such as EIA's Annual Energy Outlook, NWPPC's Power Plan and Seattle's consumer price index based on PSE's regional economic and demographic forecast. In addition, Puget Sound Energy recognizes that forecasting from within a business cycle has inherent risks, and that the prevailing trend, whether growth or decline, should be moderated in the long-run portion of the forecast. This can be accomplished by understanding which aspects of the load forecast parameters are most anomalous and modifying those aspects appropriately for the long-run forecast.

Natural gas

PSE expects the rise in nominal retail gas rates to be slightly higher than the long-term rate of inflation, approximately 2.4 percent per year over the next 20 years. Two components make up gas retail rates: the cost of gas and the cost of distribution, known as the distribution margin. The near-term forecast of gas rates includes PSE's purchased gas adjustment and General Rate Case considerations. Forecasted gas costs reflect Kiodex gas prices for the 2012-2016 period and inflation projections beyond that. The distribution margin is based on PSE's projection for the near term and inflation projections for the longer term.

Other assumptions

Weather

The billed sales forecast is based on normal weather, defined as the average monthly weather using a historical time period of 30 years, ending in 2011.

Loss factors

Based on updated analysis, the electric loss factor was adjusted from 6.8 to 6.9, while the gas loss factor remains at 0.8 percent.

Major accounts

The 2013 IRP Base Forecast took into account major load additions and declines beyond typical economic change, using information from account executives covering major customers. The overall impact was approximately 5-10 aMW over the next 10 years.

4. Electric and Gas Demand Forecasts

Demand forecasts starting in 2012 serve as the basis for establishing resource need in this IRP. The charts and tables included here incorporate demand-side resources implemented through December 2013 (primarily energy efficiency), but do not include anticipated additional demand-side resources thereafter. PSE analyzed the scenarios described below in order to capture a range of possible economic futures.

2013 IRP Base Demand Forecast. This scenario assumes that the U.S. economy grows over time at an average annual real GDP growth rate of 2.3 percent from 2012 to 2033, with no major shocks or disruptions. It projects employment in the electric service territory to grow at an annual rate of 1.4 percent, and manufacturing employment growth to decline by an annual rate of 0.4 percent. With a faster rate of growth than the 15-year historical rate of 0.8 percent, it projects that local employers will create more than 596,000 jobs between 2012 and 2033, and that the inflow of more than 1,050,000 new residents will increase the population of our service territory to almost 4.8 million.

2013 IRP Low Demand Forecast. This scenario assumes lower long-term population growth and determines the subsequent effect on customer growth and other parameters. Final population in 2033 is approximately 9 percent lower than the 2013 IRP Base Demand Forecast, leading to substantially reduced levels of employment and total personal income.

2013 IRP High Demand Forecast. This scenario assumes higher long-term population growth and determines the subsequent effect on customer growth and other parameters. Final population in 2033 is just over 10 percent higher than the 2013 IRP Base Demand Forecast, leading to substantially increased levels of employment and total personal income.

Figure H-2

Forecast of Electric Service Area Household Growth Rates

Forecast of Electric Service Area Household Growth Rates							
Scenario	2014	2015	2016	2017	2018	2019	2020
2013 IRP Base Demand Forecast	1.3%	1.2%	1.1%	1.2%	1.4%	1.4%	1.4%
2013 IRP High Demand Forecast	2.6%	2.9%	2.0%	1.4%	1.9%	1.8%	1.9%
2013 IRP Low Demand Forecast	1.1%	-0.7%	0.4%	1.2%	0.6%	1.1%	1.0%

Figure H-3

Forecast of Electric Service Area Unemployment rates

Forecast of Electric Service Area Unemployment Rates							
Scenario	2014	2015	2016	2017	2018	2019	2020
2013 IRP Base Demand Forecast	6.2%	5.3%	4.7%	4.6%	4.5%	4.4%	4.2%
2013 IRP High Demand Forecast	6.0%	5.1%	4.5%	4.3%	4.3%	4.1%	4.0%
2013 IRP Low Demand Forecast	6.5%	5.5%	5.0%	4.8%	4.7%	4.6%	4.5%

Electric forecasts

Figures H-4 and H-5 show electric load and peak growth forecasts for all three scenarios over the first 10 years of the planning horizon. Highlights with reference to the 2013 IRP Base Demand Forecast are discussed on the following pages.

