INTEGRATED RESOURCE PLAN

IDAHO POWER®
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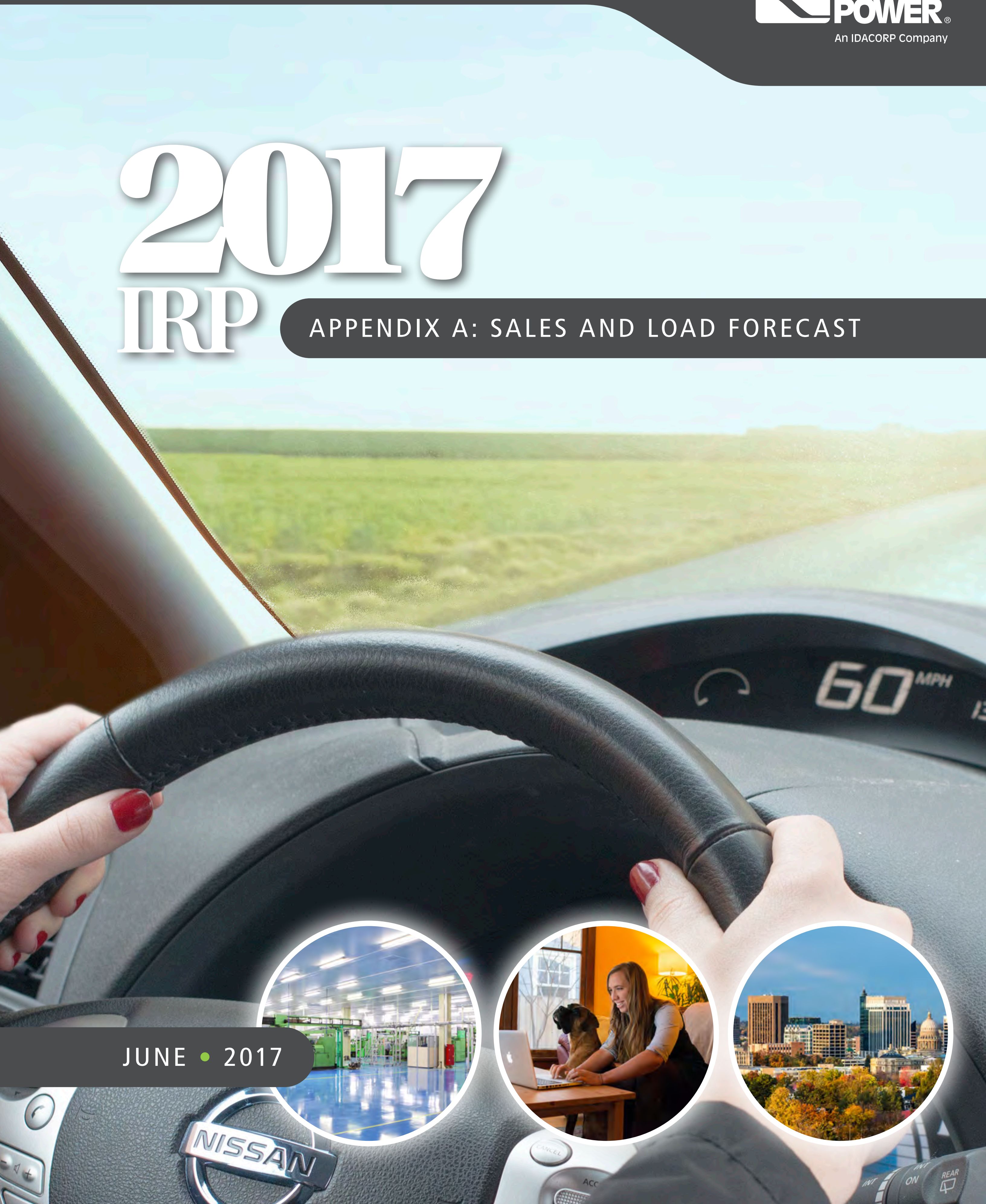
2017 IRP

APPENDIX A: SALES AND LOAD FORECAST



JUNE • 2017

SAFE HARBOR STATEMENT

2017 IRP

APPENDIX A: SALES AND LOAD FORECAST

ACKNOWLEDGEMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan (IRP) every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the 2017 IRP. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

It takes approximately one year for a dedicated team of individuals at Idaho Power to prepare the IRP. The Idaho Power team is comprised of individuals that represent many departments within the company. The IRP team members are responsible for preparing forecasts, working with the advisory council and the public, and performing all the analyses necessary to prepare the resource plan.

Idaho Power looks forward to continuing the resource planning process with customers, public-interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at idahopower.com.

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INTRODUCTION

Idaho Power has prepared *Appendix A—Sales and Load Forecast* as part of the *2017 Integrated Resource Plan* (IRP). Appendix A includes details on the energy sales and load forecast of future demand for electricity within the company's service area. The above-mentioned forecast covers a 20-year period from 2017 through 2036.

The expected-case monthly average load forecast is Idaho Power's estimate of the most probable outcome for load growth during the planning. To account for inherent uncertainty and variability, four additional load forecasts were prepared in addition to the expected-case—a low case, a 70th-percentile case, a 90th-percentile case, and a high case, all of which are described in more detail in this report. The high and low economic growth scenarios provide a range of possible load growths over the planning period due to variable economic, demographic, and other non-weather-related influences. Additional cases are developed around the 70th-percentile and 90th-percentile load forecast scenarios to assist Idaho Power in reviewing the resource requirements that would result from variable loads due to variable weather conditions for temperatures and rainfall. It is important to note that in the IRP resource planning process, Idaho Power uses the 70th-percentile load forecast to account for the risk associated with weather impacts on load.

In the expected-case scenario, Idaho Power's system load is forecast to increase to 2,142 average megawatts (aMW) by 2036 from 1,810 aMW in 2017, representing an average yearly growth rate of 0.9 percent over the 20-year planning period (2017–2036). In the more critical 70th-percentile load forecast used for resource planning, the system load is forecast to reach 2,193 aMW by 2036 (0.9% average annual growth)[1]. Additionally, the number of Idaho Power active retail customers is expected to increase from the December 2016 level of 533,400 customers to nearly 755,000 customers by year-end 2036 (see footnote 1).

For capacity planning purposes, it is forecasted that Idaho Power's system will grow to 4,641 megawatts (MW) in 2036 from the all-time system peak of 3,407 MW that occurred on Tuesday, July 2, 2013, at 4:00 p.m. Idaho Power's system peak increases at an average growth rate of 1.4 percent per year over the 20-year planning period (2017–2036).

The numerous external factors influencing the forecast are primarily economic and demographic in nature. Moody's Analytics serves as the primary provider for this data. The national, state, metropolitan service area (MSA), and county economic and demographic projections are tailored to Idaho Power's service area using an in-house economic database. Specific demographic projections are also developed for the service area from national and local census data.

[1] Recent company disclosures forecast load growth during the 2016 to 2035 planning period at 1.0 percent for average energy demand and 1.4 percent for peak-hour demand.

Additional data sources used to substantiate Moody's data include the Idaho Department of Labor, Woods & Poole, Construction Monitor, and Federal Reserve economic databases.

Economic growth assumptions influence several classes of service growth rates. The number of households in Idaho is projected to grow at an annual rate of 1.2 percent during the forecast period. The growth in the number of households within individual counties in Idaho Power's service area is projected to grow faster than the remainder of the state over the planning period. The number of households in the Boise –Nampa MSA is projected to grow even faster than the state of Idaho, at an annual rate of 1.6 percent during the forecast period. The Boise MSA (or the Treasure Valley) is an area that encompasses Ada, Boise, Canyon, Gem, and Owyhee counties in southwestern Idaho. In addition, the number of households, incomes, employment, economic output, real retail electricity prices, and customer consumption patterns are used to develop load projections.

In addition to the economic assumptions used to drive the expected-case forecast scenario, several assumptions were incorporated into the forecasts of the residential, commercial, industrial, and irrigation sectors. Further discussions of these assumptions are presented below.

Conservation influences on the load forecast, including Idaho Power energy efficiency demand-side management (DSM) programs, statutory programs, and non-programmatic trends in conservation, are included in the load forecasts of each sector. Idaho Power DSM programs are described in detail in Idaho Power's *Demand-Side Management 2016 Annual Report*, which is incorporated into this IRP document as Appendix B.

During the 20-year forecast horizon, major shifts in the electric utility industry (e.g., state and federal regulations and varying electricity prices) could influence the load forecast. In addition, the price and volatility of substitute fuels, such as natural gas, may also impact future demand for electricity. The high degree of uncertainty associated with such changes is reflected in the economic high and low load growth scenarios described previously. The alternative sales and load scenarios in *Appendix A—Sales and Load Forecast* were prepared under the assumption that Idaho Power's geographic service area remains unchanged during the planning period.

Data describing the historical and projected figures for the sales and load forecast are presented in Appendix A1 of this report.

2017 IRP Sales and Load Forecast

Average Load

The economic and demographic variables driving the 2017 forecast have the impact of increasing current annual sales levels throughout the planning period. The delay in the expected "robust lift-off" of the business cycle recovery process after the Great Recession in 2008 for the national and, to a lesser extent, service-area economy halted load growth post-recession through 2011. However, in 2012, the extended recovery process was evident, and on-balance stronger growth was exhibited in most economic drivers relative to recent history at that time. It is expected that economic conditions return to long-term fundamentals during the 2017 forecast period. Significant factors and considerations that influenced the outcome of the 2017 IRP load forecast include the following:

- The load forecast used for the 2017 IRP reflects a continuance of the recovery in the service-area economy following a severe recession in 2008 and 2009. As customer growth was at a near standstill until 2012, acceleration of in-migration and business investment resulted in renewed growth in the residential and commercial connections along with increased industrial activity. As of 2017, customer additions have approached sustainable growth rates experienced prior to the housing bubble (2000–2004) and are expected to continue.

- The electricity price forecast used to prepare the sales and load forecast in the 2017 IRP reflects the impact of additional plant investment and associated variable costs of integrating new resources identified in the 2015 IRP preferred portfolio Compared to the electricity price forecast used to prepare the 2015 IRP sales and load forecast, the 2017 IRP price forecast yields lower future prices. The retail prices are most evident after the first two years of the planning period and can impact the sales forecast positively, a consequence of the inverse relationship between electricity prices and electricity demand.

- There continues to be significant uncertainty associated with the industrial and special-contract sales forecasts due to the number of parties that contact Idaho Power expressing interest in locating operations within Idaho Power's service area, typically with an unknown magnitude of the energy and peak-demand requirements. Nonetheless, the expected load forecast reflects only those industrial customers that have made a sufficient and significant binding investment, indicating a commitment of the highest probability of locating in the service area. Therefore, the large numbers of prospective businesses that have indicated an interest in locating in Idaho Power's service area but have not made sufficient commitments are not included in the current sales and load forecast.

- Conservation impacts, including DSM energy efficiency programs and codes and standards, and other naturally occurring efficiencies are considered and integrated into the sales forecast. Impacts of demand response programs (on peak) are accounted for in the load and resource balance analysis within supply-side planning (i.e., are treated as a supply-side peaking resource). The amount of committed and implemented DSM programs for each month of the planning period is shown in the load and resource balance in *Appendix C—Technical Appendix*.

- The 2017 irrigation sales forecast is higher than the 2015 IRP forecast throughout the entire forecast period due to the significant trend toward more water-intensive crops, primarily alfalfa and corn, due to growth in the dairy industry. Also, farmers have put high-lift acreage back into production. Additionally, load increases have come from the conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers trying to reduce labor costs.

Peak-Hour Demands

As average demands as discussed in the preceding section are an integral component to the load forecast, so are the impact of the peak-hour demands on the system. The peak-hour forecasting regressions are expressed as a function of the sales forecast as well as the impact of peak-day temperatures. The peak forecast results and comparisons with previous forecasts differ for many reasons that include the following:

- The all-time system summer peak demand was 3,407 MW (recorded on Tuesday, July 2, 2013, at 4:00 p.m.). The system peak-hour load record was nearly matched on June 30, 2015, at 4:00 p.m., when the system peak reached 3,402 MW. Idaho Power's winter peak-hour load record is 2,527 MW, recorded on January 6, 2017, at 9:00 a.m. and matched the previous record peak dated December 10, 2009, at 8:00 a.m.

- The peak model develops peak-scenario impacts based on historical probabilities of peak-day temperatures at the 50th, 90th, and 95th percentiles of occurrence for each month of the year. The 95th percentile forecast of peak-hour demand is utilized for peak capacity planning purposes. These normal average peak-day temperature drivers are calculated over the 1986 to 2015 time period (the most recent 30 years).

- The 2017 IRP peak-demand forecast considers the impact of the current actualized committed and implemented energy efficiency DSM programs on peak demand.

OVERVIEW OF THE FORECAST

The sales and load forecast is constructed by developing a separate energy forecast for each of the major customer classes: residential, commercial, irrigation, industrial, and special contracts. In conjunction with this energy (or sales) forecast, an hour peak-load forecast was prepared. In addition, several probability cases were developed for the energy and peak forecasts. Assumptions for each of the individual categories, the peak hour impacts, and probabilistic case methodologies are described in greater detail in the following sections.

Forecast Probabilities

Load Forecasts Based on Weather Variability

The future demand for electricity by customers in Idaho Power's service area is represented by three load forecasts reflecting a range of load uncertainty due to weather. The expected-case average load forecast represents the most probable projection of system load growth during the planning period and is based on the most recent national, state, MSA, and county economic forecasts and the resulting derived economic forecast for Idaho Power's service area.

The expected-case average load forecast assumes median temperatures and median precipitation (i.e., there is a 50% chance loads will be higher or lower than the expected-case loads due to colder-than-median or hotter-than-median temperatures or wetter-than-median or drier-than-median precipitation). Since actual loads can vary significantly depending on weather conditions, alternative scenarios were developed that address load variability due to varying weather conditions.

For example, Idaho Power's maximum annual average load occurs when the highest recorded levels of heating degree days (HDD) are assumed in winter and the highest recorded levels of cooling and growing degree days (CDD and GDD) combined with the lowest recorded level of precipitation are assumed in summer. Conversely, the minimum annual average load occurs when the opposite of what is described above takes place. In the 70^{th}-percentile residential and commercial load forecasts, temperatures in each month were assumed to be at the 70^{th} percentile of HDD in wintertime and at the 70^{th} percentile of CDD in summertime. In the 70^{th}-percentile irrigation load forecast, GDD were assumed to be at the 70^{th} percentile and precipitation at the 30^{th} percentile, reflecting drier-than-median weather. The 90^{th}-percentile load forecast was similarly constructed.

For example, the median HDD in December from 1986 to 2015 (the most recent 30 years) was 1,029, at the Boise Weather Service office. The 70^{th}-percentile HDD is 1,060 and would be exceeded in 3 out of 10 years. The 90^{th}-percentile HDD is 1,170 and would be exceeded in 1 out of 10 years. As an example, for a single month, the 100^{th}-percentile HDD (the coldest December over the 30 years) is 1,449, which occurred in December 1990. This same concept was applied in each month throughout the year for the weather-sensitive customer classes: residential, commercial, and irrigation.

