Appendix A—Sales and Load Forecast

For the 2011 Integrated Resource Plan

June 2011

IDAHO POWER
An IDACORP Company

TABLE OF CONTENTS

Table of Contents i
List of Tables ii
List of Figures ii
List of Appendices iii
Introduction 1
2011 IRP Sales and Load Forecast 3
 Average Load 3
 Peak-Hour Demands 4
Overview of the Forecast 7
 Fuel Prices 7
 Electric Vehicles 10
 Forecast Probabilities 11
  Load Forecasts Based on Weather Variability 11
  Load Forecasts Based on Economic Uncertainty 13
Residential 17
Commercial 19
Irrigation 21
Industrial 23
Additional Firm Load 25
 Micron Technology 26
 Simplot Fertilizer 26
 Idaho National Laboratory 26
 Hoku Materials 27
 "Special" Contract 27
 Raft River Rural Electric Cooperative 27
Company System Peak 29
Company System Load 31
Contract Off-System Load 33
Total Company Load 35
Demand-Side Management 37
 Energy Efficiency Programs 37
 Demand Response Programs 38

LIST OF TABLES

Table 1. Residential fuel-price escalation (2011–2030) 8
Table 2. Average load and peak-demand forecast scenarios 12
Table 3. Forecast probabilities 14
Table 4. System load growth 14
Table 5. Residential load growth 17
Table 6. Commercial load growth 19
Table 7. Irrigation load growth 21
Table 8. Industrial load growth 23
Table 9. Additional firm load growth 25
Table 10. System summer peak load growth 29
Table 11. System winter peak load growth 30
Table 12. System load growth 31

LIST OF FIGURES

Figure 1. Forecasted electricity prices 9
Figure 2. Forecasted residential natural gas prices 10
Figure 3. Electric vehicles 11
Figure 4. Forecasted system load 15
Figure 5. Forecasted residential load 17
Figure 6. Forecasted residential-use-per-customer 18
Figure 7. Forecasted commercial load 19
Figure 8. Forecasted commercial-use-per-customer 20
Figure 9. Forecasted irrigation load 21
Figure 10. Forecasted industrial load 23
Figure 11. Industrial electricity consumption by industry group 24
Figure 12. Forecasted additional firm load 26
Figure 13. Forecasted system summer peak 29
Figure 14. Forecasted system winter peak 30
Figure 15. Forecasted system load 31
Figure 16. Composition of total company electricity sales 35

LIST OF APPENDICES

Appendix A1. Historical and Projected Sales and Load 39
Residential Load 39
Historical Residential Sales and Load, 1970–2010 39
Projected Residential Sales and Load, 2011–2030 40
Commercial Load 41
Historical Commercial Sales and Load, 1970–2010 41
Projected Commercial Sales and Load, 2011–2030 42
Irrigation Load 43
Historical Irrigation Sales and Load,1970–2010 43
Projected Irrigation Sales and Load, 2011–2030 44
Industrial Load 45
Historical Industrial Sales and Load, 1970–2010 45
Projected Industrial Sales and Load, 2011–2030 46
Additional Firm Sales and Load* 47
Historical Additional Firm Sales and Load, 1970–2010 47
Projected Additional Firm Sales and Load, 2011–2030 48
Company System Load (excluding Astaris) 49
Historical Company System Sales and Load, 1970–2010 49
Company System Load (including Astaris) 50
Historical Company System Sales and Load, 1970–2010 50
Astaris Sales and Load (1970–2002) 50
Projected Company System Sales and Load, 2011–2030 51
Contract Off-System Load 52
Historical Contract Off-System Sales and Load, 1970–2010 52
Projected Contract Off-System Sales and Load, 2011–2030 52
Total Company Load 53
Historical Total Company Sales and Load, 1970–2010 53
Projected Total Company Sales and Load, 2011–2030 54

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INTRODUCTION

Idaho Power has prepared *Appendix A–Sales and Load Forecast* as an appendix to its *2011 Integrated Resource Plan* (IRP). The sales and load forecast is Idaho Power's best estimate of the future demand for electricity within the company's service area. The forecast covers the 20-year period from 2011 through 2030.

The expected-case monthly average load forecast represents Idaho Power's estimate of the most probable outcome for load growth during the planning period and is based on the most recent economic forecast for Idaho Power's service area. However, the actual path of future electricity sales will not follow the exact path suggested by the expected-case load forecast. Therefore, four additional load forecasts were prepared, two that provide a range of possible load growths due to economic uncertainty, and two that address the load variability associated with abnormal weather. The high- and low-growth scenarios provide a range of possible load growths over the planning period due to variable economic, demographic, and other non-weather-related influences. The high-growth and low-growth scenarios were prepared based on statistical analyses to empirically reflect uncertainty inherent in the load forecast. The 70th percentile and 90th percentile load forecast scenarios were developed to assist Idaho Power in reviewing the resource requirements that would result from higher loads due to more adverse weather conditions.

The expected-case load forecast assumes median temperatures and median rainfall. Since actual loads can vary significantly, dependent on weather conditions, two alternative scenarios were considered to address the load variability due to weather. A 70th percentile average load forecast and 90th percentile average load forecast were prepared to illustrate the weather-related uncertainty inherent in forecasting electrical loads. The 70th percentile load forecast assumes monthly loads that can be exceeded in three-out-of-ten years (30 percent of the time). The 90th percentile load forecast assumes monthly loads that can be exceeded in one-out-of-ten years (10 percent of the time).

In the expected-case scenario, Idaho Power's system load is forecast to increase to 2,362 average megawatts (aMW) in the year 2030 from the 2011 forecast load of 1,819 aMW. The expected-case forecast system load growth rate averages 1.4 percent per year over the 20 years of the planning period (2011–2030). In the more critical 70th percentile load forecast, used for resource planning, the system load is forcasted to read 2,414 aMW. Idaho Power system peak load (95th percentile) is forecast to grow to 4,901 megawatts (MW) in the year 2030 from the 2008 actual system summer peak of 3,214 MW. The highest system peak on record was 3,214 MW and occurred on Monday, June 30, 2008, at 3:00 p.m. In the expected-case scenario, Idaho Power system peak increases at an average growth rate of 1.8 percent per year over the 20 years of the planning period (2011–2030). The number of Idaho Power active retail customers increased from the December 2010 level of 490,869 customers to over 653,000 customers at year-end 2030.

This year's economic forecast was based on a forecast of national and regional economic activity developed by Moody's Analytics, Inc., a national econometric consulting firm. Moody's Analytics, Inc., July 2010 macroeconomic forecast strongly influenced *Appendix A–Sales and Load Forecast*. The national, state, metropolitan statistical area (MSA), and county econometric projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. Specific demographic projections are also developed for the service area from national and local census data. National economic drivers from Moody's Analytics, Inc., were also used in development of *Appendix A–Sales and Load Forecast*.

Economic growth assumptions influence several of the individual class of service growth rates. The number of households in Idaho is projected to grow at an annual average rate of 1.2 percent during the forecast period. Growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service area households are derived from county-specific household forecasts. The number of households, incomes, employment projections, 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 specific assumptions were incorporated in the forecasts of the individual sectors. Further discussion of the assumptions is presented in the sections of this report pertaining to the individual sectors.

The future load impacts of implemented and committed Idaho Power energy efficiency demand-side management (DSM) programs are considered within *Appendix A–Sales and Load Forecast*. These programs and their expected impacts are addressed in more detail in Idaho Power's *Demand-Side Management 2010 Annual Report*. This report is Appendix B to the 2011 IRP.

During the 20-year forecast horizon, there could be major changes in the electric utility industry, such as the impact of a wide-range of possible carbon scenarios and the subsequent potential for much higher electricity prices impacting future electricity demand. In addition, the price and volatility of substitute fuels, such as natural gas, might also impact the future demand for electricity. The high degree of uncertainty associated with such changes is assumed to be reflected in the economic high- and low-load growth scenarios previously described. However, due to the possibility of proposed carbon legislation becoming law, the impact of carbon legislation on the load forecast was reflected in the forecast of retail electricity prices, which is a driver in the major sector sales forecasting models. The alternative sales and load scenarios of *Appendix A–Sales and Load Forecast* were prepared under the assumption that Idaho Power will continue to serve all customers in its franchised service area during the planning period.

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

2011 IRP Sales and Load Forecast

Average Load

The 2011 IRP average system load forecast is lower initially than the 2009 IRP average system load forecast. However, after 2015, the 2011 IRP forecast is higher in all remaining years of the forecast period . The recovery in the national and service-area economy is expected to cause load growth to steadily revive. In addition, the lowered expectations in existing and committed energy efficiency measures, combined with retail electricity prices that incorporate much-reduced impact of carbon on Idaho Power's retail electricity prices, result in an increase of forecast average loads. Significant factors and considerations that influenced the outcome of the 2011 IRP load forecast include the following:

- The retail electricity price forecast used to prepare the *Appendix A–Sales and Load Forecast* in the 2009 IRP reflected the fixed and variable costs of integrating the resources identified by the 2006 IRP preferred portfolio, including the expected cost of carbon emissions. When compared to the electricity price forecast used to prepare the *Appendix A–Sales and Load Forecast*, the 2009 IRP price forecast yielded significantly higher future electricity prices. The price forecast difference is primarily the result of differing carbon cost assumptions between the two forecasts. The 2009 IRP retail electricity price forecast assumed a carbon tax scenario (from the 2006 IRP), and the 2011 IRP electricity price forecast assumed a cap-and-trade carbon scenario (from the 2009 IRP). Under the cap-and-trade carbon scenario, Idaho Power curtailed carbon emissions from coal units to comply with target emissions. The carbon assumptions from the 2006 IRP is the driver for the 2011 IRP's retail electricity price forecasts.
- The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special-contract customer, Hoku Materials, located in Pocatello, Idaho. At the time this forecast was completed (August 2010), Hoku Materials planned to begin operation in January 2011 and will reach full capacity by April 2011. The current sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses) once continuous operation is reached in 2013.
- The load forecast used for the 2011 IRP reflects a recovery in the service area economy following a severe recession in 2008 and 2009, as well as a much smaller impact of carbon regulation on future energy rates charged to Idaho Power retail customers. Both factors resulted in a higher long-term load forecast than was used in the 2009 IRP. The collapse in the housing sector in 2008 and 2009 dramatically slowed the growth in the number of new households and residential customers being added to Idaho Power's service area. In addition, the number of commercial customers being added also slowed dramatically as a result of the economic downturn. However, by 2012, residential and commercial customer growth is expected to recover; and by 2015, customer additions are forecast to approach the growth that occurred prior to the housing bubble (2000–2004).
- In this year's forecast, an additional customer referred to in this document as "Special" was included in the Additional Firm Load category, even though a long-term contract had not yet been fully executed. At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined that the real possibility of the new large load was significant enough that it would be imprudent of the company to ignore the possible impact. The anticipated load of the new "Special" contract has been included in this

forecast based on discussions with the interested parties. The existing special contracts and the new "Special" contract together make up the Additional Firm Load category.