Figure H-4
Electric Load Growth for Three Scenarios
Load (MWh), Gross of Losses, Net of Station Service, 2012-2013 DSR Only

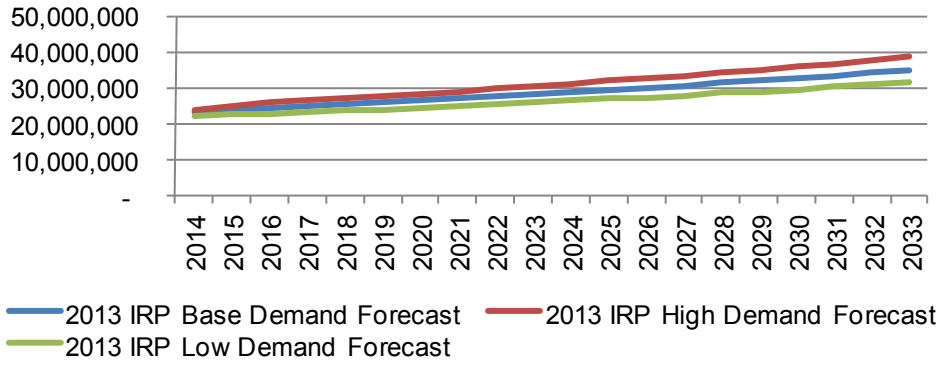
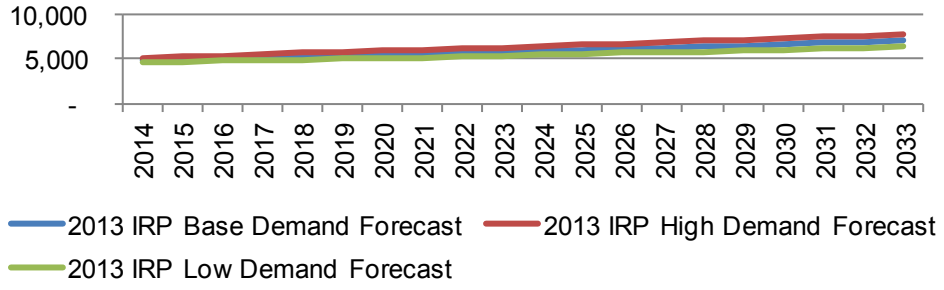


Figure H-5
Electric Peak Load Growth for Three Scenarios
Hourly Annual Peak (23 Degrees, MWh), Gross of Losses, Net of Station Service, 2012 -2013 DSR Only



Electric forecast highlights – 2013 IRP Base Demand Forecast

1. System. Average electric firm loads are expected to grow at an average annual rate of 2 percent per year, from 2,437 aMW in 2012 to 3,719 aMW by 2033.

The average annual growth rate is projected to be approximately 1.7 percent between 2012 and 2016 due to reduced near-term economic growth with higher short-term unemployment rates and a lagging housing recovery. The long-term growth rate of sales returns to slightly above 2 percent per year for the remainder of the period, 2017-2033.

2. Residential. Residential load as a percentage of firm load is expected to decline from 51 percent in 2012 to 46 percent in 2033.

Slower growth in residential loads is caused by several factors: a projected increase in the rate of construction of multifamily housing, which uses less energy per customer compared to single-family housing; the use of more efficient appliances; and the expectation that new single-family homes are likely to use gas for space and water heating. These factors are expected to combine to create a relatively flat average residential use per customer during the forecast period. In terms of customer growth, the residential sector is expected to see a lower percentage growth compared to the commercial sector. However, the absolute number of customer additions would still be the largest in the residential sector in the forecast period. Multi-family residential housing units, which have a lower number of persons per household than single-family units, are expected to be constructed at a higher rate in the future. Since multi-family units tend to have a lower average number of persons per household, this leads to a customer growth rate that is higher than the population growth rate.

3. Commercial and industrial. Commercial loads are expected to increase as a percentage of firm load from 43 percent in 2012 to 50 percent in 2033. This is partly due to the shifts in residential energy use described above, but it is also due to the way the commercial sector tends to adopt of energy efficient technologies early. Most conservation is captured in early years, leaving less savings available for capture in later years, so the load grows. The commercial sector is expected to experience the strongest average customer growth among major customer classes in the forecast period, however, in absolute terms, it will add fewer customers than the residential sector. Industrial loads are forecasted to

decline as a percentage of firm load from 6 percent in 2012 to 3 percent in 2033, in line with expectations for declining average customer growth of about 0.4 percent in the period.