Since Idaho Power loads are highly dependent on weather, and the development of the above mentioned two scenarios allows the careful examination of load variability and how it may impact future resource requirements. It is important to understand that the probabilities associated with these forecasts apply to each month. This assumes temperatures and precipitation would maintain at the 70th-percentile or 90th-percentile level continuously, throughout the entire year. For Idaho Power to properly plan for future resource requirements, a similar methodology is needed for the hour of maximum demand for the year (referred to as peak demand). Table 1 summarizes the load scenarios prepared for the 2017 IRP.

Table 1. Average load and peak-demand forecast scenarios

Scenario	Weather Probability	Probability of Exceeding	Weather Driver
Forecasts of Average Load			
90th Percentile	90%	1 in 10 years	HDD, CDD, GDD, precipitation
70th Percentile	70%	3 in 10 years	HDD, CDD, GDD, precipitation
Expected Case	50%	1 in 2 years	HDD, CDD, GDD, precipitation
Forecasts of Peak Demand			
95th Percentile	95%	1 in 20 years	Peak-day temperatures
90th Percentile	90%	1 in 10 years	Peak-day temperatures
50th Percentile	50%	1 in 2 years	Peak-day temperatures

The analysis of resource requirements is based on the 70th-percentile average load forecast coupled with the 95th-percentile peak-demand forecast to provide a more adverse representation of the average load and peak demand to be considered. In other Idaho Power planning, such as the preparation of the financial forecast or the operating plan, the expected-case (50th percentile) average-load forecast and the 90th-percentile peak-demand forecast are typically used.

Load Forecasts Based on Economic Uncertainty

The expected-case load forecast is based on the most recent economic forecast for Idaho Power's service area and represents Idaho Power's most probable outcome for load growth during the planning period.

To provide risk assessment to economic uncertainty, two additional load forecasts for Idaho Power's service area were prepared based on the expected case forecast. The forecasts provide a range of possible load growth rates for the 2017 to 2036 planning period due to high and low economic and demographic conditions. The average growth rates for these high and low growth scenarios were derived from the historical distribution of one-year growth rates over the past 25 years (1992–2016).

Of the three scenarios 1) the expected forecast is the median growth path, 2) the standard deviation observed during the historical time period is used to estimate the dispersion around the expected-case scenario, and 3) the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1992–2016).

From the above methodology, two views of probable outcomes from the forecast scenarios—the probability of exceeding and the probability of occurrence—were developed and are reported in Table 2. The probability of exceeding the likelihood the actual load growth will be greater than the projected growth rate in the specified scenario. For example, over the next 20 years, there is a 10-percent probability the actual growth rate will exceed the growth rate projected in the high scenario; additionally, it can be inferred that for the stated periods there is an 80 percent probability the actual growth rate will fall between the low and high scenarios.

The second probability estimate, the probability of occurrence, indicates the likelihood the actual growth will be closer to the growth rate specified in that scenario than to the growth rate specified in any other scenario. For example, there is a 26-percent probability the actual growth rate will be closer to the high scenario than to any other forecast scenario for the entire 20-year planning horizon.

Table 2. Forecast probabilities

Probability of Exceeding				
Scenario	**1-year**	**5-year**	**10-year**	**20-year**
Low Growth	90%	90%	90%	90%
Expected Case	50%	50%	50%	50%
High Growth	10%	10%	10%	10%
Probability of Occurrence				
Scenario	**1-year**	**5-year**	**10-year**	**20-year**
Low Growth	26%	26%	26%	26%
Expected Case	48%	48%	48%	48%
High Growth	26%	26%	26%	26%

This probabilistic analysis was applied to Idaho Power's system load forecast. Its impact on the system load forecast is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts (including past sales to Astaris, Inc.) and on-system contracts (including past sales to Raft River Coop and the City of Weiser).

Results of Idaho Power's system load projections are reported in Table 3 and shown in Figure 1. The expected-case system load-forecast growth rate averages 0.9 percent per year over the 20-year planning period. The low scenario projects the system load will increase at an average rate of 0.4 percent per year throughout the forecast period. The high scenario projects a load growth of 1.3 percent per year. Idaho Power has experienced both the high- and low-growth rates in the past. These forecasts provide a range of projected growth rates that cover approximately 80 percent of the probable outcomes as measured by Idaho Power's historical experience.

Table 3. System load growth (aMW)

Growth	2017	2021	2026	2036	Annual Growth Rate 2017–2036
Low	1,748	1,765	1,810	1,891	0.4%
Expected	1,810	1,894	1,990	2,142	0.9%
High	1,835	1,968	2,111	2,351	1.3%

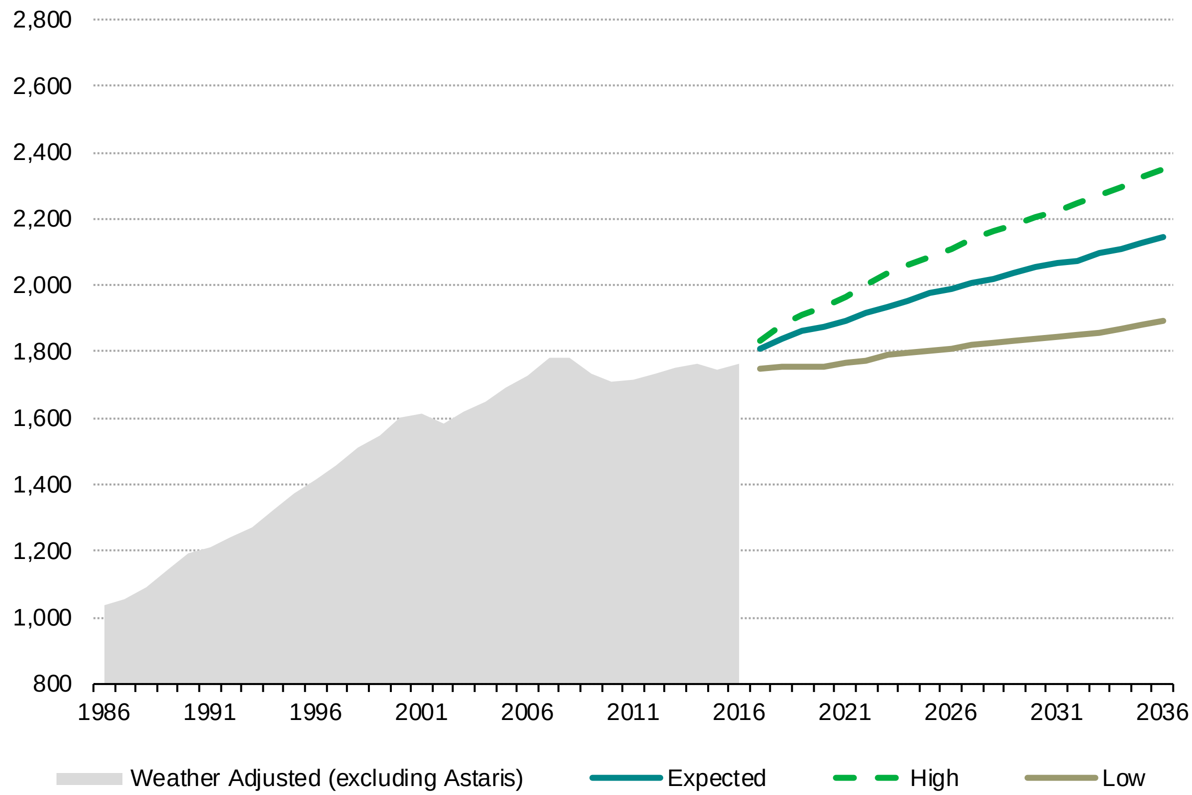

Figure 1. Forecast system load (aMW)

RESIDENTIAL

The expected-case residential load is forecast to increase from 594 aMW in 2017 to 747 aMW in 2036, an average annual compound growth rate of 1.2 percent. In the 70th-percentile scenario, the residential load is forecast to increase from 612 aMW in 2017 to 772 aMW in 2036, matching the expected-case residential growth rate. The residential load forecasts are reported in Table 4 and shown in Figure 2.

Table 4. Residential load growth (aMW)

Growth	2017	2021	2026	2036	Annual Growth Rate 2017–2036
90th Percentile	643	681	730	810	1.2%
70th Percentile	612	648	695	772	1.2%
Expected Case	594	628	673	747	1.2%

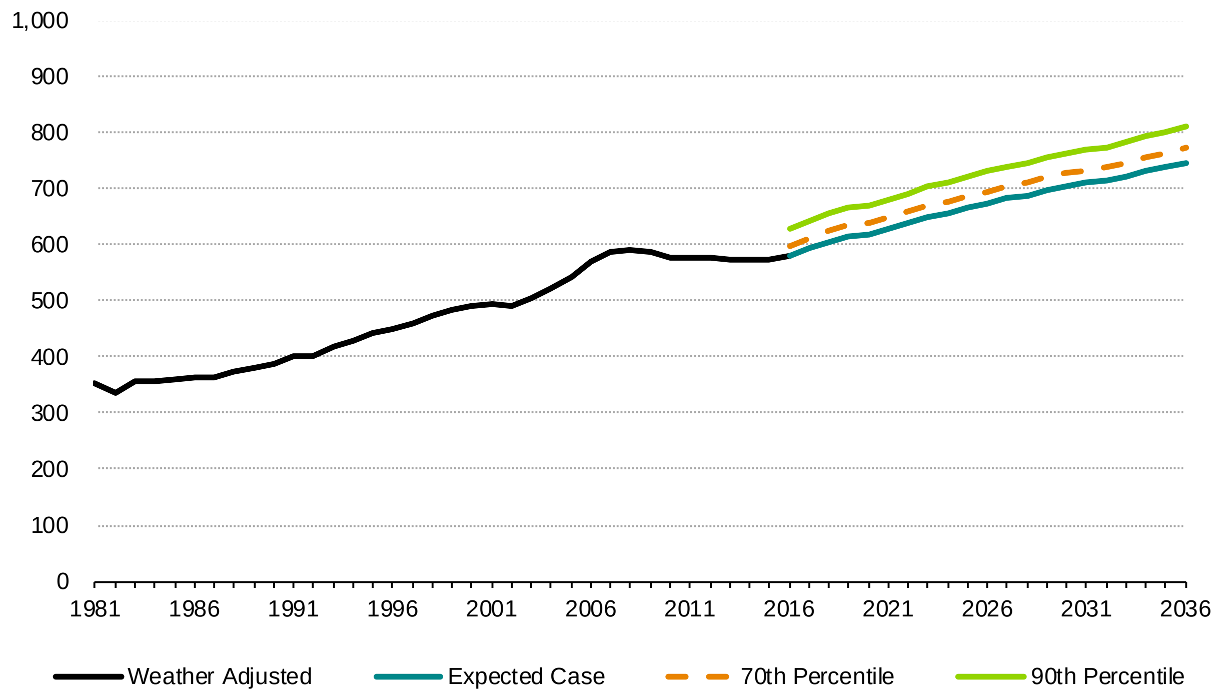

Figure 2. Forecast residential load (aMW)

Sales to residential customers made up 32 percent of Idaho Power's system sales in 1986 and 36 percent of system sales in 2016. The residential customer proportion of system sales is forecast to be approximately 38 percent in 2036. The number of residential customers is projected to increase to approximately 632,000 by December 2036.

The average sales per residential customer increased to over 14,700 kilowatt-hours (kWh) in 1980 before declining to 13,100 kWh in 2001. In 2002 and 2003, residential use per customer dropped dramatically—nearly 500 kWh per customer from 2001—the result of two years of significantly higher electricity prices in those years combined with a weak national and service-area economy. The reduction in electricity prices in June 2003 and a recovery in the service-area economy caused residential use per customer to stabilize through 2007. However, the recession in 2008 and 2009 and conservation efforts further reduced residential use per customer. This trend is expected to continue, as the average sales per residential customer are expected to decline to approximately 10,500 kWh per year in 2036. Average annual sales per residential customer are shown in Figure 3.

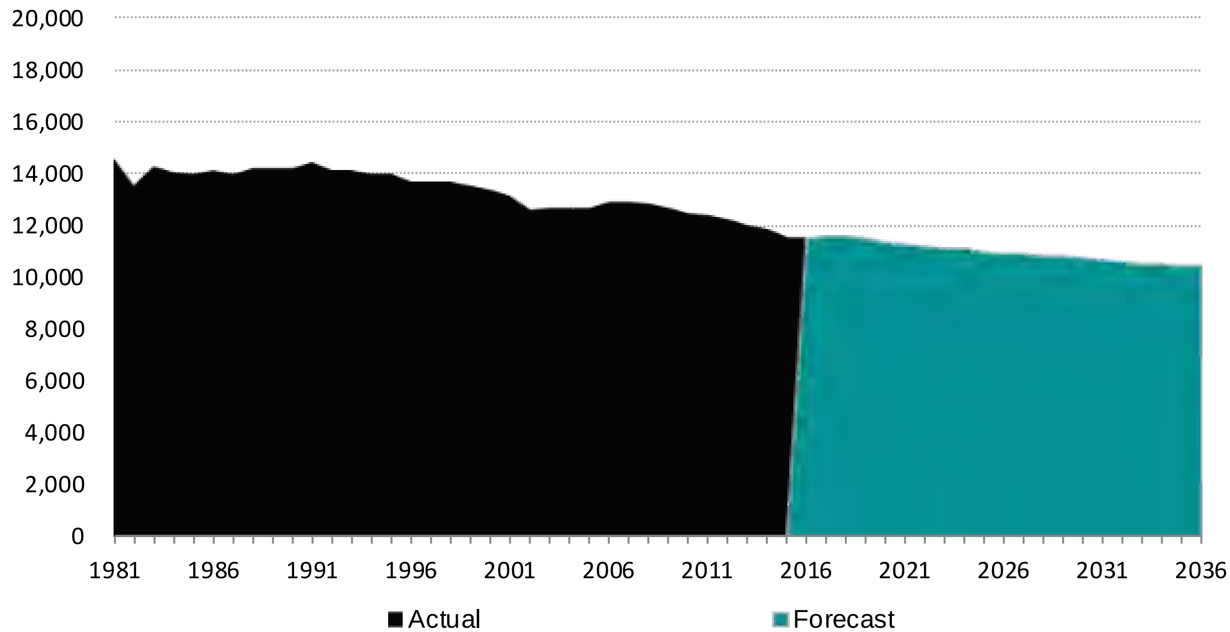

Figure 3. Forecast residential use per customer (weather-adjusted kWh)

Residential customer growth in Idaho Power's service area is a function of the number of new service-area households as derived from Moody's Analytics' May 2016 forecast of county housing stock and demographic data. The residential-customer forecast for 2017 to 2036 shows an average annual growth rate of 1.8 percent.

Sales to residential retail customers is an equation that considers several factors affecting electricity sales to the residential sector. Residential sales are a function of HDD (wintertime); CDD (summertime); the number of service-area households; the real price of electricity; and the real price of natural gas.