- There continues to be significant uncertainty associated with the growth of new industrial and special contract customers and their potential impact on the load forecast. The forecast uncertainty is associated with the increasing number of entities that have contacted Idaho Power and expressed interest in locating their operations within Idaho Power's service area and the unknown magnitude of the energy and peak-demand requirements. The current sales and load forecast reflects only those customers that have a very high probability of relocating to the service area or have made financial commitments and whose facilities are actually being constructed at this time. Therefore, the large numbers of businesses that have contacted Idaho Power and shown interest, but have not made commitments, are not included in the current sales and load forecast.
- In another improvement to this year's forecast, Idaho Power used Itron's residential Statistically Adjusted End-Use (SAE) model to prepare the long-term residential sales forecast. Recently, many utilities have adopted Itron's SAE modeling approach to include greater end-use information into the forecast process.
- Existing energy efficiency program performance is estimated and included in the sales and load forecast base, lowering the energy and peak demand forecast. However, the impact of demand response programs is accounted for in the IRP load and resource balance. The amount of committed and implemented DSM programs for each month of the planning period is shown in the IRP load and resource balance in *Appendix C–Technical Appendix*.
- A somewhat higher irrigation sales forecast is expected, compared to earlier forecasts (prior to the 2009 IRP) due to a substantial increase in weather-adjusted irrigation sales in 2007 and 2008 (6% in 2007 and 8% in 2008). Higher farm commodity prices appear to be the primary reason behind the irrigation sales increase. Farmers appear to have taken advantage of the commodities market by planting all available acreage. In addition, the conversion of hand line to electrically operated pivot irrigation systems may explain a part of the increased energy consumption. In recent years, the increased labor costs associated with moving hand lines and increased concerns for water conservation has triggered the substitution of labor with electrically operated pivots.

Peak-Hour Demands

Peak day temperatures and the growth in average loads drive the peak forecasting model regressions. The peak forecast results and comparisons with previous forecasts differ for a number of reasons that include the following:

- This year's peak forecast also reflects the increased expected peak demand of an additional "Special" contract customer. The anticipated peak load of the new contract has been included in this year's forecast based on discussions with the interested parties.
- The 2011 IRP peak-demand forecast was adjusted downward to reflect the estimated impact of energy efficiency DSM programs selected for implementation since 2001. Energy efficiency programs are incorporated into the peak-demand forecast as the programs are committed and implemented.
- The 2011 IRP peak demand forecast model does not consider or adjust for the impact of demand response programs. The demand response programs are accounted for in the IRP load and resource balance as a reduction in peak demand.

- The peak model allows peaks to be calculated at the 50th, 90th, and 95th percentiles of peak day temperatures for each month of the year.
- Recent historical peak data is added to the peak model regressions. The July 2002, July 2003, June 2005, and July 2005 peak day temperatures were near the 100th percentile, and their addition to the regression models impacted forecast results. In addition, new system peaks were reached in July 2007 and again in June 2008 and were incorporated into the peak forecast model regressions.
- Idaho Power continues to use a median peak day temperature driver in lieu of an average peak day temperature driver. 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. The weighted average peak day temperature drivers are calculated over the 1980–2009 time period (the most recent 30 years).

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OVERVIEW OF THE FORECAST

The sales and load forecast is constructed by developing a separate forecast for each individual sales category. Independent sales forecasts are prepared for each of the major customer classes: residential, commercial, irrigation, and industrial. Individual energy and peak-demand forecasts are developed for special contract customers, including Micron Technology, Inc., (Micron Technology), Simplot Fertilizer Company (Simplot Fertilizer), Idaho National Laboratory (INL), Hoku Materials, one additional high-probability special contract customer (referred to as "Special"), and Raft River Rural Electric Cooperative, Inc. (Raft River)—the electric distribution utility serving Idaho Power's former customers in Nevada. These six, special contract customers are combined into a single forecast category labeled Additional Firm Load. In the 2009 IRP sales and load forecast, the "Special" contract load was combined with the industrial sector (Schedule 19) load forecast. Given the magnitude of their expected future load, the "Special" contract has now been combined with the other larger special contract customers that have monthly metered demands greater than 20,000 kilowatts (kW). Lastly, the contract off-system category represents long-term contracts to supply firm energy and demand to off-system customers. At this time, there are no long-term contracts. The assumptions for each of the individual categories are described in greater detail in the respective sections.

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

Loss factors are determined by Idaho Power's Distribution Planning department. The annual-average energy loss coefficients are multiplied by the calendar-month load, yielding the system load, including losses.

The peak-load forecast was prepared in conjunction with the 2011 sales forecast. Idaho Power has two distinct peak periods: 1) a winter peak, resulting 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. The summer peak generally occurs when extensive air conditioning usage coincides with significant irrigation demand.

Peak loads are forecast using 12 regression equations and are a function of average peak day temperatures, historical monthly average load, and precipitation (summer only). The peak forecast uses statistically derived peak day temperatures based on the most recent 30 years of climate data for each month. Peak loads for the INL, Micron Technology, Simplot Fertilizer, Hoku Materials, Idaho Power's newest "Special" contract customer, and Raft River are forecast based on historical analysis and contractual considerations.

The primary external factors in the forecast are macroeconomic and demographic data. Moody's Analytics provides the macroeconomic forecasts. The national, state, MSA, and county economic and demographic projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. Specific demographic projections are also developed for the service area from national and local census data.

Fuel Prices

Fuel prices, in combination with service area economic drivers, impact long-term trends in electricity sales. Changes in relative fuel prices can also have significant impacts on the future demand for electricity. The sales and load forecast is also influenced by the estimated impact of proposed carbon legislation on retail electricity prices. The carbon-impacted retail electricity prices move higher throughout the forecast period, reducing future electricity sales. Class level and economic-sector level regression models were used to identify the relationships between real historical electricity prices and 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 1. 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 1. Residential fuel-price escalation (2011–2030)
(average annual percent change)

	Nominal	Real*
Electricity–2011 IRP–Carbon	2.6%	0.9%
Electricity–2009 IRP–Carbon	5.1%	3.2%
Natural Gas	2.5%	0.8%

*adjusted for inflation

Figure 1 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1970–2010 and over the forecast period 2011–2030. Both nominal and real prices are shown. In the 2011 IRP carbon scenario, nominal electricity prices are expected to slowly climb to nearly 13 cents per kilowatt-hour (kWh) by the end of the forecast period in 2030. Real electricity prices (inflation adjusted) in the carbon scenario are expected to increase over the forecast period at an average rate of 0.9 percent each year. In the 2009 IRP electricity price carbon scenario, nominal electricity prices were assumed to climb to nearly 22 cents per kWh by 2030, and real electricity prices (inflation adjusted) were expected to increase over the forecast period at an average rate of 3.2 percent each year. The impact of the much higher electricity price forecast on the 2009 IRP load forecast was significant and served to slow the growth in electricity sales, especially in the last 10 years of the forecast period.

The electricity price forecast used to prepare the sales and load forecast in the 2009 IRP reflected the fixed and variable costs of integrating the resources identified by the 2006 IRP preferred portfolio, including the expected costs of carbon emissions. When compared to the electricity price forecast used to prepare the 2011 IRP sales and load forecast, the 2009 IRP price forecast yielded significantly higher future prices. The price forecast difference is primarily the result of differing carbon cost assumptions between the two forecasts. The 2009 IRP retail electricity price forecast assumed a carbon tax scenario (from the 2006 IRP), and the 2011 IRP electricity price forecast assumed a cap-and-trade carbon scenario (from the 2009 IRP). Under the cap-and-trade carbon scenario, Idaho Power curtailed carbon emissions from coal units to comply with target emissions.

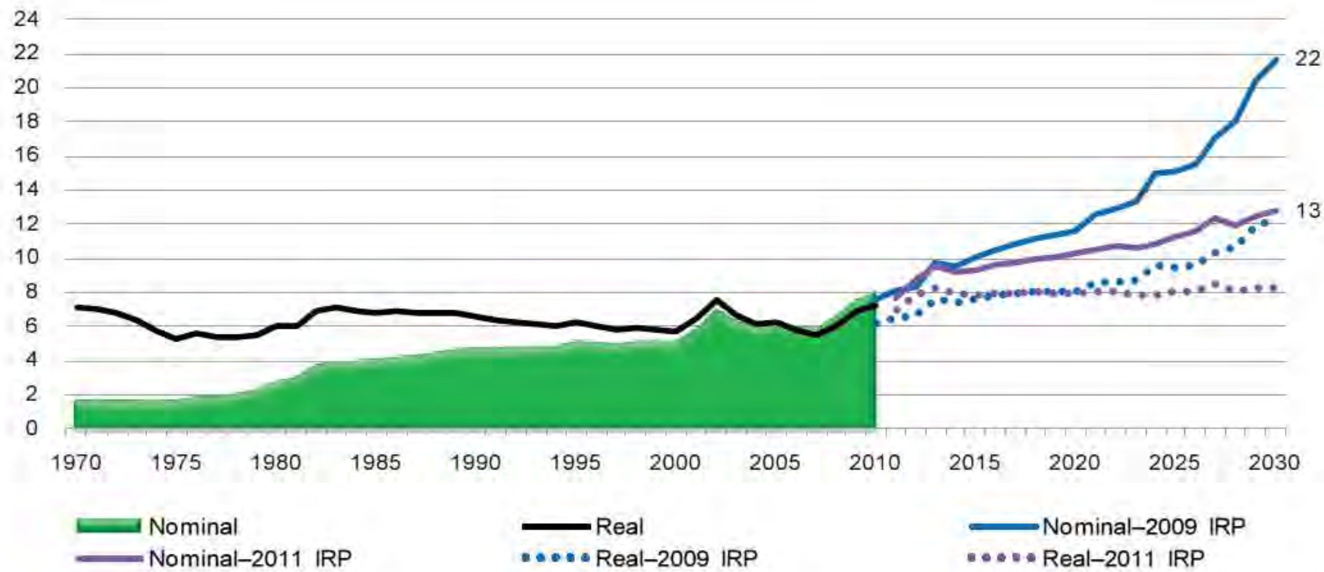

Figure 1. Forecasted electricity prices
(cents per kWh)

Electricity prices for Idaho Power customers moved significantly higher 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. Over the 1990–2000 period, electricity prices rose only 8 percent overall, an annual average compound growth rate of 0.8 percent each year.