4. Peak. Peak hourly loads for electric are expected to grow by 1.9 percent per year between 2012 to 2033 to 7,113 MW from 4,837 MW, nearly keeping pace with the growth in billed energy.

Peak load growth in this forecast tracks closer to energy load growth than it did in the 2011 IRP due to a change in methodology. The 2011 IRP forecast used percentages of customer classes to model peak growth, while this IRP forecast uses the total load. This resulted in patterns of overall energy load growth being closer to peak load growth.

In general, the 2013 IRP Base Forecast of energy load is lower than the 2011 IRP forecast by about 349 aMW by 2033. This is because the 2012 forecast begins with a lower starting point due to the impacts of the recession.

APPENDIX H – DEMAND FORECASTS

The following tables summarize electric demand forecast results.

Figure H-6

Electric Load Forecast Scenarios

Load (aMW)								
Scenario	2014	2015	2016	2017	2023	2028	2033	AARG
2013 IRP Base Demand Forecast	2,644	2,718	2,796	2,849	3,210	3,587	3,995	2.2%
2013 IRP High Demand Forecast	2,734	2,856	2,955	3,023	3,468	3,920	4,409	2.5%
2013 IRP Low Demand Forecast	2,554	2,571	2,628	2,671	2,955	3,264	3,592	1.8%

Figure H-7

Electric Load by Class, 2013 IRP Base Demand Forecast

Load (aMW) by class from 2013 IRP Base Demand Forecast								
	2014	2015	2016	2017	2023	2028	2033	AARG
Total	2,644	2,718	2,796	2,849	3,210	3,587	3,995	2.2%
Residential	1,228	1,263	1,299	1,321	1,469	1,605	1,726	1.8%
Commercial	1,078	1,112	1,150	1,180	1,376	1,593	1,855	2.9%
Industrial	144	144	142	140	130	126	121	-0.9%
Other	12	12	12	12	14	15	17	2.0%
Losses	182	188	193	197	221	247	276	2.2%

Figure H-8

Electric Average Annual Customers by Class, 2013 IRP Base Demand Forecast

Average Annual Customers by Class from 2013 IRP Base Demand Forecast								
	2014	2015	2016	2017	2023	2028	2033	AARG
Total	1,102,073	1,123,497	1,145,710	1,167,667	1,295,135	1,404,168	1,515,902	1.7%
Residential	974,424	993,636	1,013,383	1,032,760	1,143,994	1,237,431	1,331,928	1.7%
Commercial	120,498	122,619	124,989	127,453	142,872	157,705	174,059	2.0%
Industrial	3,518	3,507	3,496	3,484	3,401	3,329	3,257	-0.4%
Other	3,633	3,734	3,842	3,971	4,868	5,703	6,658	3.2%

Figure H-9

Annual Electric Peak (MW), 2013 IRP Base Demand Forecast

Annual Electric Peak (MW) from 2013 IRP Base Demand Forecast								
	2014	2015	2016	2017	2023	2028	2033	AARG
Normal	4,922	5,039	5,150	5,244	5,846	6,439	7,113	2.0%
Extreme	5,419	5,549	5,672	5,776	6,444	7,102	7,849	2.0%

Figure H-10

Electric Use per Customer, 2013 IRP Base Demand Forecast

Use Per Customer (MWh) from 2013 IRP Base Demand Forecast								
	2014	2015	2016	2017	2023	2028	2033	AARG
Residential	11.040	11.134	11.229	11.201	11.247	11.362	11.349	0.1%
Commercial	78.342	79.427	80.595	81.081	84.365	88.498	93.353	0.9%
Industrial	358.604	359.182	355.486	351.575	334.014	330.669	326.514	-0.5%

Gas forecasts

Figures H-11 and H-12 map the gas forecasts for all three scenarios to show load and peak day forecasts, excluding demand-side resources, for the first 10 years of the planning horizon. Highlights are discussed on the following pages.