Commercial

The commercial category is primarily made up of Idaho Power's small general-service and large general-service customers. Other customers associated with this category include unmetered general service, street-lighting service, traffic-control signal lighting service, and dusk-to-dawn customer lighting.

Within the expected-case scenario, the commercial load is projected to increase from 466 aMW in 2017 to 535 aMW in 2036 (Table 5). The average annual compound-growth rate of the commercial load is 0.7 percent during the forecast period. The commercial load in the 70th-percentile scenario is projected to increase from 471 aMW in 2017 to 543 aMW in 2036. The commercial load forecasts are illustrated in Figure 4.

Table 5. Commercial load growth (aMW)

Growth	2017	2021	2026	2036	Annual Growth Rate 2017–2036
90th Percentile	480	498	517	556	0.8%
70th Percentile	471	489	507	543	0.7%
Expected Case	466	482	500	535	0.7%

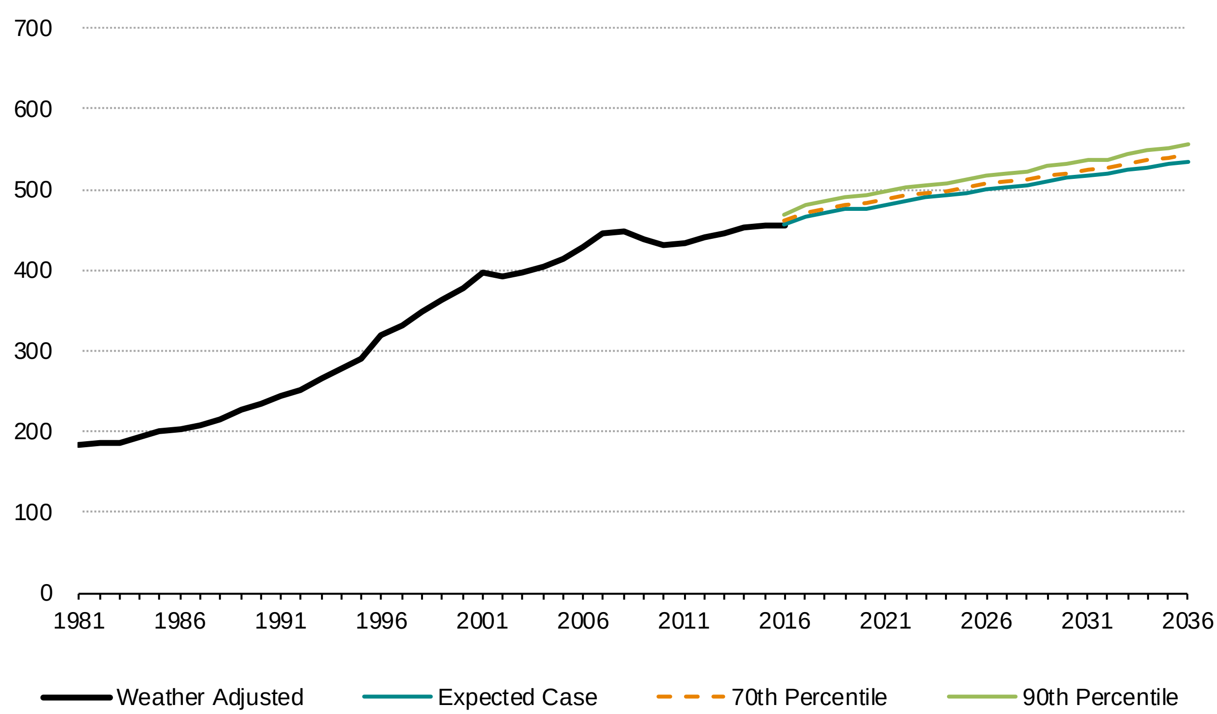

Figure 4. Forecast commercial load (aMW)

With a customer base of nearly 69,000, the commercial class represents the diversity of the service area economy, ranging from residential subdivision pressurized irrigation to manufacturing. Due to this diversity, the category is further segmented into categories associated with common elements of energy-use influences, such as economic variables (e.g., employment), industry (e.g., manufacturing), and building structure characteristics (e.g., offices). Figure 5 shows the breakdown of the categories and their relative sizes based on 2016 billed energy sales.

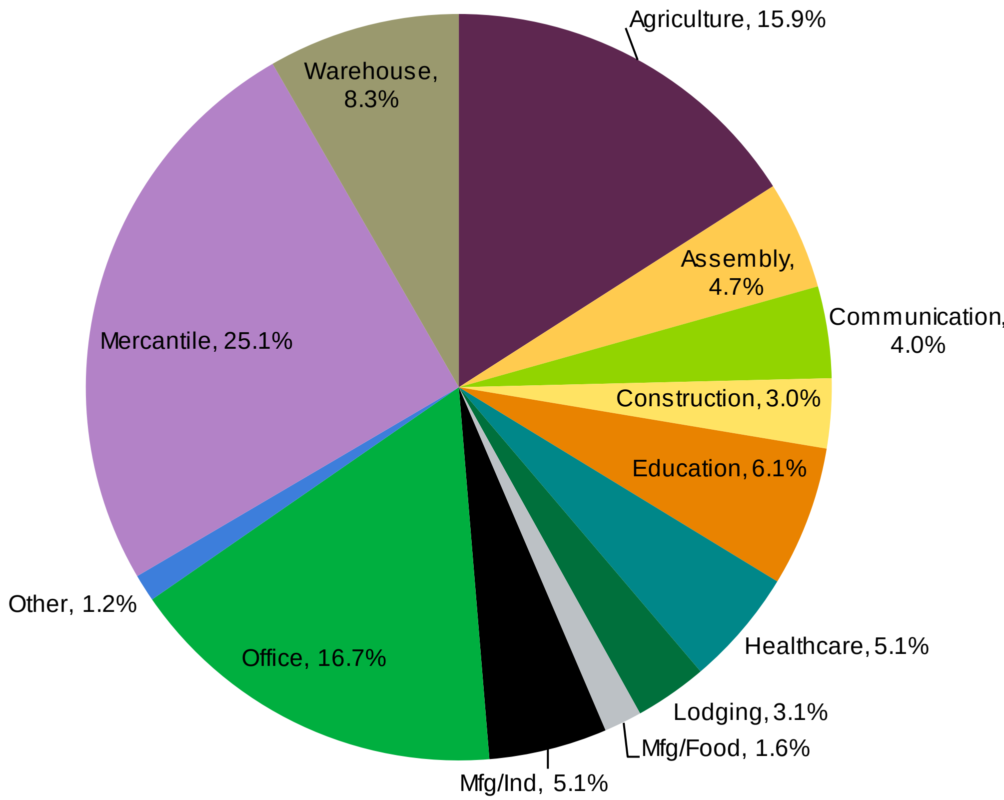

Figure 5. Commercial building share—energy bills

As indicated in Figure 5, the retail goods and service providers of the Mercantile category represent the largest commercial category of energy use, with 25.1% percent of total 2016 use. Total usage in this category has moderated, even considering the growth in total number of customers. This moderation is primarily due to customer consolidation, growth in internet-based sales, and energy efficient retrofit and new-construction technology implementation (particularly in the area of lighting) has grown. Categories showing significant post-recession (2011 to 2016) energy growth include Industrial/Manufacturing (+19.0%), Health Care (+19.2%), and Wholesale Trade (+17.6%).

The number of commercial customers is expected to increase at an average annual rate of 1.8 percent, reaching 97,500 customers by December 2036. The commercial customer forecast for 2017 to 2036 shows an average annual growth rate of 1.8 percent.

In 1986, customers in the commercial category consumed approximately 18 percent of Idaho Power system sales, growing to 28 percent by 2016. This share is forecast to remain at the upper end of this range throughout the planning period.

Figure 6 shows historical and forecast average use per customer (UPC) for the entire category. The commercial-use-per-customer metric in Figure 6 represents an aggregated metric for a highly diverse group of customers with significant differences in total energy use per customer, but it is instructive in aggregate for comparative purposes.

The UPC peaked in 2001 at 67,400 kWh and has declined at approximately 1.00 percent compounded annually to 2016. The UPC is forecast to decrease at an annual rate of 1.0 percent over the planning period. For this category, common elements that drive use down include increases in electricity prices, business-cycle recessions, and the adoption of energy efficiency technology. Within the commercial class UPC varies widely, reflecting the diversity of customer mix and range of operational size.

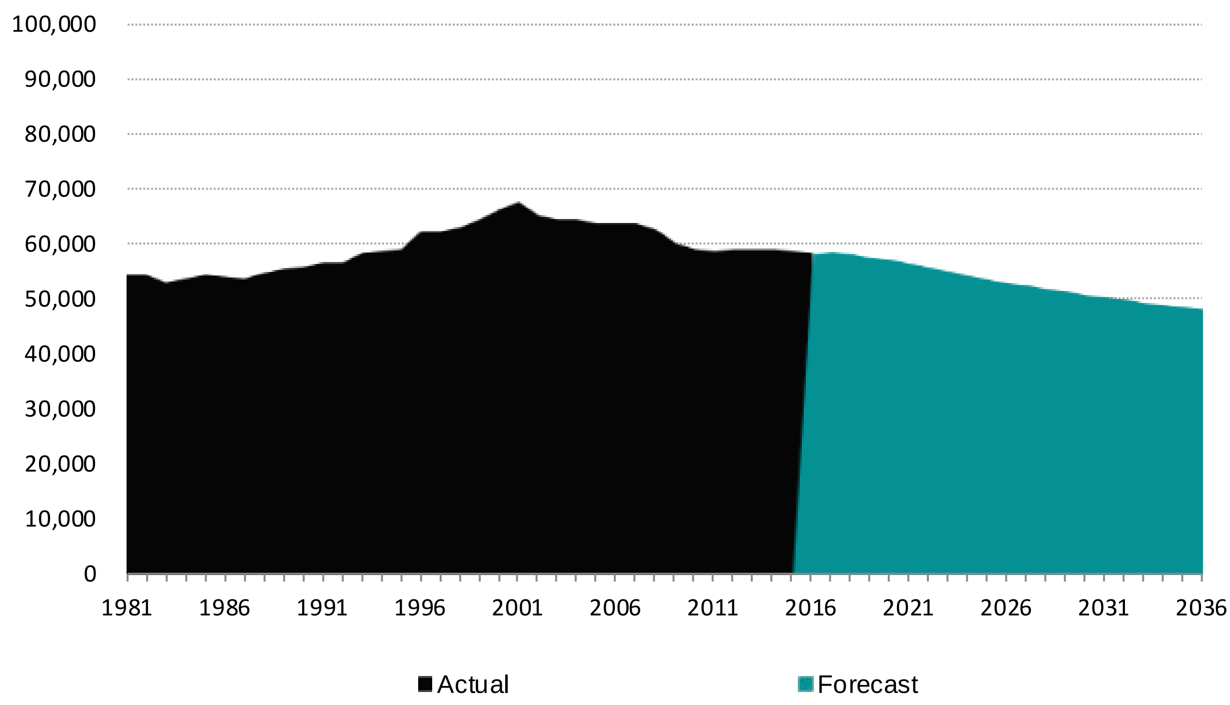

Figure 6. Forecast commercial use per customer (weather-adjusted kWh)

Figure 7 shows the diversity in the commercial segment’s UPC as well as the trend for these sectors. The figure shows the 2016 UPC for each segment relative to the 2011 UPC. A value greater than 1.0 indicates the UPC has risen over the period. The figure supports the general decline of the aggregated trend of Figure 6 but highlights differences in energy and economic dynamics within the heterogeneous commercial category not evident in the residential category.

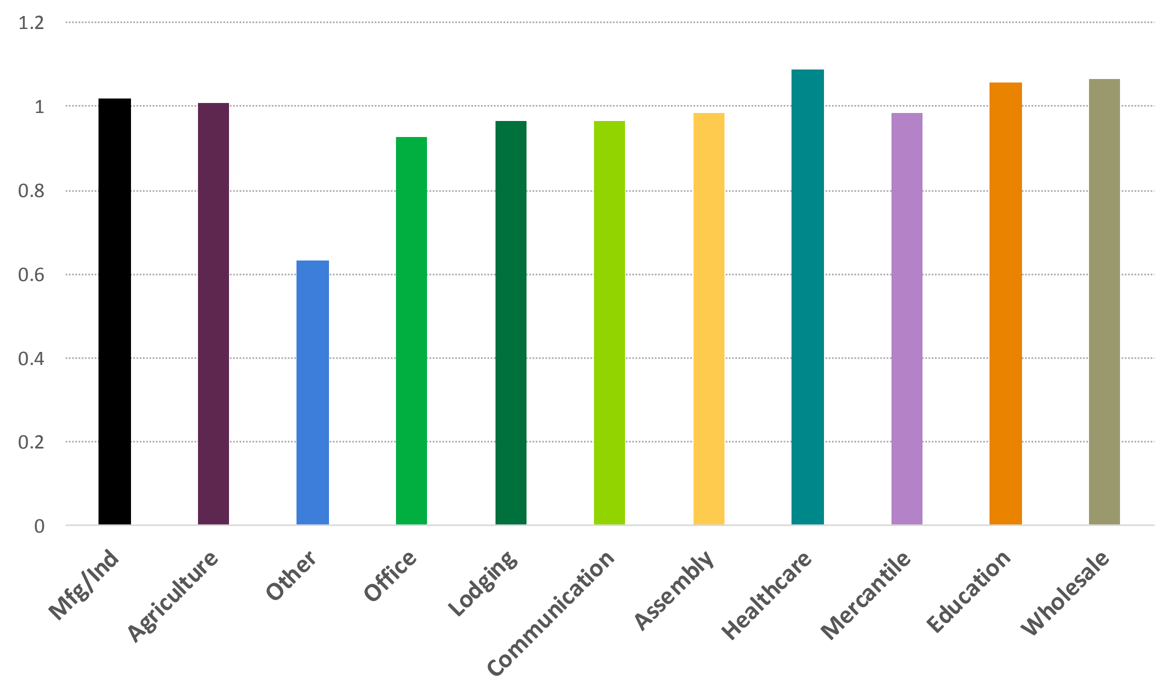

Figure 7. Commercial categories UPC, 2016 relative to 2011

Energy efficiency implementation is a large determinant in UPC decline over time. In the commercial sector, the primary DSM technology impact has come from lighting. The categories of Mercantile and Office are particularly dominant in this implementation as indicated by the UPC trend. Faster growing categories, such as Wholesale and Healthcare tend to show positive UPC trends. Other influences on UPC include differences in price sensitivity, sensitivity to business cycles and weather, and degree and trends in automation. In addition, category UPC can vary when a customer's total use increases to the point where it must, by tariff rules, migrate to an industrial (Rate 19) category. Due to tariff migration, which occurs at the boundary of Schedule 9P (large primary commercial) and Schedule 19 (large industrial), the forecast models aggregate the energy use of these two schedules to ensure continuity in the dependent variable.

The commercial-sales forecast equations consider several varying factors, as informed by the regression models, and vary depending on the sub-category. Typical variables include weather: HDD (wintertime); CDD (summertime); specific industry growth characteristics and outlook; service-area demographics and their derivatives, such as households, employment, and small business conditions; the real price of electricity; and energy efficiency adoption.