Figure 2 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1970–2009, and forecast prices from 2010–2030. 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 again moving sharply upward in 2004, 2005, and 2006. Natural gas prices moved downward in 2010, reflecting the collapse in natural gas prices that began in 2009. After bottoming in 2010, nominal natural gas prices are expected to rise in 2011, plateau through 2014, and then slowly rise throughout the remainder of the forecast period. Natural gas prices at the end of the forecast period are expected to be about 40 percent higher than 2009, growing at an average rate of 2.5 percent per year over the forecast period (2011–2030). Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 0.8 percent each year.

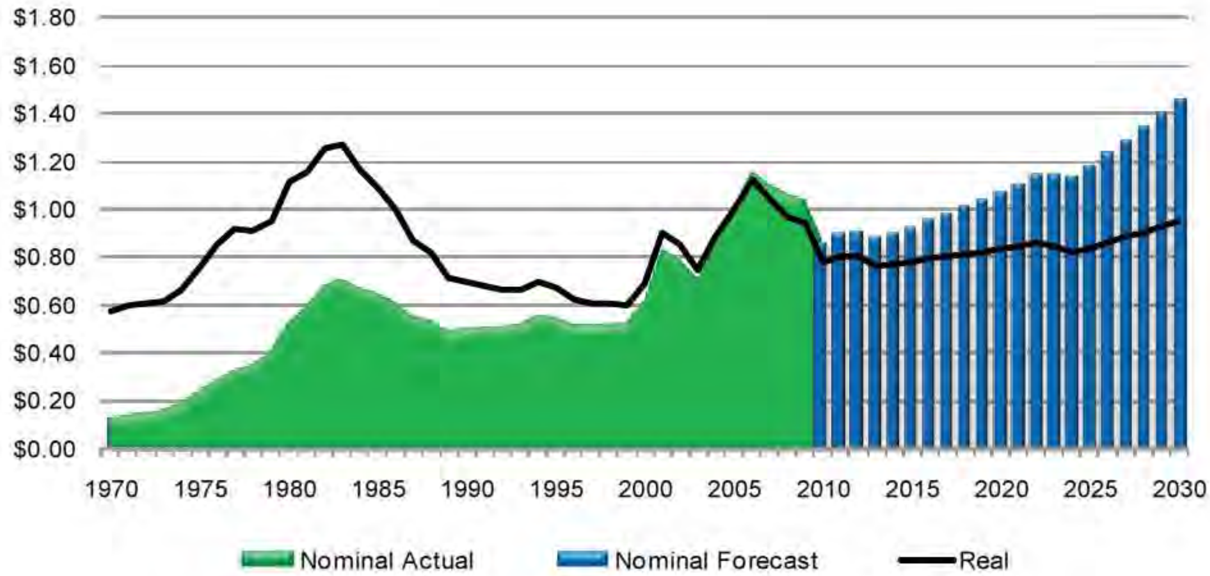

Figure 2. Forecasted residential natural gas prices
(dollars per therm)

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 2011 IRP price forecast, the long-term growth rates of electricity and natural gas prices are nearly identical.

Electric Vehicles

With the anticipated introduction of electric vehicles in December 2010 from General Motors and Nissan, Idaho Power includes a forecast of the potential load impact associated with customer needs for battery recharging. Without the benefit of actual consumer adoption data and clarity on charging infrastructure composition, the forecast methodology relies on previous modeling efforts from EPRI[1] and Oak Ridge National Laboratory[2] drawing on their forecasts of the electric-vehicle market share and charging usage and loads. The assumptions of these and other early forecasts were made without benefit of empirical vehicle performance attributes, such as vehicle battery capacity, pricing, actual consumer adoption behavior, and other salient marketing variables. Since these variables represent primary economic determinants of electric-vehicle adoption, the early forecasts are subject to potentially high degrees of revision. Other determinant variables, such as gasoline price, exhibit high degrees of volatility that add to the wide range of potential adoption outcomes.

The Oak Ridge study assumed a 25 percent electric-vehicle share of new vehicle registrations by 2020 and thereafter held constant. The EPRI study relied on year 2050 share scenarios that ranged from 20 percent to 80 percent. Their medium range forecast for 2020 was approximately 35 percent. After evaluating historical rates of adoption of new transportation technology, particularly those associated with fuel-efficient diesel engine adoption in Europe, the Idaho Power model was based on a

[1] Environmental Assessment of Plug-In Hybrid Electric Vehicles, July, 2007.

[2] Potential Impacts of Plug-in Hybrid Electric Vehicles on Regional Power Generation, January, 2008.

40-percent share by 2050 with annual adoption growth rate associated with diesel-technology adoption. The resulting Idaho Power forecast share of electric vehicles of new, light-duty vehicles registered in Idaho Power's service area is approximately 12 percent in 2020 and 26 percent in 2030. These rates were applied to a forecast of new, light-duty vehicle registrations for Idaho Power's service area using base-case assumptions from Moody's Analytics, Inc.

Idaho Power continues to capture consumer behavioral data and other salient market information associated with electric-vehicle adoption for the purposes of improving the forecasting model in future forecasts.

Figure 3 illustrates the increase in loads expected from the roll-out of electric vehicles over 2010–2030. The impact on the load forecast is assumed to be relatively small—about 9 aMW in 2020, reaching 43 aMW at the end of the forecast period in 2030. The load impacts were allocated to the residential and commercial sales forecasts using an 80/20 split, the residential sector representing the greatest impact.

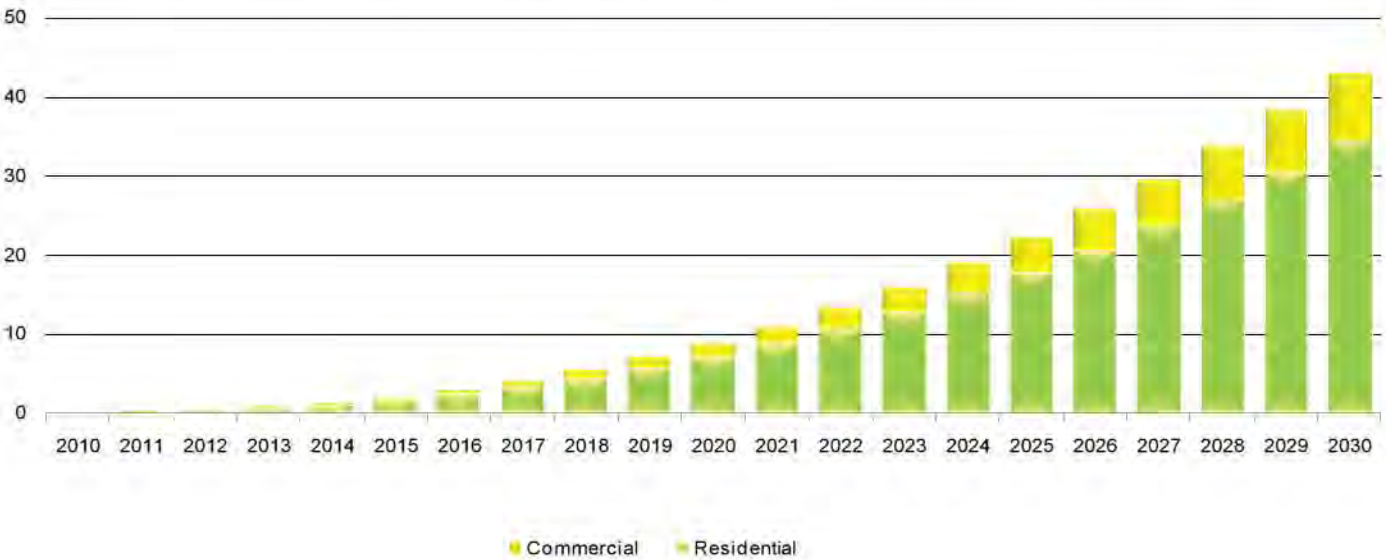

Figure 3. Electric vehicles
(aMW)

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 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 from Moody's Analytics, Inc., and the resulting derived economic forecast for Idaho Power's service area.

The expected-case load forecast assumes median temperatures and median precipitation, i.e., there is a 50 percent chance that 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, two alternative scenarios were considered that address load variability due to weather.

Maximum 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 load occurs when the lowest recorded levels of HDD are assumed in winter and the lowest recorded levels of CDD and GDD, combined with the highest level of precipitation, are assumed in summer.

For example, at the Boise Weather Service office, the median HDD in December over the 1980–2009 time period (the most recent 30 years) was 1,036. The 70th percentile HDD is 1,074 and would be exceeded in three-out-of-ten years. The 90th percentile HDD is 1,291 and would be exceeded in one-out-of-ten years. The 100th percentile HDD (the coldest December over the 30 years) is 1,619 and occurred in December 1985. This same concept was applied in each month throughout the year in only the weather-sensitive customer classes: residential, commercial, and irrigation.

In the 70th percentile residential and commercial load forecasts, temperatures in each month were assumed to be at the 70th percentile of HDD in wintertime and at the 70th percentile of CDD in summertime. In the 70th percentile irrigation load forecast, GDD were assumed to be at the 70th percentile and precipitation at the 30th percentile, reflecting drier-than-median weather. The 90th percentile load forecast was similarly constructed.