Figure H-11
Annual Gas Load Forecast Scenarios, 2010-2019
Load (Therms), Gross of Losses, 2012-2013 DSR Only

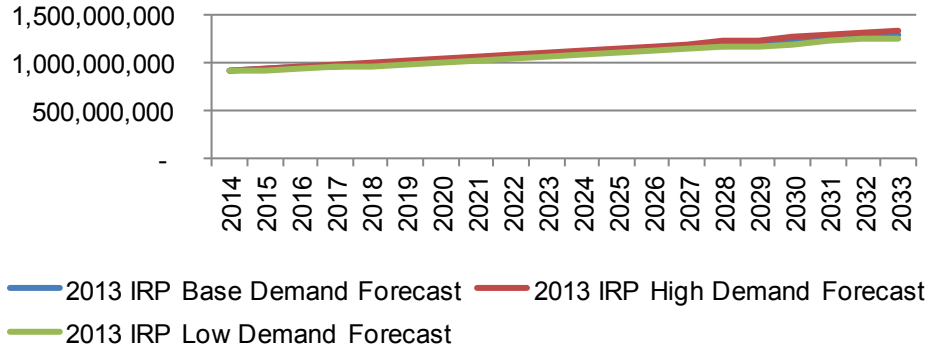
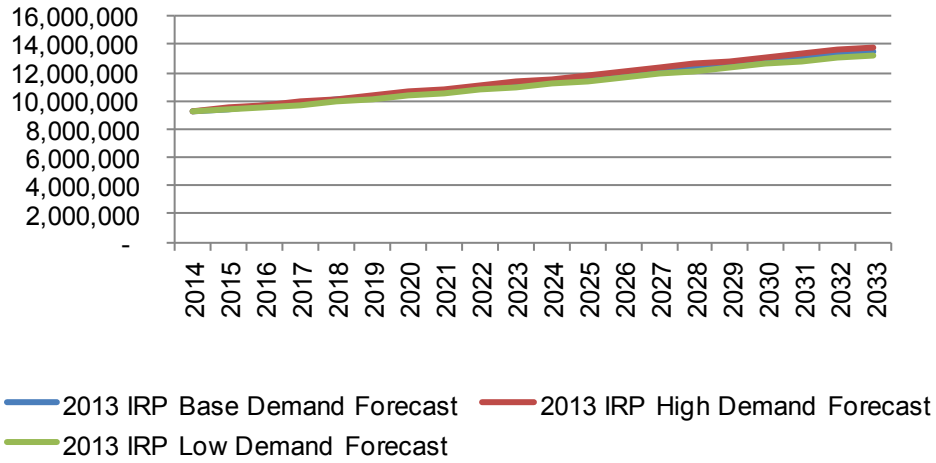


Figure H-12
Firm Gas Peak-Day Forecast Scenarios 2010-2019
Daily Annual Peak (13 Degrees, Therms), Gross of Losses, 2012-2013 DSR Only



Gas forecast highlights – 2013 IRP Base Demand Forecast

1. System. Natural gas load is expected to grow at an average rate of 1.4 percent per year between 2012 and 2033, from 1.1 billion therms in 2012 to just under 1.5 billion therms in 2033.

For 2012-2016, we expect a slightly lower growth rate in gas load of 1.3 percent due to lower household formation stemming from high unemployment and a weak housing market in the near term; recovery begins to pick up pace starting 2016. Given persistently lower natural gas prices which translate into lower gas retail rates in the forecast period, along with normalized economic conditions, load is expected to grow at a long-term rate of 2.3 percent per year.

While overall sales volume will increase over the long term, some sectors (industrial, interruptible, and transportation) are expected to decline slightly, continuing more than a decade-long trend of slowing manufacturing employment. The gas customer count is expected to increase at a rate of 2.2 percent per year between 2012 and 2033, reaching approximately 1.2 million by the end of the forecast period.

2. Residential. Residential accounts are expected to increase at a rate of approximately 2.2 percent per year from 2012 to 2033, and to represent 93.3 percent of our total customer base in 2033, up 0.8 percent from 92.6 percent in 2012.

In the residential class, a slight decline in use per customer caused by more efficient equipment, a projected increase in multi-family housing and energy efficiency is expected to be offset by a steady increase in the number of customers due to population growth and conversion from electric to gas.

While the number of potential conversion customers is expected to decline, this is expected to be partially offset by increasing penetration of gas into multi-family buildings (townhomes and condominiums) and new single-family homes.