IRRIGATION

The irrigation category is comprised of agricultural irrigation service customers. Service under this schedule is applicable to power and energy supplied to agricultural-use customers at one point-of-delivery for operating water pumping or water-delivery systems to irrigate agricultural crops or pasturage.

The expected-case irrigation load is forecast to increase slowly from 221 aMW in 2017 to 246 aMW in 2036, an average annual compound growth rate of 0.6 percent. The expected-case, 70th-percentile, and 90th-percentile scenarios forecast slow growth in irrigation load from 2017 to 2036. In the 70th-percentile scenario, irrigation load is projected to be 235 aMW in 2017 and 260 aMW in 2036. The individual irrigation load forecasts are summarized in Table 6 and illustrated in Figure 8.

Table 6. Irrigation load growth (aMW)

Growth	2017	2021	2026	2036	Annual Growth Rate 2017–2036
90th Percentile	254	259	266	279	0.5%
70th Percentile	235	240	247	260	0.5%
Expected Case	221	226	233	246	0.6%

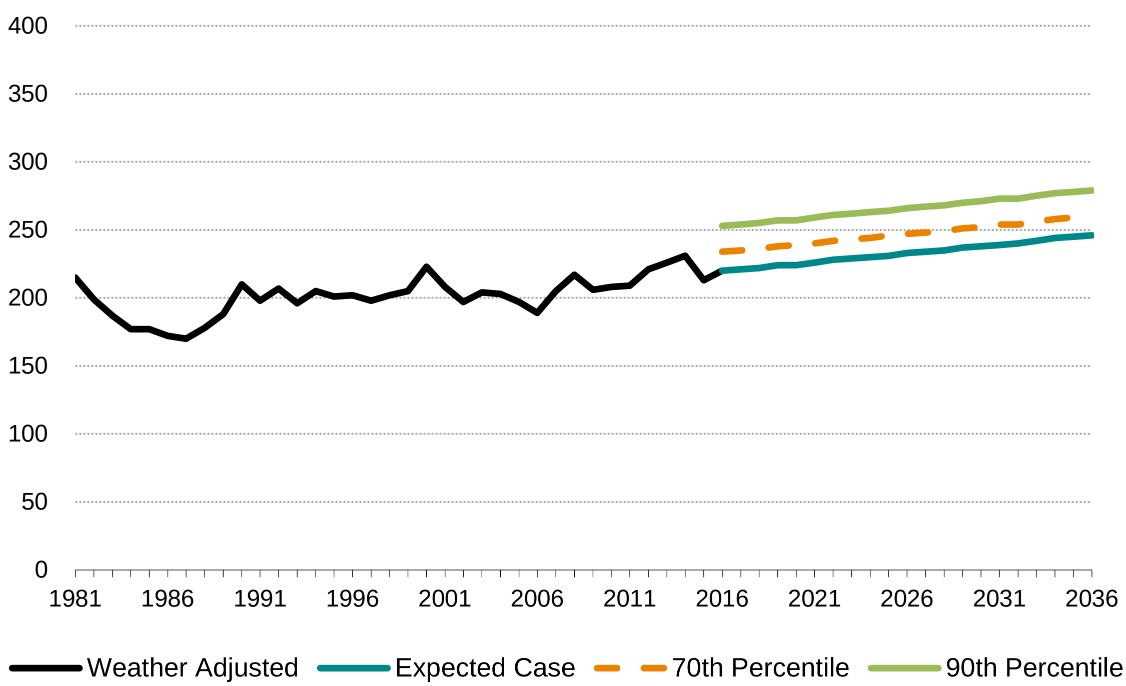

Figure 8. Forecast irrigation load (aMW)

The annual average loads in Table 6 and Figure 8 are calculated using the 8,760 hours in a typical year. In the highly seasonal irrigation sector, over 97 percent of the annual energy is billed during the six months from May through October, and nearly half of the annual energy is billed in just two months, July and August. During the summer, hourly irrigation loads can reach nearly 900 MW. In a normal July, irrigation pumping accounts for roughly 25 percent of the energy consumed during the hour of the annual system peak and nearly 30 percent of the energy consumed during July for general business sales. The 2017 irrigation sales forecast is higher than the 2015 IRP forecast throughout the forecast period due to the trend toward more water-intensive crops, primarily alfalfa and corn, due to growth in the dairy industry. Also, farmers have put high-lift acreage back into production. Additionally, the increased customer count from the conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers trying to reduce labor costs, explains most of the increased energy consumption in recent years.

The 2017 irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature; precipitation; spring rainfall; Palmer Z Index (calculated by the National Ocean and Atmospheric Administration [NOAA] from a combination of precipitation, temperature, and soil moisture data); Moody's Gross Product*: Agriculture, for Idaho*; *Moody's Producer Price Index: Prices Received by Farmers, All Farm Products*; and the real price of electricity. Considerations were made for the unusually low electricity consumption in the 2001 crop year due to a voluntary load-reduction program.

Actual irrigation electricity sales have grown from the 1970 level of 816,000 megawatt-hours (MWh) to a peak amount of 2,097,000 MWh in 2013. In 1977, irrigation sales reached a maximum proportion of 20 percent of Idaho Power system sales. In 2016, the irrigation proportion of system sales was 14 percent due to the much higher relative growth in other customer classes. By 2036, irrigation customers are projected to consume about 12 to 13 percent of Idaho Power system sales.

Regarding customer growth, in 1980, Idaho Power had about 10,850 active irrigation accounts. By 2016, the number of active irrigation accounts had increased to 20,042 and is projected to be nearly 26,000 at the end of the planning period in 2036.

As with other sectors, average use per customer is an important consideration. Since 1988, Idaho Power has experienced growth in the number of irrigation customers but slow growth in total electricity sales (weather-adjusted) to this sector. The number of customers has increased because customers are converting previously furrow-irrigated land to sprinkler-irrigated land. The conversion rate is slow and the kWh use per customer is substantially lower than the average existing Idaho Power irrigation customer. This is because water for sprinkler conversions is drawn from canals and not pumped from deep groundwater wells. In future forecasts, factors related to the conjunctive management of ground and surface water and the possible litigation associated with the resolution will require consideration. Depending on the resolution of these issues, irrigation sales may be impacted.

INDUSTRIAL

The industrial category is comprised of Idaho Power's large power service (Schedule 19) customers requiring monthly metered demands between 1,000 kilowatts (kW) and 20,000 kW. The category name "Industrial" is reflective of load requirements and not necessarily indicative of the industrial nature of the customers' business.

In 1980, Idaho Power had about 112 industrial customers, which represented about 12 percent of Idaho Power's system sales. By December 2016, the number of industrial customers had risen to 118, representing approximately 17 percent of system sales. As mentioned earlier in the commercial discussion, customer counts in this tariff class are impacted by migration from and to the commercial class as dictated by the tariff rules. However, generally speaking, customer count growth is primarily illustrative of the positive economic conditions in the service area. Customers with load greater than Schedule 19 ranges are known as special contract customers and are addressed in the Additional Firm Load section of this document.

In the expected-case forecast, industrial load grows from 281 aMW in 2017 to 320 aMW in 2036, an average annual growth rate of 0.7 percent (Table 7). To a large degree, industrial load variability is not associated with weather conditions as is the case with residential, commercial, and irrigation; therefore, the forecasts in the 70th- and 90th-percentile weather scenarios are identical to the expected-case industrial load scenario. The industrial load forecast is pictured in Figure 9.

Table 7. Industrial load growth (aMW)

Growth	2017	2021	2026	2036	Annual Growth Rate 2017–2036
Expected Case	281	297	305	320	0.7%

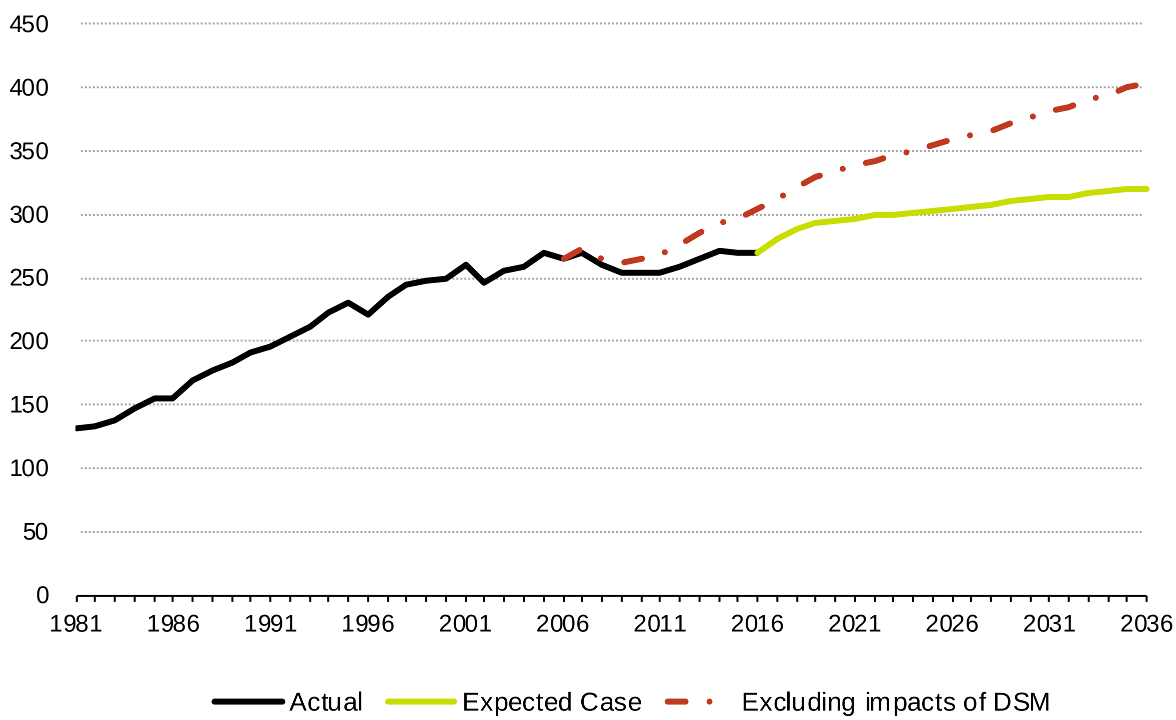

Figure 9. Forecast industrial load (aMW)

As indicated in the figure, the load growth variability is impacted by both economic and other non-weather factors, most particularly the impacts of DSM. The figure highlights the magnitude of DSM on actual and forecast sales. In developing the forecast, customer-specific DSM implementation is isolated, and the actual energy use is adjusted to remove the impacts of DSM to optimize the causal influence of non-DSM causal variables. The history and forecast of DSM is provided by the DSM specialists within Idaho Power. The economic and other independent variables for the regression models are provided by third-party data providers and internally derived time-series for Idaho Power's service area.

Figure 10 illustrates the 2016 share of each of the categories within the Rate 19 customers. By far, the largest share of electricity was consumed by the food manufacturing sector (36%), followed by dairy (18.7%) and electronics/technology (Electech) (7%). The categorization scheme includes a range of industrial building types (assembly, lodging, mercantile, warehouse, office, education, health care). These provide the basis for capturing, modeling, and forecasting the shifting economic landscape that influences industrial category electricity sales.

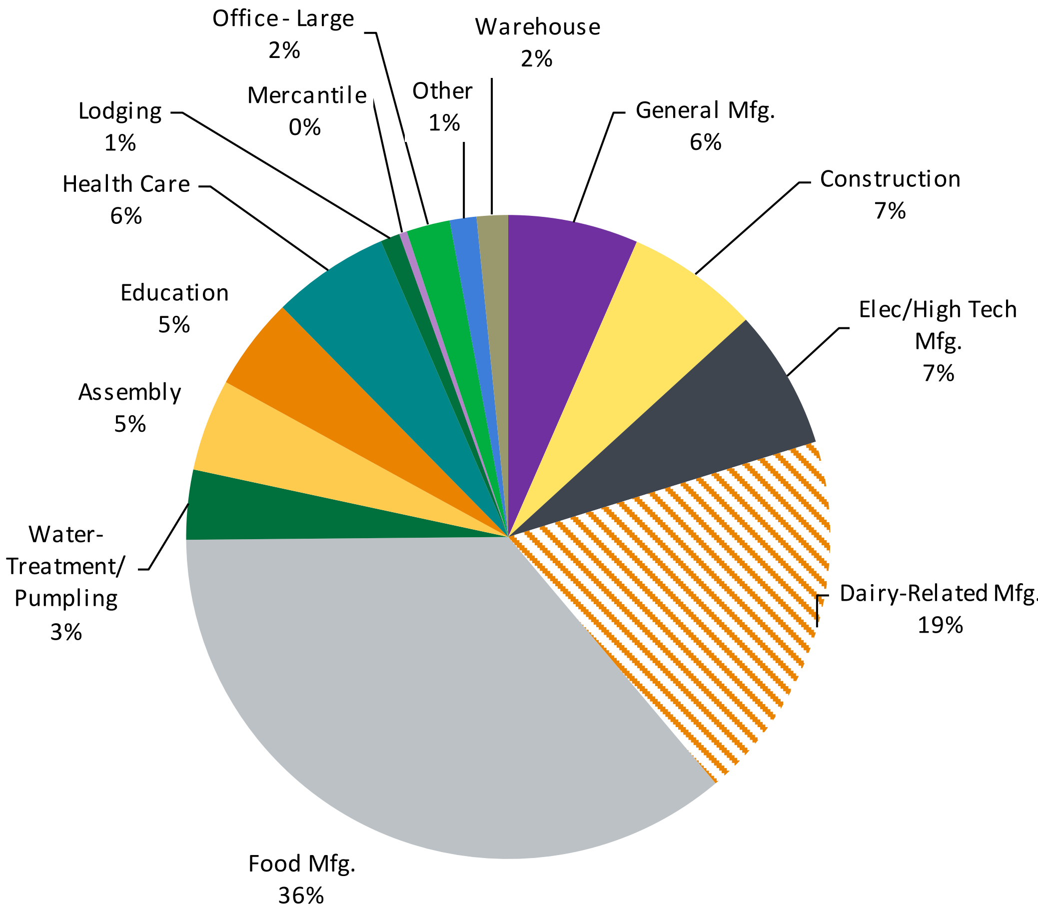

Figure 10. Industrial electricity consumption by industry group (based on 2016 sales)

The regression models and associated explanatory variables resulting from the categorization establish the relationship between historical electricity sales and historical independent economic, price, technological, demographic, and other influences in the form of estimated coefficients from the industry group regression models applied to the appropriate forecasts of independent time series of energy use. From this output, the history and forecast of DSM is subtracted.

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ADDITIONAL FIRM LOAD

The additional firm load category consists of Idaho Power's largest customers. Idaho Power's tariff requires the company serve requests for electric service greater than 20 MW under a special-contract schedule negotiated between Idaho Power and each large-power customer. The contract and tariff schedule are approved by the appropriate regulatory body. A special contract allows customer-specific, cost-of-service analysis and unique operating characteristics to be accounted for in the agreement.