Idaho Power loads are highly dependent on weather, and these two scenarios allow 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 any given month. To assume that temperatures and precipitation would maintain a 70th percentile or 90th percentile level continuously, month after month throughout an entire year, would be much less probable. Monthly forecast numbers are evaluated for resource planning, and caution should be used in interpreting the meaning of the annual average load figures being reported and graphed for the 70th percentile or 90th percentile forecasts.

Table 2 summarizes the load scenarios prepared for the 2011 IRP. Three average load scenarios were prepared based on a statistical analysis of the historical monthly weather variables listed. The probability associated with each individual average load scenario is also indicated in the table. In addition, three peak-demand scenarios were prepared based on a statistical analysis of historical peak day average temperatures. The probability associated with each individual peak-demand scenario is also indicated in Table 2.

Table 2. 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 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. The expected-case load forecast reflects the consideration and integration of existing energy efficiency DSM program effects as a reduction to the average load forecast. In addition, retail electricity prices also serve to impact the growth in electricity sales long term.

Two additional load forecasts for the Idaho Power service area were prepared. The forecasts provide a range of possible load growths for the 2011–2030 planning period due to variable economic and demographic conditions. The high economic growth and low economic growth scenarios were prepared based on statistical analysis to empirically reflect uncertainty inherent in the load forecast. The average growth rates for the high- and low-growth scenarios were derived from the historical distribution of one-year growth rates over the past 25 years (1985–2009).

The estimated probabilities for the three different load scenarios are reported in Table 2. The probability estimates are calculated using the annual growth rates in weather-adjusted system sales (excluding Astaris) observed between 1985 and 2009. The standard deviation observed during the historical time period is used to estimate the dispersion around the expected-case scenario. The probability estimates assume that the expected forecast is the median growth path, i.e., there is a 50-percent probability that the actual growth rate will be less than the expected-case growth rate, and a 50-percent chance that the actual growth rate will be greater than the expected-case growth rate. In addition, the probability estimates assume that the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1985–2009). The high- and low-case load forecasts also reflect the consideration and integration of existing energy efficiency DSM program effects as a reduction to the average load forecasts.

Two types of probability estimates are reported in Table 3. The first probability, the probability of exceeding, shows the likelihood that 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 that the actual growth rate will exceed the growth rate projected in the high scenario, and conversely, there is a 10-percent chance that the actual growth rate would fall below that of the low scenario. In other words, over a 20-year time period, there is an 80-percent probability that the actual growth rate of system load will fall between the growth rates projected in the high and low scenarios. The second probability estimate, the probability of occurrence, indicates the likelihood that 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 that the actual growth rate will be closer to the high scenario than to any of the other forecast scenarios for the entire 20-year planning horizon. Probabilities for shorter, one-year, five-year, and 10-year time periods are also shown in Table 3.

Table 3. 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%

System load includes the sum of residential, commercial, industrial, irrigation, special contracts (including Astaris, historically), and Raft River. Idaho Power system load projections are reported in Table 4 and pictured in Figure 4. The expected-case system load forecast growth rate averages 1.4 percent per year over the 20 years of the planning period. The low scenario projects that system load will increase at an average rate of 1.0 percent per year throughout the forecast period. The high scenario projects load growth of 1.8 percent per year. Idaho Power has experienced both the high- and low-growth rates in the past. These scenario 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 4. System load growth
(aMW)

Growth	2011	2015	2020	2030	Annual Growth Rate 2011–2030
Low	1,793	1,894	1,970	2,158	1.0%
Expected	1,819	1,970	2,090	2,362	1.4%
High	1,878	2,094	2,271	2,642	1.8%

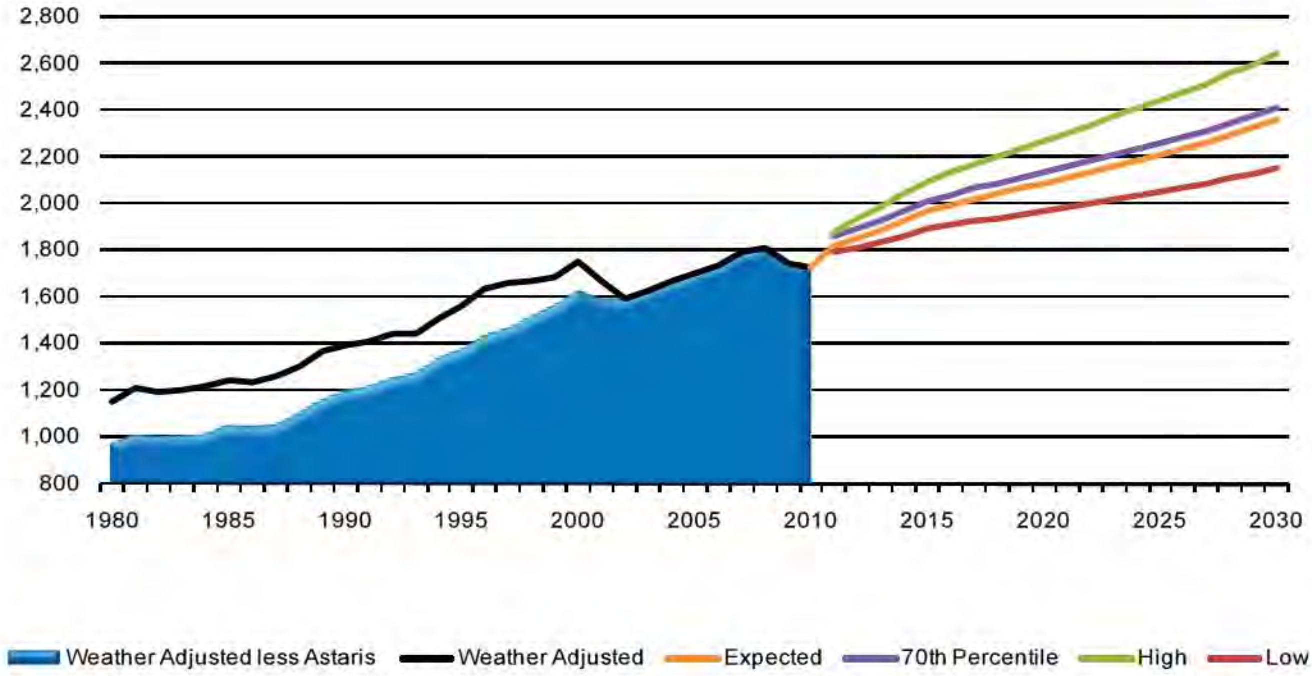

Figure 4. Forecasted system load
(aMW)

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RESIDENTIAL

The expected-case residential load is forecast to increase from 595 aMW in 2011 to 786 aMW in 2030, an average annual compound growth rate of 1.5 percent. In the 70th percentile scenario, residential load is forecast to increase from 611 aMW in 2011 to 810 aMW in 2030, matching the expected-case residential growth rate. The residential load forecasts are reported in Table 5 and shown graphically in Figure 5.

Table 5. Residential load growth
(aMW)

Growth	2011	2015	2020	2030	Annual Growth Rate 2011–2030
90th Percentile	646	681	744	860	1.5%
70th Percentile	611	644	702	810	1.5%
Expected Case	595	626	682	786	1.5%

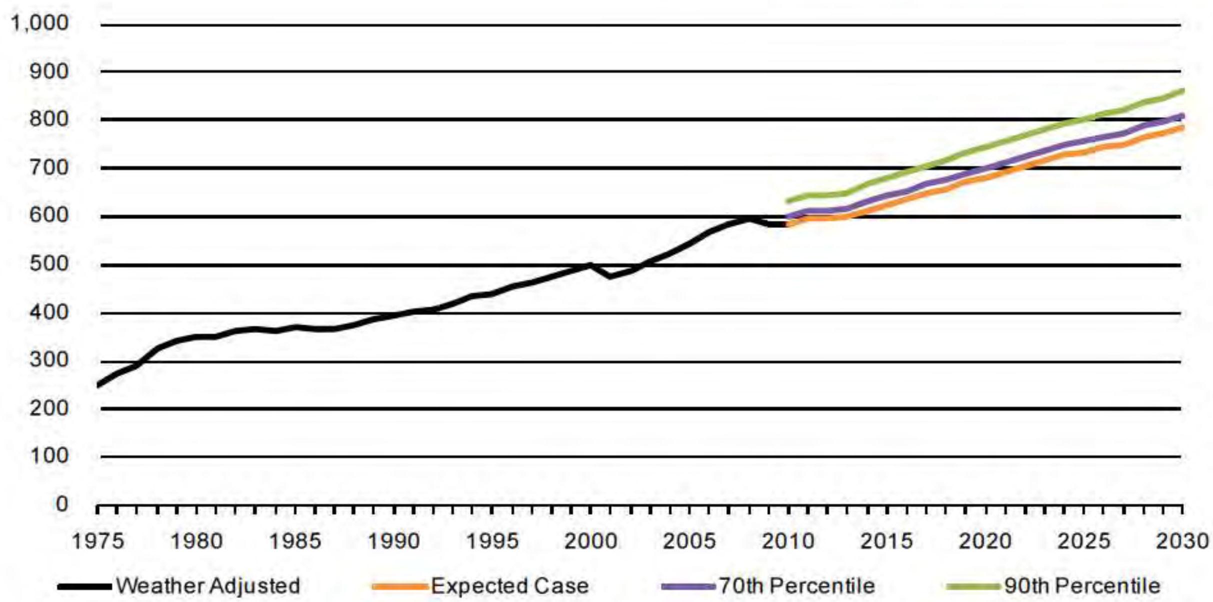

Figure 5. Forecasted residential load
(aMW)

Sales to residential customers made up 33 percent of Idaho Power's system sales in 1980 and 37 percent of system sales in 2010. The residential customer proportion of system sales is forecast to be approximately 36 percent in 2030. There were 408,754 residential customers as of December 2010. The number of residential customers is projected to increase to approximately 536,000 by December 2030. The relative customer proportions of Idaho Power's total electricity sales are shown in Figure 16.

The average sales per residential customer were nearly 13,000 kWh in 1975. Average sales increased to over 14,800 kWh per residential customer in 1979 before declining to 13,150 kWh in 2001. In 2002 and 2003, residential-use-per-customer dropped dramatically—over 500 kWh per customer from 2001—the result of two years of significantly higher electricity prices 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 and rise through 2007. However, the recession in 2008 and 2009 combined with conservation programs designed to reduce electricity use served to slow the growth in residential-use-per-customer. The average sales per residential customer are expected to slowly rise to approximately 12,900 kWh per year in 2030. Average annual sales per residential customer are shown in Figure 6.