3. Commercial and industrial. Commercial sector accounts are expected to grow at an average annual rate of approximately 1.8 percent per year during the next two decades, and to account for roughly 6.5 percent of the overall customer base in 2033. Similar to the electric side, industrial gas customers also decline over the forecast period on

account of a declining manufacturing base. Over approximately a 20-year period, the industrial load's share of the system load declines form 0.3 percent to 0.2 percent.

4. Peak. Peak day firm gas requirements are expected to increase at an average rate of 1.9 percent per year over approximately the next 20 years, from 8.9 million therms in 2012 to 13.5 million therms in 2033.

Gas peak-day growth rates are slightly higher than those for total load because faster growth is predicted for the weather-sensitive residential and commercial sectors. The primary drivers of peak growth across all sectors are an expanding customer base and changes in use per customer. Rising base-loads are contributing to peak demand because gas is increasingly being used for purposes other than heating (such as cooking, clothes drying, and fireplaces). This effect is slightly offset by higher appliance and home efficiencies, and by the increasing use of gas in multi-family housing, where per-customer use is lower.

Compared to the gas peak day forecast from the 2011 IRP, this forecast is lower during the 20-year forecast. A reduced customer growth forecast, as well as a slightly lower use per customer due to weaker economic conditions resulted in a lower residential billed sales forecast, which is the primary driver of the peak-day forecast.

The following tables summarize gas demand forecast results.

Figure H-13
Gas Load without Transport

Load (1,000 Therms), without Transport								
Scenario	2014	2015	2016	2017	2023	2028	2033	AARG
2013 IRP Base Demand Forecast	917,389	932,182	952,010	965,135	1,080,673	1,191,601	1,290,187	1.8%
2013 IRP High Demand Forecast	924,845	944,627	966,838	981,529	1,105,637	1,223,056	1,326,689	1.9%
2013 IRP Low Demand Forecast	910,019	920,668	938,743	950,448	1,058,047	1,162,713	1,255,926	1.7%

Figure H-14

Gas Customers by Class, 2013 IRP Base Demand Forecast

Load (1,000 Therms) by Class from 2013 IRP Base Demand Forecast								
	2014	2015	2016	2017	2023	2028	2033	AARG
Total	1,159,749	1,173,254	1,192,823	1,204,464	1,313,113	1,418,811	1,510,884	1.4%
Residential	563,388	574,100	588,485	598,716	682,779	759,150	835,260	2.1%
Commercial	258,670	263,151	269,046	273,097	307,981	344,073	370,634	1.9%
Industrial	29,248	28,902	28,588	28,022	25,794	24,198	20,153	-1.9%
Interruptible	58,743	58,571	58,275	57,579	55,474	54,648	53,819	-0.5%
Transport	240,421	239,143	238,887	237,415	230,580	225,392	218,932	-0.5%
Losses	9,278	9,386	9,543	9,636	10,505	11,350	12,087	1.4%

Figure H-15

Average Annual Gas Customers by Class, 2013 IRP Base Demand Forecast

Average Annual Gas Customers by Class from 2013 IRP Base Demand Forecast								
	2014	2015	2016	2017	2023	2028	2033	AARG
Total	786,664	802,457	820,369	839,644	968,499	1,083,751	1,206,349	2.3%
Residential	728,257	743,186	760,156	778479.0068	901041.3326	1010157.819	1125945.399	2.3%
Commercial	55494.42474	56388.09293	57359.46489	58340.11168	64786.20821	71034.72225	77947.7624	1.8%
Industrial	2378.567337	2360.247851	2341.990724	2323.901217	2218.166903	2133.686582	2052.2899	-0.8%
Interruptible	331.8497874	319.7952523	308.6304672	298.344579	250.218944	222.1483774	200.9786862	-2.6%
Transport	203	203	203	203	203	203	203	0.0%

Figure H-16

Gas Use per Customer, 2013 IRP Base Demand Forecast

Use Per Customer (Therms) from 2013 IRP Base Demand Forecast								
	2014	2015	2016	2017	2023	2028	2033	AARG
Residential	774	772	774	769	758	752	742	-0.2%
Commercial	4,661	4,667	4,691	4,681	4,754	4,844	4,755	0.1%
Industrial	12,296	12,245	12,207	12,058	11,629	11,341	9,820	-1.2%