Individual energy and peak-demand forecasts are developed with for special-contract customers, including Micron Technology, Inc.; Simplot Fertilizer Company (Simplot Fertilizer); and the Idaho National Laboratory (INL). These three special-contract customers comprise the forecast category labeled additional firm load.

In the expected-case forecast, additional firm load is expected to increase from 108 aMW in 2017 to 124 aMW in 2036, an average growth rate of 0.7 percent per year over the planning period (Table 8). The additional firm load energy and demand forecasts in the 70th- and 90th-percentile scenarios are identical to the expected-load growth scenario. The scenario of projected additional firm load is illustrated in Figure 11.

Table 8. Additional firm load growth (aMW)

Growth	2017	2021	2026	2036	Annual Growth Rate 2017–2036
Expected Case	108	112	124	124	0.7%

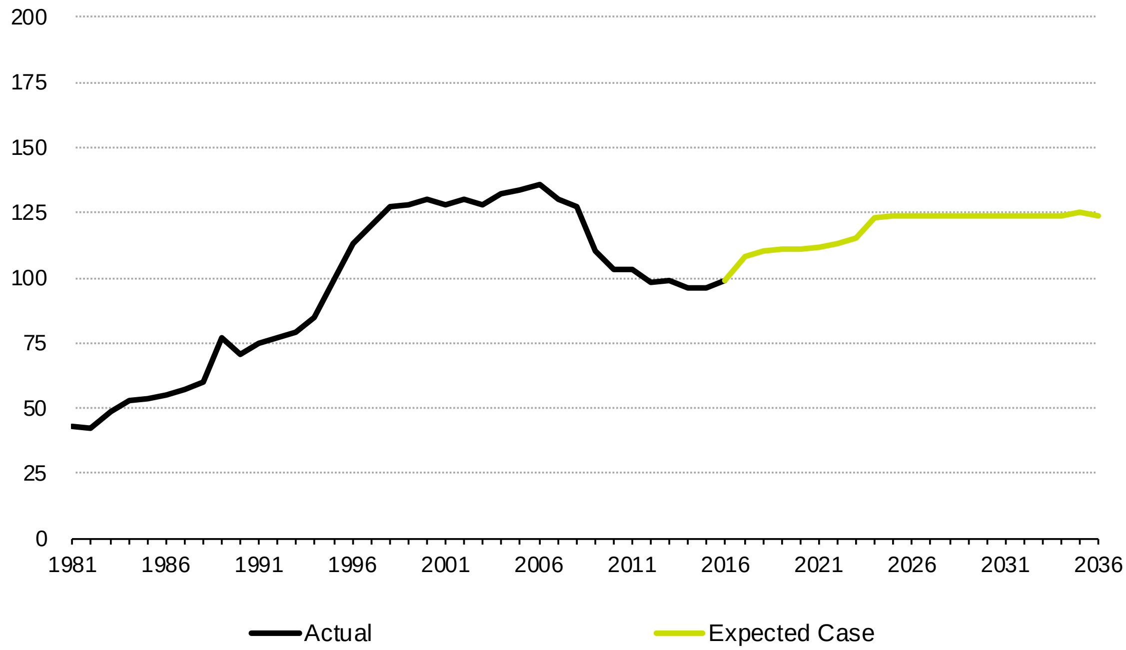

Figure 11. Forecast additional firm load (aMW)

Micron Technology

Micron Technology represents Idaho Power's largest electric load for an individual customer and employs approximately 5,000 workers in the Boise MSA. The company operates its research and development fabrication facility in Boise and performs a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, corporate services, and general services. Micron Technology's electricity use is a function of the market demand for their products.

Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western United States (US). The future electricity usage at the plant is expected to grow slowly through 2016, then stay flat throughout the remainder of the planning period.

Idaho National Laboratory

INL is part of the US Department of Energy's (DOE) complex of national laboratories. INL is the nation's leading center for nuclear energy research and development. The DOE provided an energy-consumption and peak-demand forecast through 2036 for the INL. The forecast calls for loads to increase through 2024 and levelize throughout the forecast period.

ENERGY EFFICIENCY AND DEMAND RESPONSE

Energy efficiency and demand response impacts are treated differently in the forecasting and planning process. Energy efficiency impacts (reductions in energy use) are explicitly integrated into the forecast models. Demand response impacts are explicitly *excluded* from the forecast models; the impacts of demand response are modeled in the load and resource balance as a supply-side resource for reducing peak-demand periods.

Energy Efficiency

Energy efficiency (EE) influences on past and future load consist of utility programs, statutory codes, and manufacturing standards for appliances, equipment, and building materials that reduce energy consumption. As the influence of statutory codes and manufacturing standards on residential and commercial customers has increased in importance relative to utility programs, Idaho Power forecast models have been modified to ensure they capture these influences. For residential models, the physical unit flow of energy-efficient products is captured through shipment data to resellers and installers. The source for this data is the DOE (the data also serves as input to the DOE National Energy Model [NEM]), and the data is refined by Itron for utility-specific applications. This data captures energy-efficient installations regardless of the source (e.g., programs, standards, and codes). However, Idaho Power closely monitors the assumptions and impacts of DOE data to ensure the model correctly captures all energy efficiency impacts.

Energy Efficiency data for irrigation customers and some commercial and industrial customers is not directly surveyed and collected by the DOE; therefore, models for efficiency impacts have been developed derived from methodologies established in Itron's white paper, *Incorporating DSM into the Load Forecast*.[2] These approaches include; isolating historical efficiency data and removing the impacts from historical sales (as previously discussed in application to the industrial customers); applying historical and forecast EE as an independent variable in the regression model (this method was utilized for the commercial customers); and marginal comparison of DSM growth rates for historical versus forecast trend. If there is a significant change in future trends (i.e., trends unseen by the regression model of historical energy and conservation trends), the forecast output is adjusted to realize the trend change embedded in the regression output. These alternate models utilize energy efficiency data provided by Idaho Power's internal DSM group. The DSM group develops an independent energy efficiency/DSM forecast in collaboration with AEG consultants. This data served as direct input into the commercial, industrial, and irrigation models. The forecast developed by Idaho Power coincides

[2] Stuart McMenamin and Mark Quan. *Incorporating DSM into the Load Forecast*. Itron, https://www.itron.com/na/PublishedContent/Incorporating%20DSM%20into%20the%20Load%20Forecast.pdf (accessed February 3, 2011).

with models that AEG developed. Output for all category forecasts are compared to the AEG output as well as data from DOE Form 861 of utility-reported data. Data from regional utility acquisition is compared to Idaho Power data to ensure the regional assumptions are consistent with Idaho Power assumptions in capturing all energy savings.

Energy savings from utility energy efficiency programs are typically measured and reported at the point of delivery (customer’s meter). Therefore, energy efficiency savings are increased by the amount of energy lost in transmitting the electricity from the generation source to the customer’s meter.

Demand Response

Beginning with the 2009 IRP, the reduction in load associated with demand response programs has been effectively treated as a supply-side resource and accounted for in the load and resource balance. Demand response program data, including operational targets for demand reduction, program expenses, and cost-effective summaries are detailed in *Appendix C—Technical Appendix*.

As supply-side resources, demand response program impacts are not incorporated into the sales and load forecast. In the load and resource balance, the forecast of existing demand response programs is subtracted from the peak-hour load forecast prior to accounting for existing supply-side resources. Likewise, the performance of new demand response programs is accounted for prior to determining the need for additional supply-side resources. However, because energy efficiency programs have an impact on peak demand reduction, a component of peak-hour load reduction is integrated into the sales and load forecast models. This provides a consistent treatment of both types of programs, as energy efficiency programs are considered in the sales and load forecast, while all demand response programs are included in the load and resource balance.

A thorough description of each of the energy efficiency and demand response programs is included in *Appendix B—Demand Side Management 2016 Annual Report*.

Company System Peak

System peak load includes the sum of the coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as special contracts (including Astaris, historically) and on-system contracts (Raft River and the City of Weiser, historically).

The all-time system summer peak demand was 3,407 MW, recorded on Tuesday, July 2, 2013, at 4:00 p.m. That record was approached when the peak demand reached 3,402 MW on Tuesday, June 30, 2015, at 4:00 p.m. The system summer peak load growth accelerated from 1998 to 2008 as a record number of residential, commercial, and industrial customers were added to the system and air conditioning (A/C) became standard in nearly all new residential homes and new commercial buildings.

Idaho Power has two peak periods: 1) a winter peak, resulting primarily from space-heating demand that normally occurs in December, January, or February and 2) a larger summer peak that normally occurs in late June or July, which coincides with cooling load and irrigation pumping demand.

For resource planning purposes in the 95th-percentile forecast, the system summer peak load is expected to increase from 3,586 MW in 2017 to 4,641 MW in 2036. In the 90th-percentile forecast, the system summer peak load is expected to increase from 3,566 MW in 2017 to 4,613 MW in 2036, an average growth rate of 1.4 percent per year over the planning period (Table 9).

Table 9. System summer peak load growth (MW)

Growth	2017	2021	2026	2036	Annual Growth Rate 2017–2036
95th Percentile	3,586	3,819	4,102	4,641	1.4%
90th Percentile	3,566	3,797	4,078	4,613	1.4%
50th Percentile	3,446	3,668	3,937	4,449	1.4%

The three scenarios of projected system summer peak loads are illustrated in Figure 12. Much of the variation in peak load is due to weather conditions. Although not entirely, unique economic events as occurred in the summer of 2001, when the summer peak was dampened by the nearly 30-percent curtailment in irrigation load due to the 2001 voluntary load-reduction program.

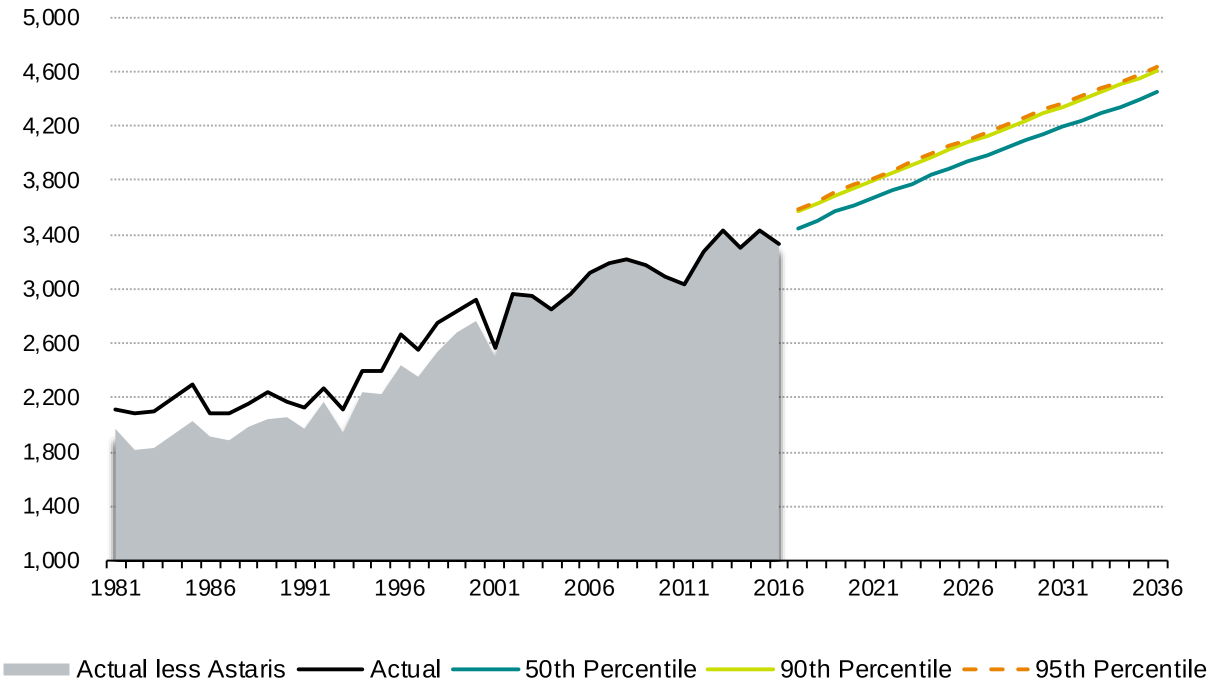

Figure 12. Forecast system summer peak (MW)

As of December 31, 2016, the all-time system winter peak demand was 2,527 MW, reached on Thursday, December 10, 2009, at 8:00 a.m. and January 06, 2017, at 9:00am. As shown in Figure 13, the historical system winter peak load is much more variable than the summer system peak load. This is because the variability of peak-day temperatures in winter months is more significant than the variability of peak-day temperatures in summer months. The wider spread of the winter peak forecast lines in Figure 13 illustrates the higher variability associated with winter peak-day temperatures.

For resource planning purposes, 95th-percentile forecast, the system winter peak load is expected to increase from 2,611 MW in 2017 to 2,896 MW in 2036, an average growth rate of 0.5 percent per year over the planning period (Table 10). In the 90th-percentile forecast, the system winter peak load is expected to increase from 2,517 MW in 2017 to 2,846 MW in 2036, an average growth rate of 0.9 percent per year over the planning period (Table 10). The three scenarios of projected system winter peak load are illustrated in Figure 13.[3]

[3] Idaho Power uses a median peak-day temperature driver in lieu of an average peak-day temperature driver in the 50/50 peak-demand forecast scenario. The median peak-day temperature has a 50-percent probability of being exceeded. Peak-day temperatures are not normally distributed and can be skewed by one or more extreme observations; therefore, the median temperature better reflects expected temperatures within the context of probabilistic percentiles. The weighted average peak-day temperature drivers are calculated over the 1986 to 2015 time period (the most recent 30 years).