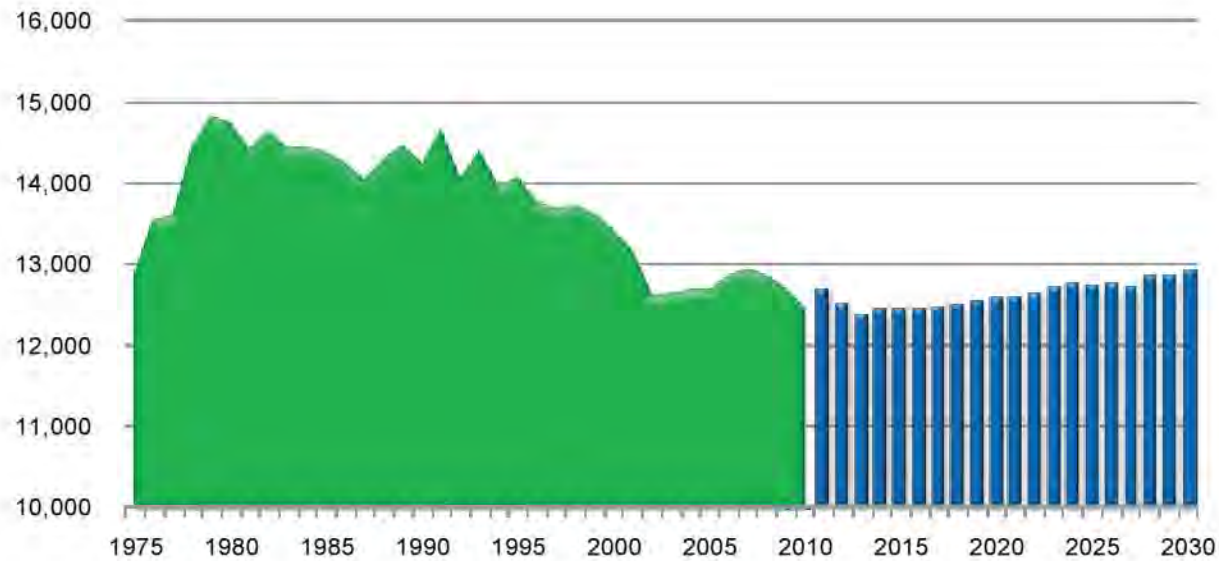

Figure 6. Forecasted residential-use-per-customer
(weather-adjusted kWh)

The residential-use-per-customer forecast is based on a forecast of the number of residential customers and an econometric analysis of residential-sector sales. The number of residential customers being added each year is a direct function of the number of new service-area households as derived from Moody's Analytics, Inc., July 2010 forecast of county housing stock and demographic data. The residential-customer forecast for 2011–2030 shows an average annual growth rate of 1.4 percent.

The residential sales forecast equation 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 as derived from Moody's Analytics, Inc., forecasts of county housing stock, the real price of electricity, and the real price of natural gas. The forecast of residential-use-per-customer is arrived at by dividing the residential sales forecast, which considers the impact of forecasted DSM, by the residential-customer forecast.

Commercial

The commercial category is primarily made up of Idaho Power's Small General Service and Large General Service customers. Other schedules considered part of the commercial category are Unmetered General Service, Street Lighting Service, Traffic Control Signal Lighting Service, and Dusk-to-Dawn Customer Lighting.

In the expected-case scenario, commercial load is projected to increase from 439 aMW in 2011 to 561 aMW in 2030. The average annual compound-growth rate of commercial load is 1.3 percent during the forecast period. As summarized in Table 6, the commercial load in the 70th percentile scenario is projected to increase from 443 aMW in 2011 to 568 aMW in 2030. The commercial load forecasts are illustrated in Figure 7.

Table 6. Commercial load growth
(aMW)

Growth	2011	2015	2020	2030	Annual Growth Rate 2011–2030
90th Percentile	453	479	504	583	1.3%
70th Percentile	443	468	492	568	1.3%
Expected Case	439	463	486	561	1.3%

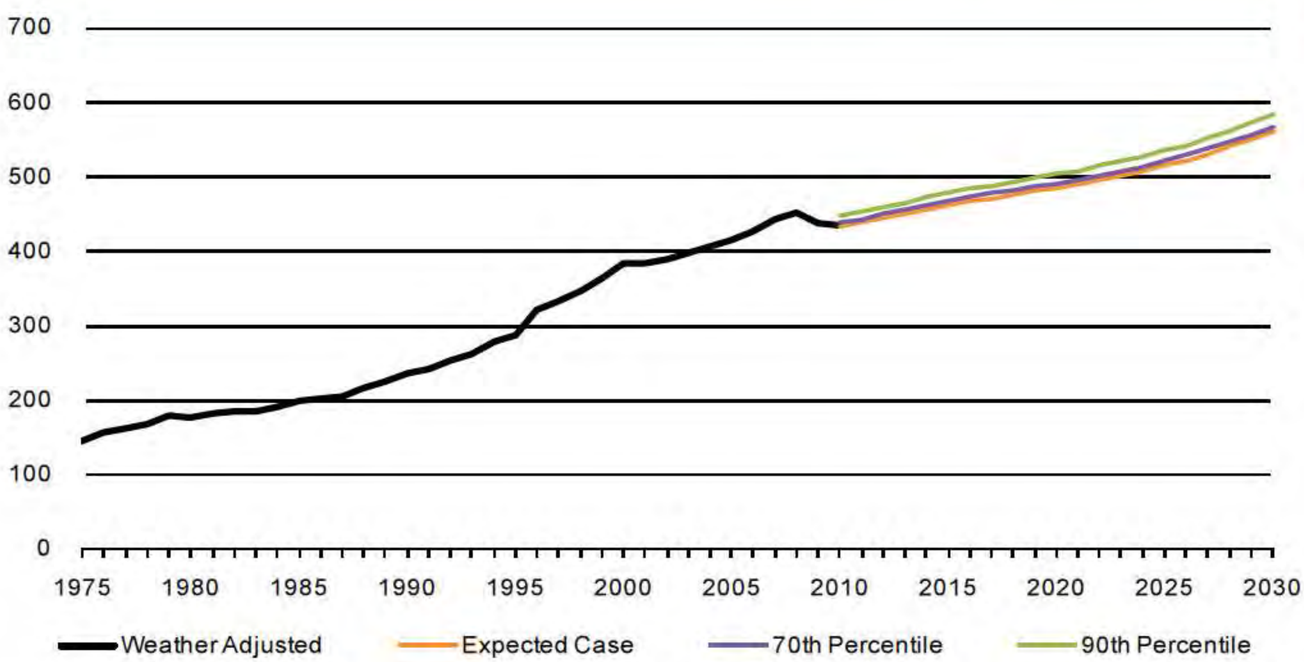

Figure 7. Forecasted commercial load
(aMW)

As of December 2010, Idaho Power had 64,647 commercial customers. The number of commercial customers is expected to increase at an average annual growth rate of 2 percent, reaching 94,600 customers by 2030. Commercial customers consumed nearly 17 percent of Idaho Power system sales in 1980 and nearly 28 percent of system sales in 2010. The commercial customer proportion of system sales is projected to decline to 26 percent of system sales by 2030. The relative customer proportions of Idaho Power's total electricity sales are shown in Figure 16.

The average consumption per commercial customer increased to a record 67,500 kWh in 2001. However, two years of significantly higher electricity prices combined with a weak national and service-area economy caused a setback in the growth of commercial-use-per-customer beginning in 2002. The reduction in electricity prices in June 2003 and a recovery in the service-area economy slowed the rate of decline in commercial-use-per-customer through 2007. However, a severe recession in 2008 and 2009 caused commercial-use-per-customer to drop considerably. After flattening out over the time period 2010–2011, commercial-use-per-customer is projected to continue its downward trend. The primary reasons for the decline are higher retail electricity prices due to generating plant additions and DSM program impacts on energy sales. The average consumption per commercial customer is expected to decrease to approximately 52,400 kWh per customer in 2030. Average annual use per commercial customer is shown in Figure 8.

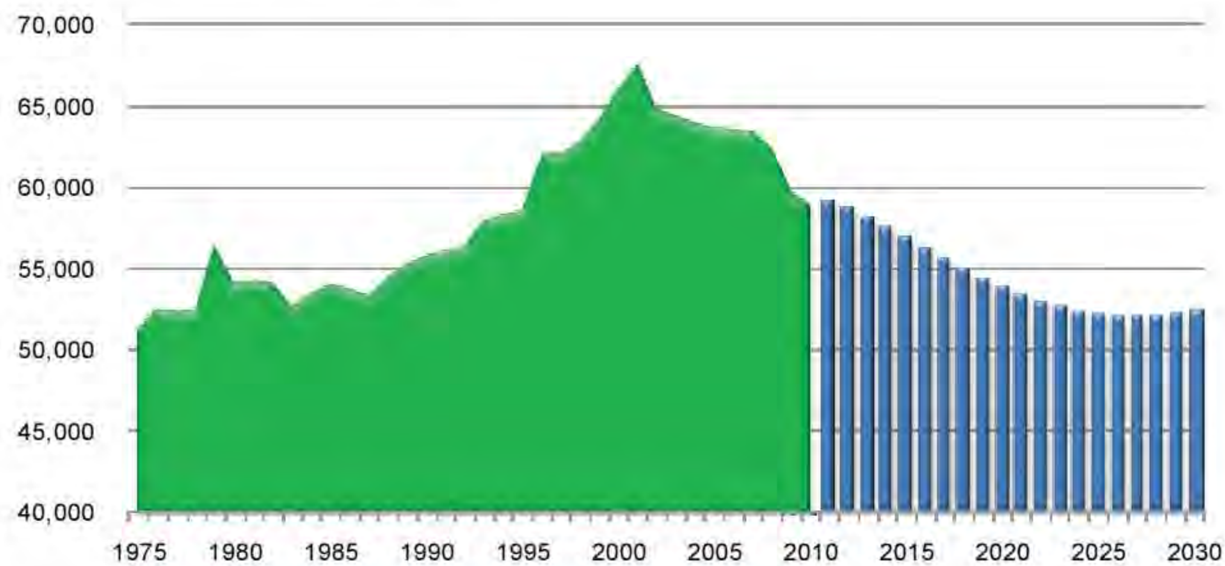

Figure 8. Forecasted commercial-use-per-customer
(weather-adjusted kWh)

The commercial-use-per-customer forecast is based on a forecast of the number of commercial customers and an econometric analysis of commercial sector sales. The number of commercial customers being added each year is a direct function of the number of new residential customers being added. Additionally, the number of residential customers being added is a direct function of the number of new service-area households as derived from Moody's Analytics, Inc., July 2010 economic forecast of county housing stock and demographic data. The commercial-customer forecast for 2011–2030 shows an average annual growth rate of 2 percent.

The commercial-sales forecast equation considers several factors affecting electricity sales to the commercial sector. Commercial sales are a function of HDD (wintertime), CDD (summertime), the number of service area households and service area employment as derived from Moody's Analytics, Inc., forecasts, and the real price of electricity. The commercial-use-per-customer forecast is arrived at by dividing the commercial sales forecast, which considers the impacts of forecasted DSM, by the commercial-customer forecast.

IRRIGATION

The irrigation category is made up 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.

Throughout the forecasted period, the expected-case irrigation load is forecast to slowly rise from 197 aMW in 2011 to 207 aMW in 2030, an average annual compound growth rate of 0.3 percent. The expected-case, 70th percentile, and 90th percentile scenarios forecast slow growth in irrigation load over the 2011–2030 time period. In the 70th percentile scenario, irrigation load is projected to be 213 aMW in 2011 and 223 aMW in 2030. The individual irrigation load forecasts are reported in Table 7 and shown in Figure 9. The figure illustrates the poorer economic conditions and the dramatic reduction in land being put into production that was experienced by the agricultural economy in the mid-1980s.

Table 7. Irrigation load growth
(aMW)

Growth	2011	2015	2020	2030	Annual Growth Rate 2011–2030
90th Percentile	232	234	237	242	0.2%
70th Percentile	213	215	217	223	0.2%
Expected Case	197	199	202	207	0.3%

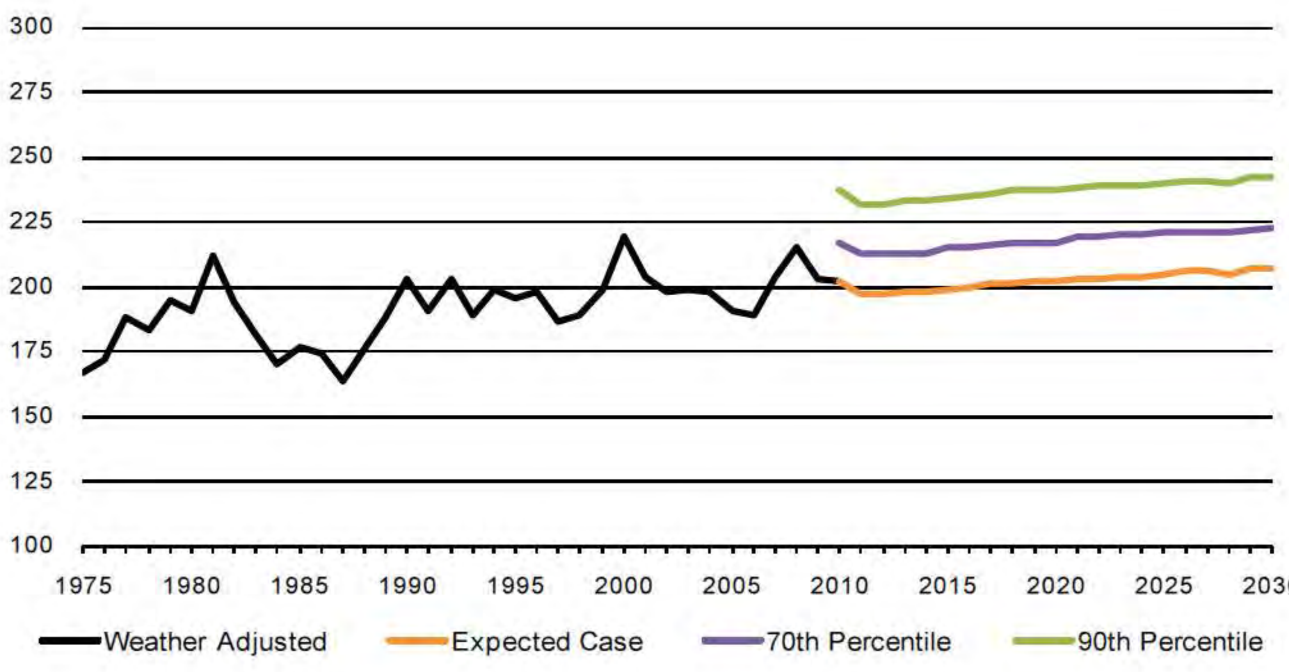

Figure 9. Forecasted irrigation load
(aMW)

It is important to understand the annual average-load figures reported in Table 7 and graphed in Figure 9 are calculated using the 8,760 hours of 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 exceed 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 30 percent of the energy consumed during the July calendar-month for general business sales. Note that it is the monthly forecast load figures that are being evaluated for resource planning purposes, not the annual average loads.

The 2011 irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature, precipitation, spring rainfall, *Moody's Gross Produce: Farms, for Idaho*, and the real price of electricity. Considerations were made for the unusually low electricity consumption in the 2001 crop year due to the voluntary load-reduction program.

In early 2001, wholesale electricity prices reached unprecedented levels; Idaho Power, in an attempt to minimize reliance on the market, developed a voluntary load-reduction program that paid irrigators to reduce consumption of electricity in 2001. The voluntary load-reduction program was effective and resulted in a 30 percent, or approximately 500,000 megawatt-hour (MWh) reduction in 2001 irrigation sales. The 2001 irrigation sales and corresponding loads have been adjusted upward by 499,319 MWh to reflect a more normal 2001 irrigation season.

Actual irrigation electricity sales have grown from the 1970 level of 816,000 MWh to a peak amount of 1,990,000 MWh in 2000. Idaho Power projects no growth in irrigated acres in the service area and limited growth in sprinkler irrigation or conversion to sprinkler irrigation.

Irrigation sales represented about 18 percent of weather-normalized Idaho Power system sales in 1980. Irrigation sales reached a maximum proportion of 20 percent of Idaho Power system sales in 1977. In 2010, the irrigation proportion of system sales was 13 percent due to the much higher relative growth in other customer classes. By 2030, irrigation customers are projected to consume less than 10 percent of Idaho Power system sales. The irrigation customer load proportion is shown in Figure 16.

In 1980, Idaho Power had about 10,850 active irrigation accounts. By 2010, the number of active irrigation accounts had increased to 17,846 and is projected to be about 23,500 irrigation accounts at the end of the planning period in 2030.

Since 1988, Idaho Power has experienced some growth in the number of irrigation customers, but very little, if any, 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. However, the conversion rate is low, and the kWh use-per-customer for these customers is substantially less than the average existing Idaho Power irrigation customer. This is due to the fact that water for furrow irrigation is gravity-drawn from canals and not pumped from deep, groundwater wells. In 2007 and 2008, irrigation sales (weather-adjusted) increased by 8 percent and 6 percent, respectively, over each prior year. The increase can be explained, in part, by the gradual increase in the planting of more water-intensive crops, such as alfalfa and corn, to meet the higher demand for feed associated with the growing dairy industry in Idaho. Also, 2008 saw unprecedented crop prices for almost all crops, causing customers to irrigate all of the acreage that was available in 2008.

Bell Rapids, a large, high-lift cooperative irrigation company that irrigated about 25,000 acres from 1970 to 2004, was Idaho Power's largest irrigation customer. The Bell Rapids combined accounts included more than 40 individual irrigation service points that accounted for approximately 3 to 4 percent of Idaho Power's annual irrigation sales. In early 2005, the State of Idaho purchased the water rights from Bell Rapids, which resulted in the loss of Bell Rapids as an irrigation customer. Prior to 2005, Bell Rapids consumed, on average, 55,000 MWh each year.

In the future, 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 made up of Idaho Power's Large Power Service (Schedule 19) customers with monthly metered demands between 1,000 kW and 20,000 kW. In 1975, Idaho Power had about 70 industrial customers, which represented about 10 percent of Idaho Power's system sales. By December 2010, the number of industrial customers had risen to 121, representing approximately 16 percent of system sales. Special contracts are addressed in the Additional Firm Load section of this document.

In the expected-case forecast, industrial load grows from 262 aMW in 2011 to 359 aMW in 2030, an average annual growth rate of 1.7 percent (Table 8). As a general rule, industrial loads are not weather sensitive, and the forecasts in the 70th and 90th percentile scenarios are identical to the expected-case industrial load scenario. The industrial load forecast is pictured in Figure 10.