Table 10. System winter peak load growth (MW)

Growth	2017	2021	2026	2036	Annual Growth Rate 2017–2036
95th Percentile	2,611	2,691	2,769	2,896	0.5%
90th Percentile	2,517	2,596	2,675	2,846	0.7%
50th Percentile	2,294	2,415	2,534	2,732	0.9%

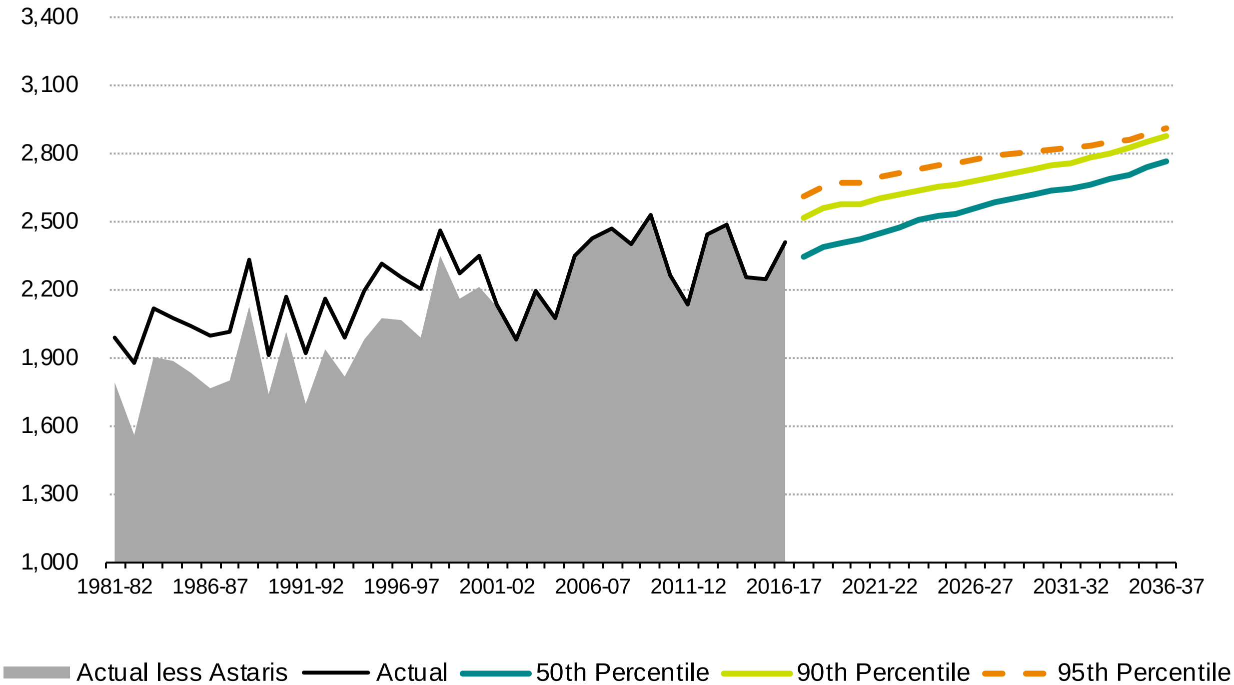

Figure 13. Forecast system winter peak (MW)

Additionally, note the 2017 IRP peak-demand forecast model explicitly excludes the impact of demand response programs to establish peak impacts. The exclusion allows for planning for demand response programs and supply-side resources in meeting peak demand. Demand response program impacts are accounted for in the IRP load and resource balance and are reflected as a reduction in peak demand.

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Company System Load

System load is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts (including past sales to Astaris) and on-system contracts (including past sales to Raft River and the City of Weiser). The system load excludes all long-term, firm, off-system contracts.

The expected-case system load forecast is based on the output of the regression and forecasting models referenced previously and represents Idaho Power's most probable load growth during the planning period. The expected-case forecast system load growth rate averages 0.9 percent per year from 2017 to 2036. Company system load projections are reported in Table 11 and shown in Figure 14.

In the expected-case forecast, the company system load is expected to increase from 1,810 aMW in 2017 to 2,142 aMW in 2036. In the 70th-percentile forecast, the company system load is expected to increase from 1,853 aMW in 2017 to 2,193 aMW by 2036, an average growth rate of 0.9 percent per year over the planning period (Table 11).

Table 11. System load growth (aMW)

Growth	2017	2021	2026	2036	Annual Growth Rate 2017–2036
90th Percentile	1,917	2,006	2,108	2,269	0.9%
70th Percentile	1,853	1,939	2,037	2,193	0.9%
Expected Case	1,810	1,894	1,990	2,142	0.9%

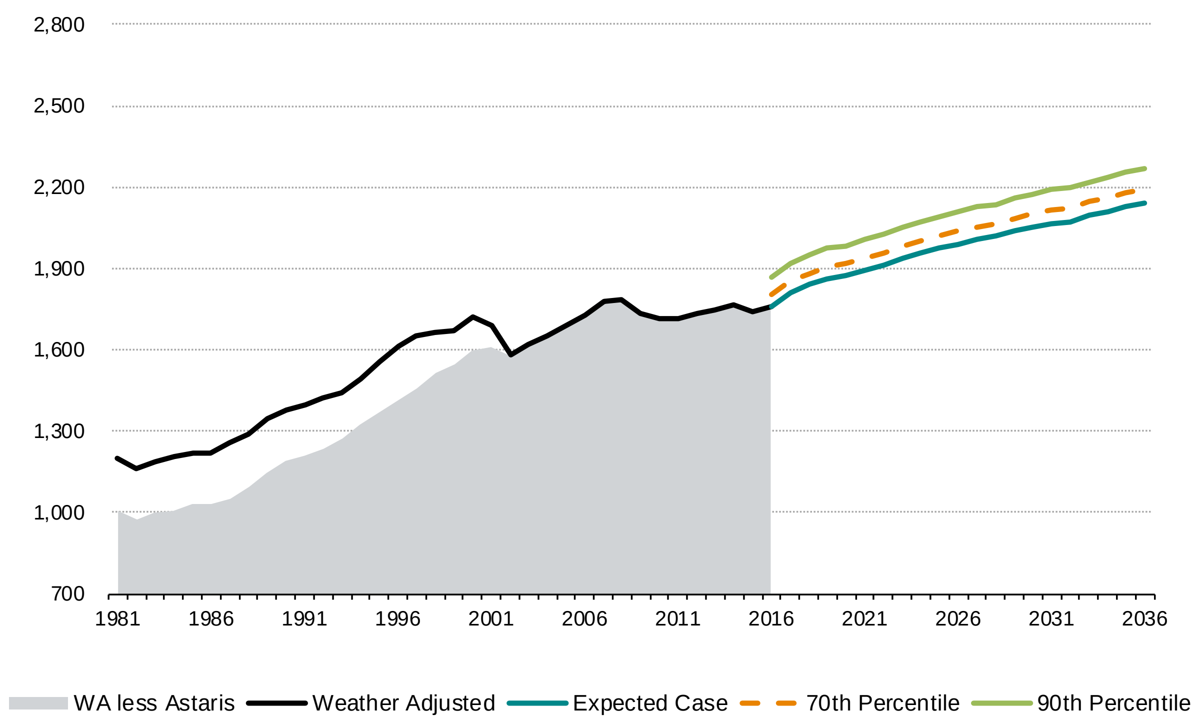

Figure 14. Forecast system load (aMW)

The system load, excluding Astaris[4], portrays the current underlying general business growth trend within the service area. However, the system load with Astaris is instructive in regard to the impact of a new large-load customer on system load. As noted previously, the forecast excludes any such prospective large-load customers.

Accompanied by an outlook of moderate economic growth for Idaho Power's service area throughout the forecast period, continued growth in Idaho Power's system load is projected. Total load is made up of system load plus long-term, firm, off-system contracts. At this time, there are no contracts in effect to provide long-term, firm energy off-system.

The composition of system company electricity sales by year is shown in Figure 15. Residential sales are forecast to be nearly 26 percent higher in 2036, gaining 1.4 million MWh over 2017. Commercial sales are also expected to be 15 percent higher, or 0.6 million MWh, than in 2017, followed by industrial (15 percent higher, or 0.4 million additional MWh) and irrigation (12 percent higher in 2036 than 2017).

[4] The Astaris elemental phosphorous plant (previously FMC) was located at the western edge of Pocatello, Idaho. Although no longer a customer of Idaho Power, Astaris had been Idaho Power's largest individual customer and, in some years, averaged nearly 200 aMW each month. In April 2002, the special contract between Astaris and Idaho Power was terminated.

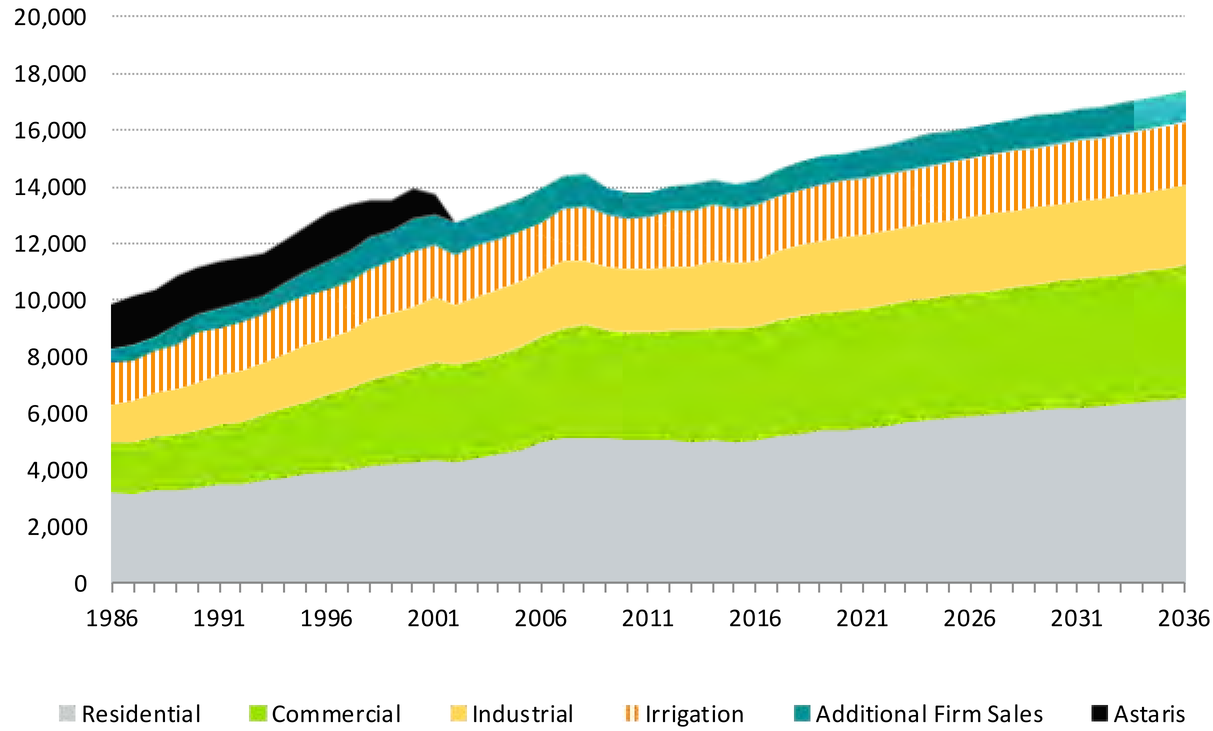

Figure 15. Composition of system company electricity sales (thousands of MWh)

Fuel Prices

Fuel prices, in combination with service-area demographic and economic drivers, impact long-term trends in electricity sales. Changes in relative fuel prices can also impact the future demand for electricity. Class-level and economic-sector-level regression models were used to identify the relationships between real historical electricity prices and their impact on historical electricity sales. The estimated coefficients from these models were used as drivers in the individual sales forecast models.

Short-term and long-term nominal electricity price increases are generated internally from Idaho Power financial models. The US Energy Information Administration (EIA) provides the forecasts of long-term changes in nominal natural gas prices. The nominal price estimates are adjusted for projected inflation by applying the appropriate economic deflators to arrive at real fuel prices. The projected average annual growth rates of fuel prices in nominal and real terms (adjusted for inflation) are presented in Table 12. The growth rates shown are for residential fuel prices and can be used as a proxy for fuel-price growth rates in the commercial, industrial, and irrigation sectors.

Table 12. Residential fuel-price escalation (2017–2036) (average annual percent change)

	Nominal	Real*
Electricity—2017 IRP	1.2%	-0.7%
Electricity—2015 IRP	2.0%	0.0%
Natural Gas	3.7%	1.7%

* Adjusted for inflation

Figure 16 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1980 to 2016 and over the forecast period 2017 to 2036. Both nominal and real prices are shown. In the 2017 IRP, nominal electricity prices are expected to climb to about 13 cents per kWh by the end of the forecast period in 2036. Real electricity prices (inflation adjusted) are expected to decline over the forecast period at an average rate of 0.7 percent annually. In the 2015 IRP, nominal electricity prices were assumed to climb to about 15 cents per kWh by 2036, and real electricity prices (inflation adjusted) were expected to remain flat over the forecast period at an average rate of 0.0 percent annually.

The electricity price forecast used to prepare the sales and load forecast in the 2017 IRP reflected the additional plant investment and variable costs of integrating the resources identified in the 2015 IRP preferred portfolio. When compared to the electricity price forecast used to prepare the 2015 IRP sales and load forecast, the 2017 IRP price forecast yielded lower future prices. The retail prices are more evidently lower in the second 10 years of the planning period and impact the sales forecast positively, a consequence of the inverse relationship between electricity prices and electricity demand.

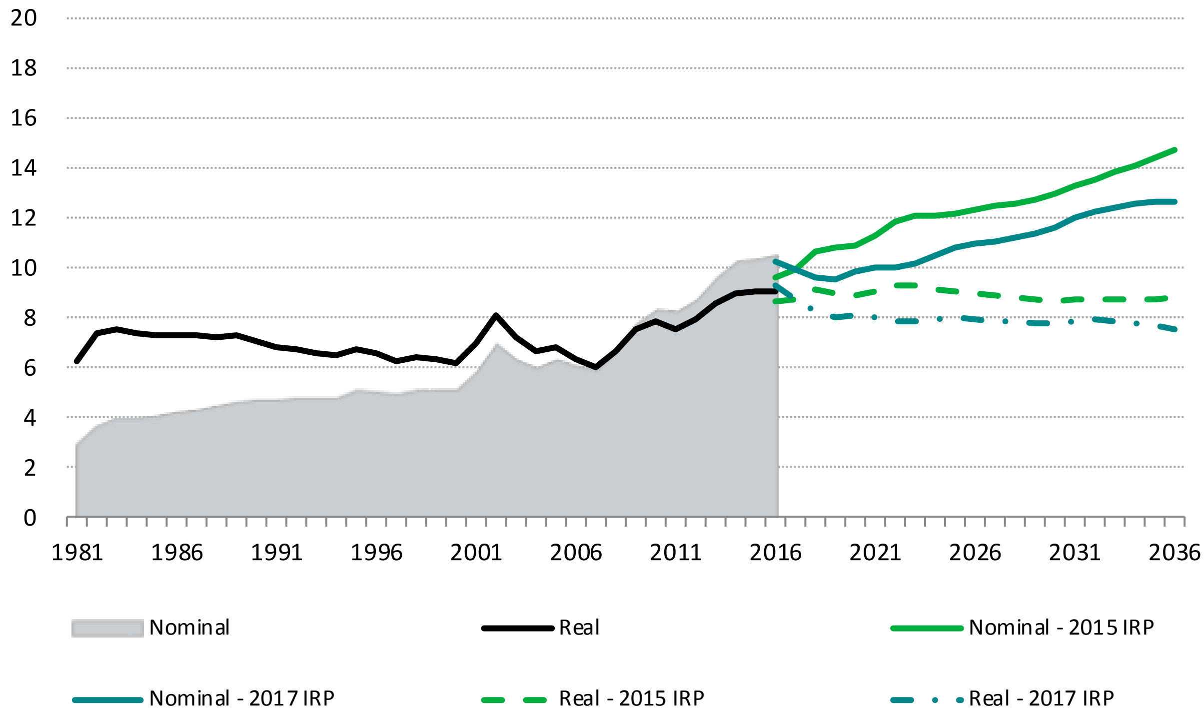

Figure 16. Forecast residential electricity prices (cents per kWh)

Electricity prices for Idaho Power customers increased significantly in 2001 and 2002 because of the power cost adjustment (PCA) impact on rates, a direct result of the western US energy crisis of 2000 and 2001. Prior to 2001, Idaho Power's electricity prices were historically quite stable. From 1990 to 2000, nominal electricity prices rose only 8 percent overall, an annual average compound growth rate of 0.8 percent annually. More recently, over the period 2006 to 2016, nominal electricity prices rose 72 percent overall, an annual average compound growth rate of 5.6 percent annually.

Figure 17 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1981 to 2015 and forecast prices from 2016 to 2036. Natural gas prices remained stable and flat throughout the 1990s before moving sharply higher in 2001. Since spiking in 2001, natural gas prices moved downward for a couple of years before moving sharply upward in 2004 through 2006. Since 2006, natural gas prices have declined about 30 percent, compared to 2015. Nominal natural gas prices are initially expected to drop by 8 percent in 2016, then rise at a steady pace throughout the remainder of the forecast period until more than doubling by 2036, growing at an average rate of 3.7 percent per year. Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 1.7 percent annually.

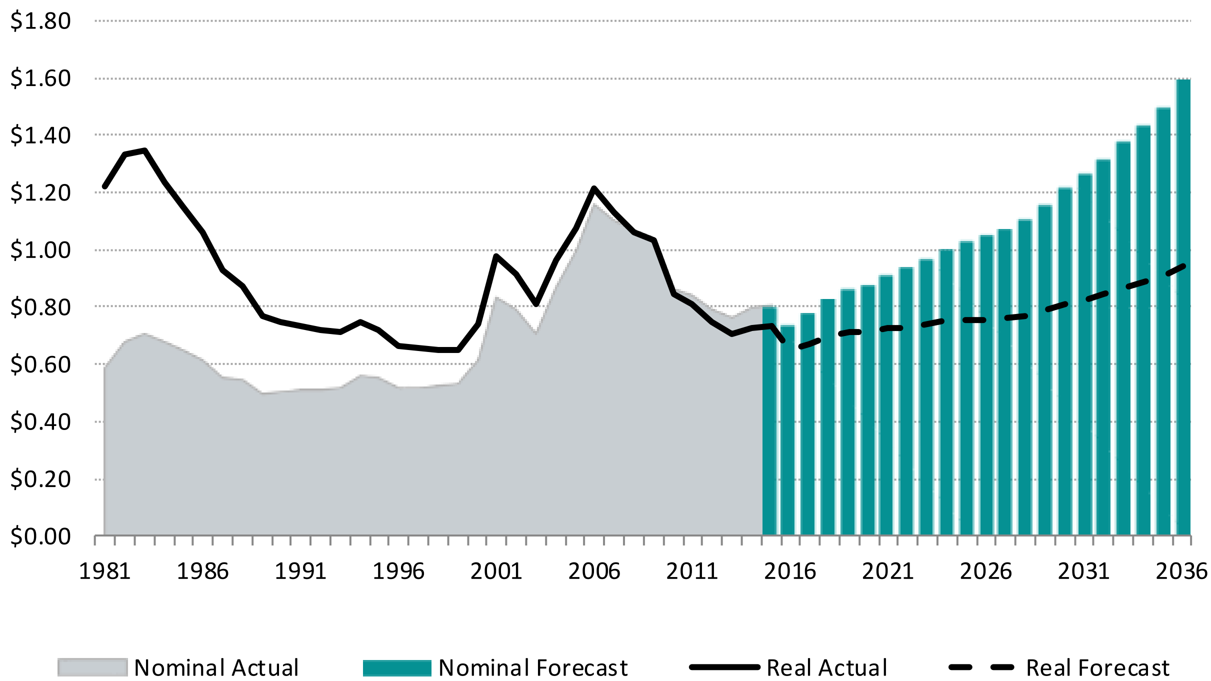

Figure 17. Forecast residential natural gas prices (dollars per therm)

If future natural gas price increases outpace electricity price increases, the operating costs of space heating and water heating with electricity would become more advantageous when compared to that of natural gas. However, in the 2017 IRP price forecast, the long-term growth rates of electricity and natural gas prices are nearly identical.

Electric Vehicles

The load forecast includes an update of the impact of plug-in electric vehicles (PEV) on system load to reflect the future impact of this relatively new and evolving source of energy use. While PEV consumer adoption rates in Idaho Power's service area remain relatively low, with continued technological advancement, limiting attributes of vehicle range and re-fueling time continue to improve the competitiveness of these vehicles to non-electric models.

Since the first introduction of the Chevy Volt and Nissan Leaf, the number of PEVs offered in the marketplace has proliferated to over 50 models since 2007. Early in this period, PEVs were sold with unique model names (e.g., VOLT); however, as the market grows, the plug-in technology is increasingly offered as an option to existing models (e.g., Ford Focus).

Initially, the Idaho Power forecast for PEV impact relied on third-party forecasts from the Electric Power Research Institute (EPRI) and Oak Ridge National Laboratory due to a lack of service-area vehicle registration data; however, beginning with the 2011 IRP,

sufficient service-area data became available via vehicle registration data provided by the Idaho Transportation Department (ITD). This data provides a basis from which to develop service-area adoption rates and support the collection of charging behavior. The methodology continues to integrate the fuel and technology share forecasts of the DOE's NEM.
The Idaho Power vehicle share forecast uses these models as well as a Bass consumer adoption model as informed by registration data. Load impacts from the share model output are derived from assumptions of battery-only and hybrid plug-in shares evident from Idaho Power observations and informed by the DOE.

Currently, the registration data collection methodology is being revised to capture vehicles sold with PEV technology as an option (e.g., Ford Focus). The methodology will require the unique string of characters within the vehicle identification number (VIN) to be identified and serve as a key value in the ITD data extraction.

The PEV forecast in the IRP did include registration data for the Toyota Prius PEV but did not capture all models for which PEV technology is sold as an option; however, to capture the impact of these models on future adoption, the forecast used the forecast national share assumptions from the DOE. The net effect was to rely less on the registration data than the 2015 IRP model and more on third-party assumptions, as was the case in earlier forecasts.

Net Metering

In recent years, the number of customers signing up for net-metering service (Schedule 84) has raised dramatically, especially for residential customers. Currently, there are approximately 900 residential and 100 commercial net-metering customers. While the recent adoption of solar is relatively strong for our service area, the current population of net-metering customers comprises around one-fifth of 1 percent of the population of retail customers.

The installation of generating and storage equipment at customer sites will cause the demand for electricity delivered by Idaho Power to be reshaped throughout the year. It is important to measure the overall and future impact on the sales forecast. Therefore, this year's long term sales forecast was adjusted downward to reflect the impact of the increase in the number of net-metering customers, specifically solar, connecting to our system.

Schedule 84 (net-metering) customer billing histories were compared to billing histories prior to said customer becoming a net-metering customer. The resulting average monthly impact-per-customer (in kWh) was then multiplied by a forecast of the Schedule 84 residential and commercial customer count to estimate the future energy impact on the sales forecast.
The forecast of net metering customers serves as a function of historical trends and current policy considerations.

The resulting forecast of net-metering customers multiplied by the estimated use-per-customer sales impact per customer resulted in a monthly downward adjustment to the sales forecast for each class. At the end of the forecast period, 2036, the annual residential sales reduction was about 18 aMW, and the commercial reduction was less than 1 aMW.

OTHER CONSIDERATIONS

Since the residential, commercial, irrigation, and industrial sales forecasts provide a forecast of sales as billed, it is necessary to adjust these billed sales to the proper time frame to reflect the required generation needed in each calendar month. To determine calendar-month sales from billed sales, the billed sales must first be converted from billed periods to calendar months to synchronize them with the time period in which load is generated. The calendar-month sales are then converted to calendar-month average load by adding losses and dividing by the number of hours in each month.

Loss factors are determined by Idaho Power's Transmission Planning department. The annual average energy loss coefficients are multiplied by the calendar-month load, yielding the system load, including losses. A system loss study of 2012 was completed in May 2014. The results of the study concluded that on average, the revised loss coefficients were lower than those applied to generation forecasts developed prior to the 2015 IRP and were used in the development of the 2017 IRP sales and load forecast. This resulted in a one-time permanent reduction of nearly 20 aMW to the load forecast annually.

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CONTRACT OFF-SYSTEM LOAD

The contract off-system category represents long-term contracts to supply firm energy to off-system customers. Long-term contracts are contracts effective during the forecast period lasting for more than one year. At this time, there are no long-term contracts.

The historical consumption for the contract off-system load category was considerable in the early 1990s; however, after 1995, off-system loads declined through 2005. As intended, the off-system contracts and their corresponding energy requirements expired as Idaho Power's surplus energy diminished due to retail load growth. In the future, Idaho Power may enter additional long-term contracts to supply firm energy to off-system customers if surplus energy is available.

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Appendix A1. Historical and Projected Sales and Load

Residential Load

Historical Residential Sales and Load, 1976–2016 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1976	175,720	–	13,280	2,334	–	267
1977	184,561	5.0%	13,240	2,444	4.7%	284
1978	194,650	5.5%	14,559	2,834	16.0%	320
1979	202,982	4.3%	13,904	2,822	-0.4%	329
1980	209,629	3.3%	14,657	3,073	8.9%	350
1981	213,579	1.9%	14,583	3,115	1.4%	353
1982	216,696	1.5%	13,544	2,935	-5.8%	337
1983	219,849	1.5%	14,287	3,141	7.0%	358
1984	222,695	1.3%	14,078	3,135	-0.2%	357
1985	225,185	1.1%	13,988	3,150	0.5%	360
1986	227,081	0.8%	14,095	3,201	1.6%	365
1987	228,868	0.8%	13,960	3,195	-0.2%	365
1988	230,771	0.8%	14,237	3,285	2.8%	375
1989	233,370	1.1%	14,237	3,323	1.1%	380
1990	238,117	2.0%	14,223	3,387	1.9%	388
1991	243,207	2.1%	14,428	3,509	3.6%	401
1992	249,767	2.7%	14,099	3,521	0.4%	402
1993	258,271	3.4%	14,124	3,648	3.6%	417
1994	267,854	3.7%	13,991	3,748	2.7%	429
1995	277,131	3.5%	13,950	3,866	3.2%	442
1996	286,227	3.3%	13,713	3,925	1.5%	448
1997	294,674	3.0%	13,640	4,019	2.4%	459
1998	303,300	2.9%	13,681	4,150	3.2%	474
1999	312,901	3.2%	13,548	4,239	2.2%	484
2000	322,402	3.0%	13,365	4,309	1.6%	492
2001	331,009	2.7%	13,128	4,346	0.9%	495
2002	339,764	2.6%	12,641	4,295	-1.2%	491
2003	349,219	2.8%	12,673	4,426	3.0%	506
2004	360,462	3.2%	12,675	4,569	3.2%	522
2005	373,602	3.6%	12,668	4,733	3.6%	543
2006	387,707	3.8%	12,884	4,995	5.5%	571
2007	397,286	2.5%	12,922	5,134	2.8%	587
2008	402,520	1.3%	12,838	5,168	0.7%	589
2009	405,144	0.7%	12,688	5,141	-0.5%	586
2010	407,551	0.6%	12,421	5,062	-1.5%	578
2011	409,786	0.5%	12,361	5,066	0.1%	577
2012	413,610	0.9%	12,251	5,067	0.0%	576
2013	418,892	1.3%	11,968	5,013	-1.1%	575
2014	425,036	1.5%	11,873	5,047	0.7%	573
2015	432,275	1.7%	11,558	4,996	-1.0%	572
2016	440,362	1.9%	11,515	5,071	1.5%	579

Projected Residential Sales and Load, 2017–2036

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2017	448,947	1.9%	11,565	5,192	2.4%	594
2018	458,024	2.0%	11,546	5,288	1.8%	605
2019	467,730	2.1%	11,518	5,388	1.9%	615
2020	477,773	2.1%	11,372	5,433	0.8%	619
2021	487,898	2.1%	11,260	5,494	1.1%	628
2022	498,339	2.1%	11,212	5,588	1.7%	639
2023	509,058	2.2%	11,159	5,681	1.7%	649
2024	519,642	2.1%	11,092	5,764	1.5%	657
2025	529,711	1.9%	11,000	5,827	1.1%	666
2026	539,237	1.8%	10,921	5,889	1.1%	673
2027	548,388	1.7%	10,882	5,967	1.3%	682
2028	557,228	1.6%	10,843	6,042	1.3%	688
2029	565,899	1.6%	10,792	6,107	1.1%	698
2030	574,448	1.5%	10,731	6,165	0.9%	704
2031	582,924	1.5%	10,666	6,218	0.9%	710
2032	591,436	1.5%	10,588	6,262	0.7%	713
2033	600,040	1.5%	10,544	6,327	1.0%	723
2034	608,899	1.5%	10,510	6,399	1.1%	731
2035	617,979	1.5%	10,474	6,473	1.1%	740
2036	627,295	1.5%	10,452	6,557	1.3%	747

Commercial Load

Historical Commercial Sales and Load, 1976–2016 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1976	26,034	–	52,519	1,367	–	157
1977	27,112	4.1%	52,402	1,421	3.9%	162
1978	27,831	2.7%	52,502	1,461	2.8%	169
1979	28,087	0.9%	56,369	1,583	8.4%	180
1980	28,797	2.5%	54,161	1,560	-1.5%	178
1981	29,567	2.7%	54,302	1,606	2.9%	184
1982	30,167	2.0%	54,124	1,633	1.7%	186
1983	30,776	2.0%	52,650	1,620	-0.8%	185
1984	31,554	2.5%	53,560	1,690	4.3%	193
1985	32,418	2.7%	54,180	1,756	3.9%	201
1986	33,208	2.4%	53,937	1,791	2.0%	204
1987	33,975	2.3%	53,395	1,814	1.3%	207
1988	34,723	2.2%	54,371	1,888	4.1%	216
1989	35,638	2.6%	55,376	1,973	4.5%	226
1990	36,785	3.2%	55,746	2,051	3.9%	235
1991	37,922	3.1%	56,273	2,134	4.1%	244
1992	39,022	2.9%	56,396	2,201	3.1%	251
1993	40,047	2.6%	58,183	2,330	5.9%	266
1994	41,629	4.0%	58,274	2,426	4.1%	278
1995	43,165	3.7%	58,695	2,534	4.4%	290
1996	44,995	4.2%	62,013	2,790	10.1%	319
1997	46,819	4.1%	62,056	2,905	4.1%	332
1998	48,404	3.4%	62,718	3,036	4.5%	348
1999	49,430	2.1%	64,170	3,172	4.5%	362
2000	50,117	1.4%	65,965	3,306	4.2%	378
2001	51,501	2.8%	67,426	3,472	5.0%	396
2002	52,915	2.7%	64,794	3,429	-1.3%	392
2003	54,194	2.4%	64,254	3,482	1.6%	398
2004	55,577	2.6%	63,942	3,554	2.1%	405
2005	57,145	2.8%	63,504	3,629	2.1%	415
2006	59,050	3.3%	63,484	3,749	3.3%	429
2007	61,640	4.4%	63,352	3,905	4.2%	446
2008	63,492	3.0%	62,246	3,952	1.2%	449
2009	64,151	1.0%	59,671	3,828	-3.1%	438
2010	64,421	0.4%	58,853	3,791	-1.0%	432
2011	64,921	0.8%	58,431	3,793	0.1%	433
2012	65,599	1.0%	58,896	3,863	1.8%	440
2013	66,357	1.2%	58,599	3,888	0.6%	446
2014	67,113	1.1%	58,948	3,956	1.7%	452
2015	68,000	1.3%	58,491	3,977	0.5%	455
2016	68,883	1.3%	58,046	3,998	0.5%	456