Table 8. Industrial load growth
(aMW)

Growth	2011	2015	2020	2030	Annual Growth Rate 2011–2030
Expected Case	262	283	302	359	1.7%

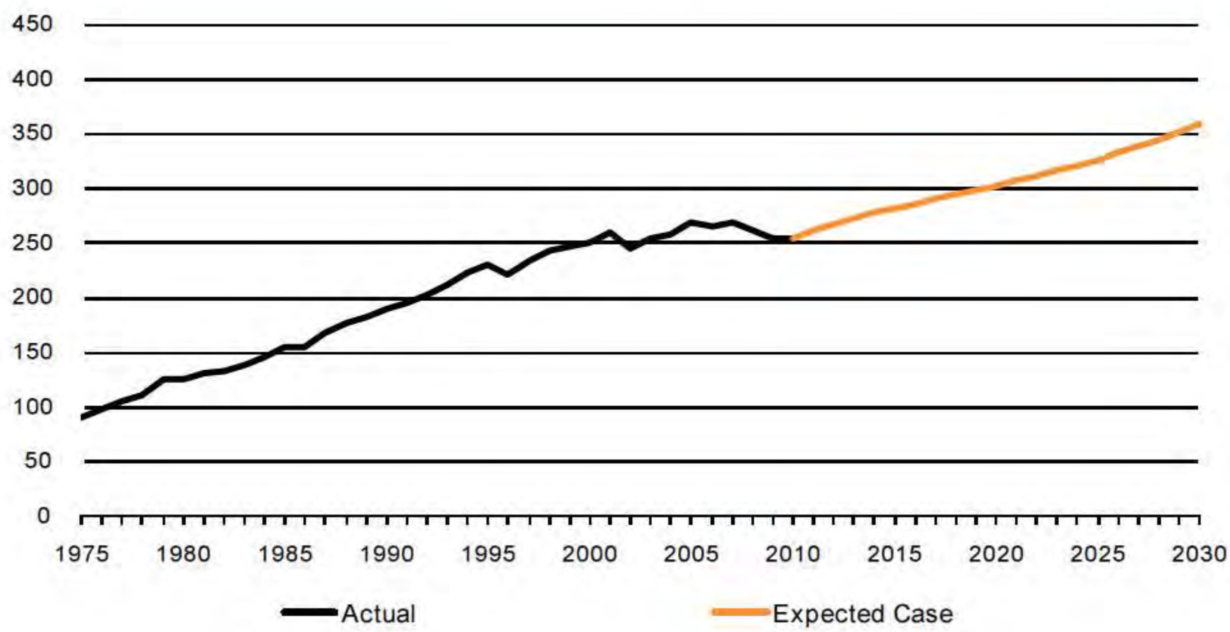

Figure 10. Forecasted industrial load
(aMW)

The industrial energy forecast is based on the most recent (July 2010) national, state, MSA, and county economic forecasts from Moody's Analytics, Inc., and the resulting derived economic forecast for Idaho Power's service area.

Since rate tariff definitions do not correspond with economic activity types, Idaho Power's Schedule 19 customers were categorized, and their historical electricity sales were summarized by economic activity. This is also true for the large commercial loads, so Schedule 9 Primary and Transmission customers' energy sales were also included for forecasting purposes and later recombined with the commercial sector sales forecast. The appropriate employment series (or population time series) were matched to each economic sector or industry group. Regression models were developed for 17 industry groups to determine the relationship between historical electricity sales and historical employment, population, and/or other relevant explanatory variables. The estimated coefficients from the industry group regression models were then applied to the appropriate employment, population, and other relevant drivers, which resulted in the escalation of electricity sales to the various industry groups over time.

Figure 11 illustrates the 2010 industrial electricity consumption by industry group. By far the largest share of electricity was consumed by the Food and Kindred Products sector (46 percent); followed by Electronic/Electrical Equipment and Industrial/Commercial Machinery (7 percent); Educational Services, Wholesale and Retail Trade, and Health Services (each representing 6 percent); and Other Manufacturing (5 percent). As Figure 11 shows, several other industry groups make up the remaining share of the 2010 industrial electricity consumption.

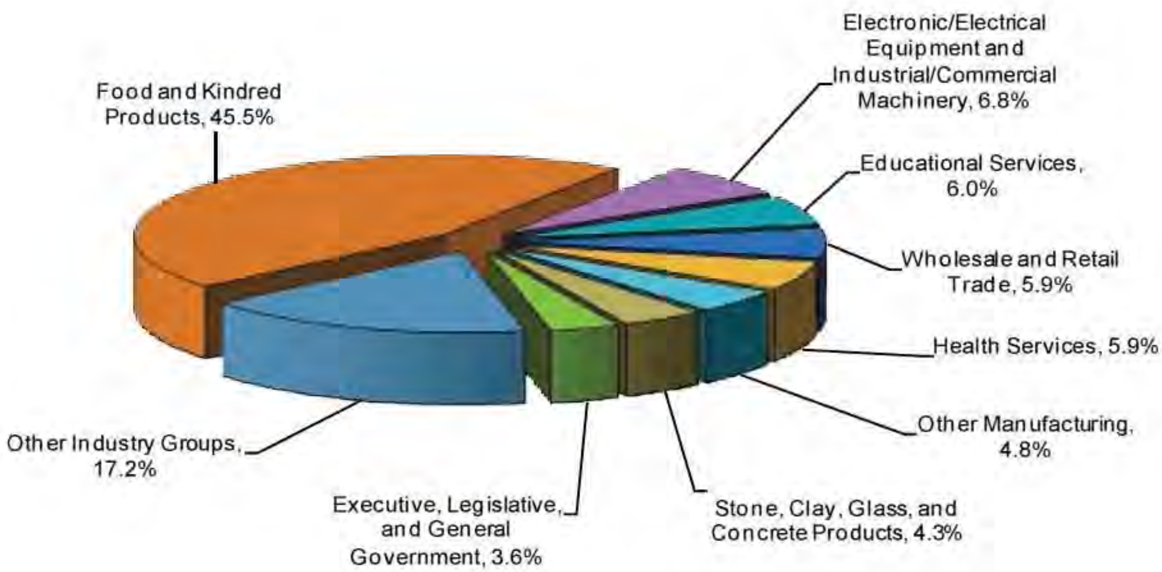

Figure 11. Industrial electricity consumption by industry group
(based on 2010 figures)

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 of these individual large-power customers. The contract and tariff schedule are then approved by the appropriate commission. A special contract allows for customer-specific, cost-of-service analysis and consideration of unique operating characteristics to be accounted for in the agreement. A special contract also allows Idaho Power to provide requested service consistent with system capability and reliability. Idaho Power currently has four special contract customers recognized as firm load customers. These special contract customers are Micron Technology, Simplot Fertilizer, INL, and Hoku Materials. In addition, the company has a term sales contract with Raft River. Raft River is not required to meet the 20-MW electric service minimum.

It is difficult to predict when a new special contract customer will begin taking service from Idaho Power. However, because of the magnitude of their load and subsequent impact on system resources, it is important to anticipate such load if a customer of that size is considered eminent. In this year's forecast, the company has included the anticipated load of an additional special contract customer referred to as "Special" in the additional firm load category, even though a long-term special contract had not yet been fully executed. At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined that the real possibility of the new large load was significant enough that it would be imprudent of the company to ignore the possible impact. The anticipated load of the new "Special" contract has been included in this forecast based on discussions with the interested parties. The existing special contract customers and the new "Special" contract together make up the additional firm load category.

In the expected-case forecast, additional firm load is expected to increase from 165 aMW in 2011 to 243 aMW in 2030, an average growth rate of 2 percent per year over the planning period (Table 9). 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 12.

Table 9. Additional firm load growth
(aMW)

Growth	2011	2015	2020	2030	Annual Growth Rate 2011–2030
Expected Case	165	229	236	243	2%

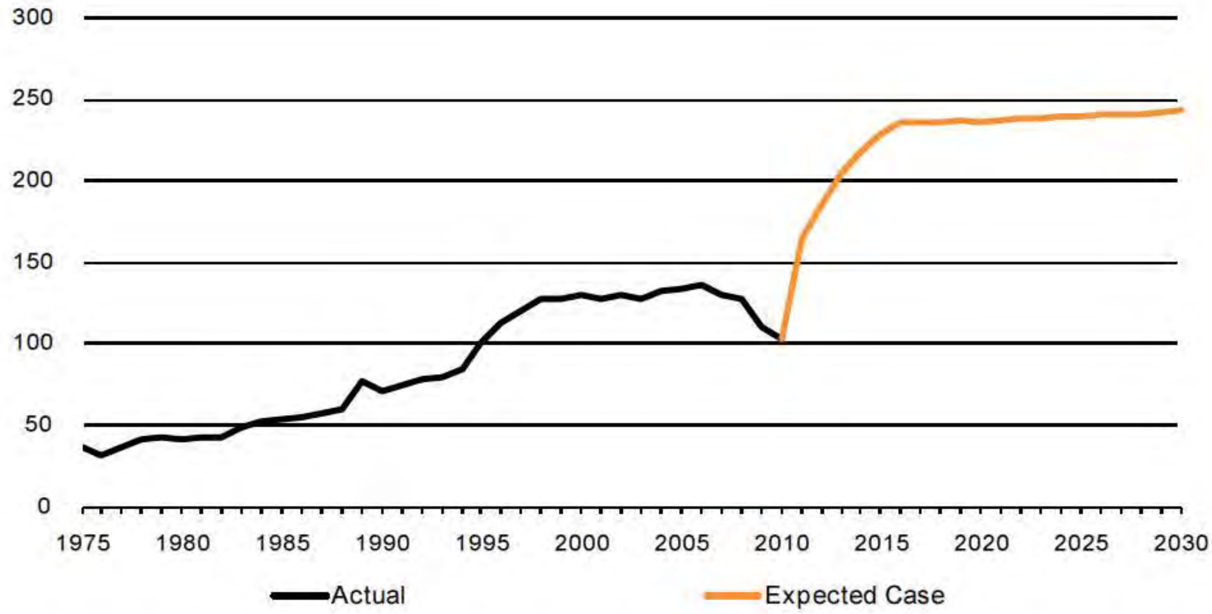

Figure 12. Forecasted additional firm load
(aMW)

Micron Technology

Micron Technology is currently Idaho Power's largest individual customer and employs approximately 5,000 workers in the Boise MSA. Electricity sales to Micron Technology moved considerably downward in 2009 and 2010 as Micron phased out its 200-millimeter (mm) dynamic random access memory (DRAM) operations at its Boise facility. The company continues to operate its 300-mm research and development fabrication facility in Boise and perform a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, corporate, and general services. Once establishing a new floor for energy consumption at the facility at about a quarter less energy use than in recent years, Micron Technology's electricity use is expected to increase based on the market demand for their products.

Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western United States. The future electricity usage at the plant is expected to grow at a slow pace throughout the planning period (2011–2030). The primary driver of long-term electricity sales growth at Simplot Fertilizer is Moody's Analytics, Inc., forecast of gross product in the pesticide, fertilizer, and other agricultural chemical manufacturing for the Pocatello MSA.

Idaho National Laboratory

The US Department of Energy (DOE) provided an energy-consumption and peak-demand forecast through 2030 for the INL. The forecast calls for loads to increase considerably through 2014, remain flat for six years, and then slowly decline throughout the remainder of the forecast period. As of October 1994, the INL nuclear reactor no longer generates electricity, consequently, the amount of electricity provided by Idaho Power increased considerably.