Projected Commercial Sales and Load, 2017–2036

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2017	69,911	1.5%	58,311	4,077	2.0%	466
2018	71,070	1.7%	58,026	4,124	1.2%	471
2019	72,344	1.8%	57,526	4,162	0.9%	475
2020	73,720	1.9%	56,864	4,192	0.7%	477
2021	75,165	2.0%	56,200	4,224	0.8%	482
2022	76,660	2.0%	55,523	4,256	0.8%	486
2023	78,208	2.0%	54,833	4,288	0.8%	490
2024	79,791	2.0%	54,094	4,316	0.6%	492
2025	81,371	2.0%	53,395	4,345	0.7%	496
2026	82,914	1.9%	52,797	4,378	0.8%	500
2027	84,419	1.8%	52,229	4,409	0.7%	503
2028	85,894	1.7%	51,648	4,436	0.6%	505
2029	87,350	1.7%	51,172	4,470	0.8%	510
2030	88,792	1.7%	50,689	4,501	0.7%	514
2031	90,227	1.6%	50,214	4,531	0.7%	517
2032	91,661	1.6%	49,753	4,560	0.7%	519
2033	93,103	1.6%	49,335	4,593	0.7%	525
2034	94,563	1.6%	48,928	4,627	0.7%	528
2035	96,046	1.6%	48,546	4,663	0.8%	533
2036	97,553	1.6%	48,191	4,701	0.8%	535

Irrigation Load

Historical Irrigation Sales and Load, 1976–2016 (weather adjusted)

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1976	9,936	–	157,590	1,566	–	178
1977	10,238	3.0%	163,580	1,675	7.0%	191
1978	10,476	2.3%	154,417	1,618	-3.4%	185
1979	10,711	2.2%	164,233	1,759	8.7%	201
1980	10,854	1.3%	160,661	1,744	-0.9%	199
1981	11,248	3.6%	167,476	1,884	8.0%	215
1982	11,312	0.6%	154,133	1,744	-7.4%	199
1983	11,133	-1.6%	147,254	1,639	-6.0%	187
1984	11,375	2.2%	136,431	1,552	-5.3%	177
1985	11,576	1.8%	133,886	1,550	-0.1%	177
1986	11,308	-2.3%	133,605	1,511	-2.5%	172
1987	11,254	-0.5%	132,650	1,493	-1.2%	170
1988	11,378	1.1%	137,485	1,564	4.8%	178
1989	11,957	5.1%	137,849	1,648	5.4%	188
1990	12,340	3.2%	149,397	1,844	11.8%	210
1991	12,484	1.2%	138,862	1,734	-6.0%	198
1992	12,809	2.6%	141,889	1,817	4.8%	207
1993	13,078	2.1%	131,086	1,714	-5.7%	196
1994	13,559	3.7%	132,337	1,794	4.7%	205
1995	13,679	0.9%	128,923	1,764	-1.7%	201
1996	14,074	2.9%	126,199	1,776	0.7%	202
1997	14,383	2.2%	120,399	1,732	-2.5%	198
1998	14,695	2.2%	120,340	1,768	2.1%	202
1999	14,912	1.5%	120,589	1,798	1.7%	205
2000	15,253	2.3%	128,659	1,962	9.1%	223
2001	15,522	1.8%	117,561	1,825	-7.0%	208
2002	15,840	2.0%	109,186	1,730	-5.2%	197
2003	16,020	1.1%	111,786	1,791	3.5%	204
2004	16,297	1.7%	109,191	1,779	-0.6%	203
2005	16,936	3.9%	102,141	1,730	-2.8%	197
2006	17,062	0.7%	96,870	1,653	-4.5%	189
2007	17,001	-0.4%	105,466	1,793	8.5%	205
2008	17,428	2.5%	109,423	1,907	6.4%	217
2009	17,708	1.6%	101,814	1,803	-5.5%	206
2010	17,846	0.8%	101,998	1,820	1.0%	208
2011	18,292	2.5%	99,885	1,827	0.4%	209
2012	18,675	2.1%	104,064	1,943	6.4%	221
2013	19,017	1.8%	103,977	1,977	1.7%	226
2014	19,328	1.6%	104,762	2,025	2.4%	231
2015	19,756	2.2%	95,595	1,889	-6.7%	213
2016	20,042	1.4%	96,320	1,930	2.2%	220

Projected Irrigation Sales and Load, 2017–2036

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2017	20,322	1.4%	95,100	1,933	0.1%	221
2018	20,623	1.5%	94,261	1,944	0.6%	222
2019	20,914	1.4%	93,667	1,959	0.8%	224
2020	21,211	1.4%	92,910	1,971	0.6%	224
2021	21,508	1.4%	92,038	1,980	0.4%	226
2022	21,806	1.4%	91,417	1,993	0.7%	228
2023	22,102	1.4%	90,745	2,006	0.6%	229
2024	22,393	1.3%	90,067	2,017	0.6%	230
2025	22,691	1.3%	89,332	2,027	0.5%	231
2026	22,988	1.3%	88,614	2,037	0.5%	233
2027	23,285	1.3%	88,060	2,050	0.7%	234
2028	23,581	1.3%	87,483	2,063	0.6%	235
2029	23,877	1.3%	86,865	2,074	0.5%	237
2030	24,172	1.2%	86,305	2,086	0.6%	238
2031	24,469	1.2%	85,740	2,098	0.6%	239
2032	24,766	1.2%	85,113	2,108	0.5%	240
2033	25,062	1.2%	84,622	2,121	0.6%	242
2034	25,356	1.2%	84,178	2,134	0.6%	244
2035	25,651	1.2%	83,720	2,148	0.6%	245
2036	25,946	1.2%	83,336	2,162	0.7%	246

Industrial Load

Historical Industrial Sales and Load, 1976–2016 (not weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1976	73	–	11,681,540	858	–	99
1977	85	15.1%	10,988,826	929	8.3%	106
1978	99	17.6%	9,786,753	972	4.7%	111
1979	109	9.6%	9,989,158	1,087	11.8%	126
1980	112	2.7%	9,894,706	1,106	1.7%	125
1981	118	5.7%	9,718,723	1,148	3.9%	132
1982	122	3.5%	9,504,283	1,162	1.2%	133
1983	122	-0.3%	9,797,522	1,194	2.7%	138
1984	124	1.5%	10,369,789	1,282	7.4%	147
1985	125	1.2%	10,844,888	1,357	5.9%	155
1986	129	2.7%	10,550,145	1,357	-0.1%	155
1987	134	4.1%	11,006,455	1,474	8.7%	169
1988	133	-1.0%	11,660,183	1,546	4.9%	177
1989	132	-0.6%	12,091,482	1,594	3.1%	183
1990	132	0.2%	12,584,200	1,662	4.3%	191
1991	135	2.5%	12,699,665	1,719	3.4%	196
1992	140	3.4%	12,650,945	1,770	3.0%	203
1993	141	0.5%	13,179,585	1,854	4.7%	212
1994	143	1.7%	13,616,608	1,948	5.1%	223
1995	120	-15.9%	16,793,437	2,021	3.7%	230
1996	103	-14.4%	18,774,093	1,934	-4.3%	221
1997	106	2.7%	19,309,504	2,042	5.6%	235
1998	111	4.6%	19,378,734	2,145	5.0%	244
1999	108	-2.3%	19,985,029	2,160	0.7%	247
2000	107	-0.8%	20,433,299	2,191	1.5%	250
2001	111	3.5%	20,618,361	2,289	4.4%	260
2002	111	-0.1%	19,441,876	2,156	-5.8%	246
2003	112	1.0%	19,950,866	2,234	3.6%	255
2004	117	4.3%	19,417,310	2,269	1.5%	259
2005	126	7.9%	18,645,220	2,351	3.6%	270
2006	127	1.0%	18,255,385	2,325	-1.1%	265
2007	123	-3.6%	19,275,551	2,366	1.8%	270
2008	119	-3.1%	19,412,391	2,308	-2.4%	261
2009	124	4.0%	17,987,570	2,224	-3.6%	254
2010	121	-2.0%	18,404,875	2,232	0.3%	254
2011	120	-1.1%	18,597,050	2,230	-0.1%	254
2012	115	-4.2%	19,757,921	2,271	1.8%	258
2013	114	-0.7%	20,281,837	2,314	1.9%	265
2014	113	-0.7%	20,863,653	2,363	2.1%	271
2015	116	2.8%	20,271,082	2,360	-0.1%	269
2016	118	1.4%	19,997,106	2,361	0.1%	270

Projected Industrial Sales and Load, 2017–2036

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2017	119	0.8%	20,602,815	2,452	3.8%	281
2018	120	0.8%	21,033,767	2,524	2.9%	288
2019	121	0.8%	21,161,810	2,561	1.4%	293
2020	121	0.0%	21,372,860	2,586	1.0%	295
2021	121	0.0%	21,497,289	2,601	0.6%	297
2022	122	0.8%	21,426,910	2,614	0.5%	299
2023	123	0.8%	21,375,415	2,629	0.6%	300
2024	124	0.8%	21,318,605	2,644	0.5%	301
2025	125	0.8%	21,253,784	2,657	0.5%	303
2026	125	0.0%	21,355,032	2,669	0.5%	305
2027	127	1.6%	21,124,323	2,683	0.5%	306
2028	128	0.8%	21,082,969	2,699	0.6%	307
2029	128	0.0%	21,208,625	2,715	0.6%	310
2030	128	0.0%	21,329,641	2,730	0.6%	312
2031	129	0.8%	21,284,186	2,746	0.6%	314
2032	130	0.8%	21,226,438	2,759	0.5%	314
2033	130	0.0%	21,325,215	2,772	0.5%	317
2034	131	0.8%	21,268,565	2,786	0.5%	318
2035	133	1.5%	21,054,677	2,800	0.5%	320
2036	133	0.0%	21,155,835	2,814	0.5%	320

Additional Firm Sales and Load
Historical Additional Firm Sales and Load, 1976–2016

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1976	288	–	33
1977	311	7.8%	35
1978	357	14.8%	41
1979	373	4.4%	43
1980	360	-3.5%	41
1981	376	4.6%	43
1982	367	-2.4%	42
1983	425	15.7%	49
1984	466	9.7%	53
1985	471	1.1%	54
1986	482	2.4%	55
1987	502	4.2%	57
1988	530	5.6%	60
1989	671	26.5%	77
1990	625	-6.9%	71
1991	661	5.8%	75
1992	680	2.9%	77
1993	689	1.3%	79
1994	740	7.5%	85
1995	878	18.6%	100
1996	989	12.6%	113
1997	1,048	6.0%	120
1998	1,113	6.2%	127
1999	1,121	0.8%	128
2000	1,143	1.9%	130
2001	1,118	-2.1%	128
2002	1,139	1.9%	130
2003	1,120	-1.7%	128
2004	1,156	3.3%	132
2005	1,175	1.6%	134
2006	1,189	1.2%	136
2007	1,141	-4.0%	130
2008	1,114	-2.4%	127
2009	965	-13.4%	110
2010	907	-6.0%	103
2011	906	0.0%	103
2012	862	-4.8%	98
2013	867	0.5%	99
2014	841	-2.9%	96
2015	842	0.1%	96
2016	870	3.3%	99

*Includes Micron Technology, Simplot Fertilizer, INL, Hoku Materials, City of Weiser, and Raft River Rural Electric Cooperative, Inc.

Projected Additional Firm Sales and Load, 2017–2036

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2017	945	8.6%	108
2018	962	1.7%	110
2019	972	1.1%	111
2020	979	0.7%	111
2021	983	0.4%	112
2022	990	0.8%	113
2023	1,011	2.1%	115
2024	1,084	7.2%	123
2025	1,086	0.2%	124
2026	1,086	-0.1%	124
2027	1,087	0.1%	124
2028	1,089	0.2%	124
2029	1,088	-0.1%	124
2030	1,088	0.0%	124
2031	1,088	0.0%	124
2032	1,089	0.1%	124
2033	1,090	0.1%	124
2034	1,090	0.0%	124
2035	1,092	0.2%	125
2036	1,092	0.0%	124

*Includes Micron Technology, Simplot Fertilizer, and the INL

Company System Load (excluding Astaris)
Historical Company System Sales and Load, 1976–2016 (weather adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1976	6,413	–	799
1977	6,778	5.7%	848
1978	7,242	6.8%	899
1979	7,624	5.3%	955
1980	7,842	2.8%	971
1981	8,129	3.7%	1,009
1982	7,841	-3.5%	976
1983	8,019	2.3%	997
1984	8,125	1.3%	1,007
1985	8,285	2.0%	1,030
1986	8,341	0.7%	1,034
1987	8,478	1.6%	1,053
1988	8,814	4.0%	1,092
1989	9,209	4.5%	1,143
1990	9,568	3.9%	1,190
1991	9,756	2.0%	1,209
1992	9,990	2.4%	1,238
1993	10,235	2.5%	1,270
1994	10,657	4.1%	1,324
1995	11,062	3.8%	1,371
1996	11,414	3.2%	1,413
1997	11,746	2.9%	1,458
1998	12,211	4.0%	1,513
1999	12,491	2.3%	1,548
2000	12,911	3.4%	1,599
2001	13,050	1.1%	1,613
2002	12,748	-2.3%	1,580
2003	13,053	2.4%	1,618
2004	13,327	2.1%	1,651
2005	13,618	2.2%	1,692
2006	13,910	2.2%	1,725
2007	14,339	3.1%	1,779
2008	14,449	0.8%	1,784
2009	13,961	-3.4%	1,732
2010	13,812	-1.1%	1,712
2011	13,822	0.1%	1,713
2012	14,007	1.3%	1,732
2013	14,060	0.4%	1,750
2014	14,232	1.2%	1,763
2015	14,064	-1.2%	1,742
2016	14,231	1.2%	1,762

Company System Load

Projected Company System Sales and Load, 2017–2036

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2017	14,598	2.6%	1,810
2018	14,842	1.7%	1,840
2019	15,041	1.3%	1,864
2020	15,161	0.8%	1,874
2021	15,282	0.8%	1,894
2022	15,442	1.0%	1,914
2023	15,615	1.1%	1,935
2024	15,824	1.3%	1,955
2025	15,941	0.7%	1,975
2026	16,059	0.7%	1,990
2027	16,196	0.9%	2,007
2028	16,329	0.8%	2,018
2029	16,454	0.8%	2,039
2030	16,570	0.7%	2,053
2031	16,680	0.7%	2,067
2032	16,779	0.6%	2,074
2033	16,903	0.7%	2,095
2034	17,037	0.8%	2,112
2035	17,175	0.8%	2,129
2036	17,326	0.9%	2,142