Hoku Materials

The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special contract customer, Hoku Materials, located in Pocatello, Idaho. At the time this forecast was completed (August 2010), Hoku Materials was planning to begin operation in January 2011 and reach full capacity by April 2011. The current sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses), once continuous operation is reached in 2013.

"Special" Contract

In this year's forecast, an additional customer referred to in this document as "Special" was included in the additional firm load category, even though a long-term contract had not yet been fully executed. At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined that the real possibility of the new large load was significant enough that it would be imprudent of the company to ignore the possible impact. The anticipated load of the new "Special" contract has been included in this forecast based on discussions with the interested parties. The existing special contracts and the new "Special" contract together make up the additional firm load category.

Raft River Rural Electric Cooperative

A term sales contract with Raft River was established as a full-requirements contract after being approved by the Federal Energy Regulatory Commission (FERC) and the Public Utility Commission of Nevada. Raft River is the electric distribution utility serving Idaho Power's former customers in Nevada. In April 2001, Idaho Power sold the transmission facilities and rights-of-way that serve about 1,250 customers in northern Nevada and 90 customers in southern Owyhee County to Raft River. Raft River is located entirely within Idaho Power's load control area.

The contract with Raft River expired on September 30, 2010. However, Raft River renewed the agreement for an additional one-year term, which would extend service until September 30, 2011. The load forecasts in the 2011 IRP assume that Idaho Power will continue to provide service to the Raft River area through September 30, 2011.

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Company System Peak

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

The all-time system summer peak demand was 3,214 MW, recorded on Monday, June 30, 2008, at 3:00 p.m. The previous year's summer peak demand was 3,193 MW and occurred on Friday, July 13, 2007, at 4:00 p.m. The summer system peak load growth accelerated over the 10 years ending in 2008 as a record number of residential and commercial customers were added to the system and air conditioning became standard in nearly all new residential homes and new commercial buildings.

In the 90th percentile forecast, total system summer peak load is expected to increase from 3,494 MW in 2011 to 4,870 MW in the year 2030, an average growth rate of 1.8 percent per year over the planning period (Table 10). In the 95th percentile forecast, total system summer peak load is expected to increase from 3,515 MW in 2010 to 4,901 MW in the year 2030. The three scenarios of projected system summer peak load are illustrated in Figure 13. The 2001 summer peak was dampened by the nearly 30 percent curtailment in irrigation load due to the 2001 voluntary load-reduction program.

Table 10. System summer peak load growth
(MW)

Growth	2011	2015	2020	2030	Annual Growth Rate 2011–2030
95th Percentile	3,515	3,854	4,190	4,901	1.8%
90th Percentile	3,494	3,831	4,164	4,870	1.8%
50th Percentile	3,334	3,657	3,973	4,643	1.8%

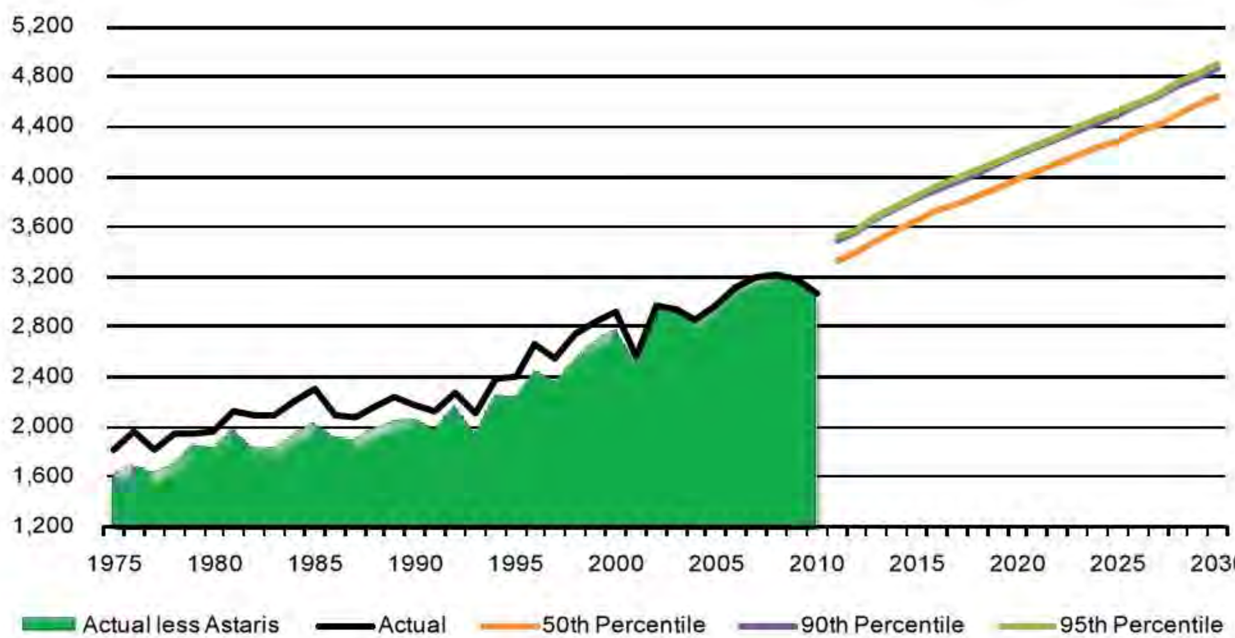

Figure 13. Forecasted system summer peak
(MW)

The all-time system winter peak demand was 2,528 MW, reached on Thursday, December 10, 2009, at 8:00 a.m. As shown in Figure 14, historical system winter peak load is much more variable than summer system peak load. This is because the variability of peak day temperatures in winter months is far greater than the variability of peak day temperatures in summer months. The wider spread of the winter peak forecast lines in Figure 14 illustrates the higher variability associated with winter peak-day temperatures.

In the 90th percentile forecast, total system winter peak load is expected to increase from 2,693 MW in 2011 to 3,336 MW in 2030, an average growth rate of 1.1 percent per year over the planning period (Table 11). In the 95th percentile forecast, total system winter peak load is expected to increase from 2,815 MW in 2011 to 3,509 MW in 2030, an average growth rate of 1.2 percent per year over the planning period (Table 11). The three scenarios of projected system winter peak load are illustrated in Figure 14.

Table 11. System winter peak load growth
(MW)

Growth	2011	2015	2020	2030	Annual Growth Rate 2011–2030
95th Percentile	2,815	2,948	3,121	3,509	1.2%
90th Percentile	2,693	2,815	2,976	3,336	1.1%
50th Percentile	2,384	2,478	2,604	2,896	1.0%

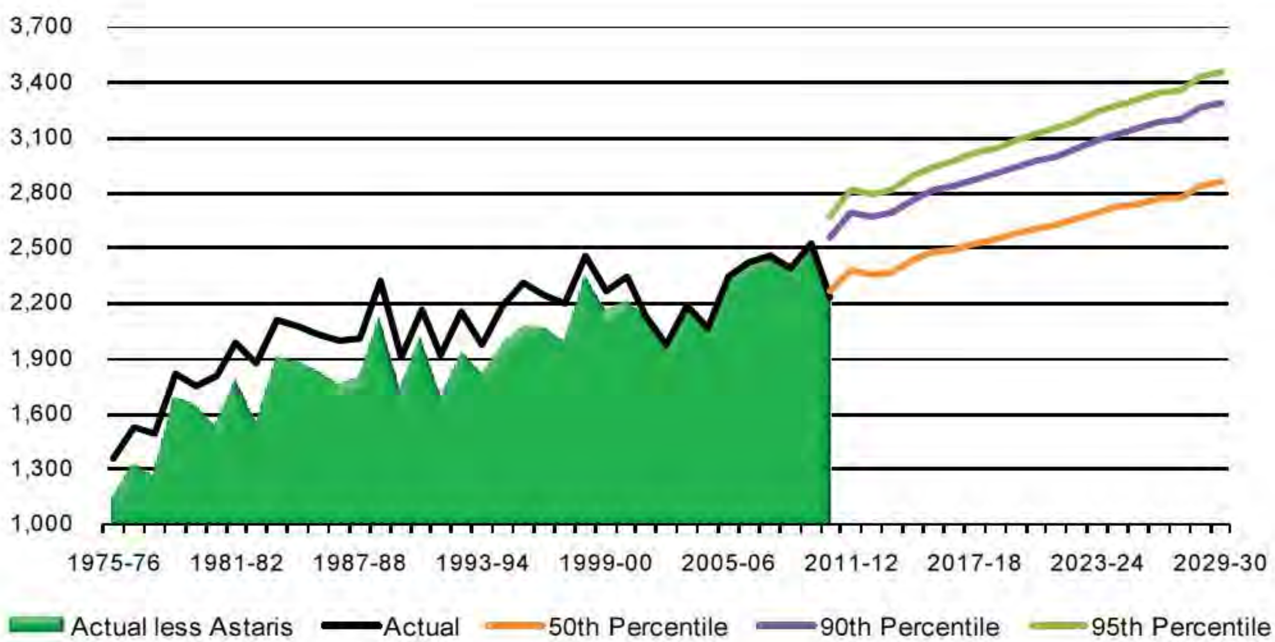

Figure 14. Forecasted system winter peak
(MW)

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 Raft River. System load excludes all long-term, firm, off-system contracts.

The expected-case system load forecast is based on the most recent Moody's Analytics, Inc., economic forecast for the nation and the service area and represents Idaho Power's most probable load growth during the planning period. The expected-case forecast system load growth rate averages 1.4 percent per year over the 2011–2030 time period. Company system load projections are reported in Table 12 and shown in Figure 15.

In the expected-case forecast, company system load is expected to increase from 1,819 aMW in 2011 to 2,362 aMW in 2030. In the 70^{th} percentile forecast, company system load is expected to increase from 1,860 aMW in 2011 to 2,414 aMW by 2030, an average growth rate of 1.4 percent per year over the planning period (Table 12).

Table 12. System load growth
(aMW)

Growth	2011	2015	2020	2030	Annual Growth Rate 2011–2030
90^{th} Percentile	1,931	2,088	2,218	2,508	1.4%
70^{th} Percentile	1,860	2,013	2,136	2,414	1.4%
Expected Case	1,819	1,970	2,090	2,362	1.4%

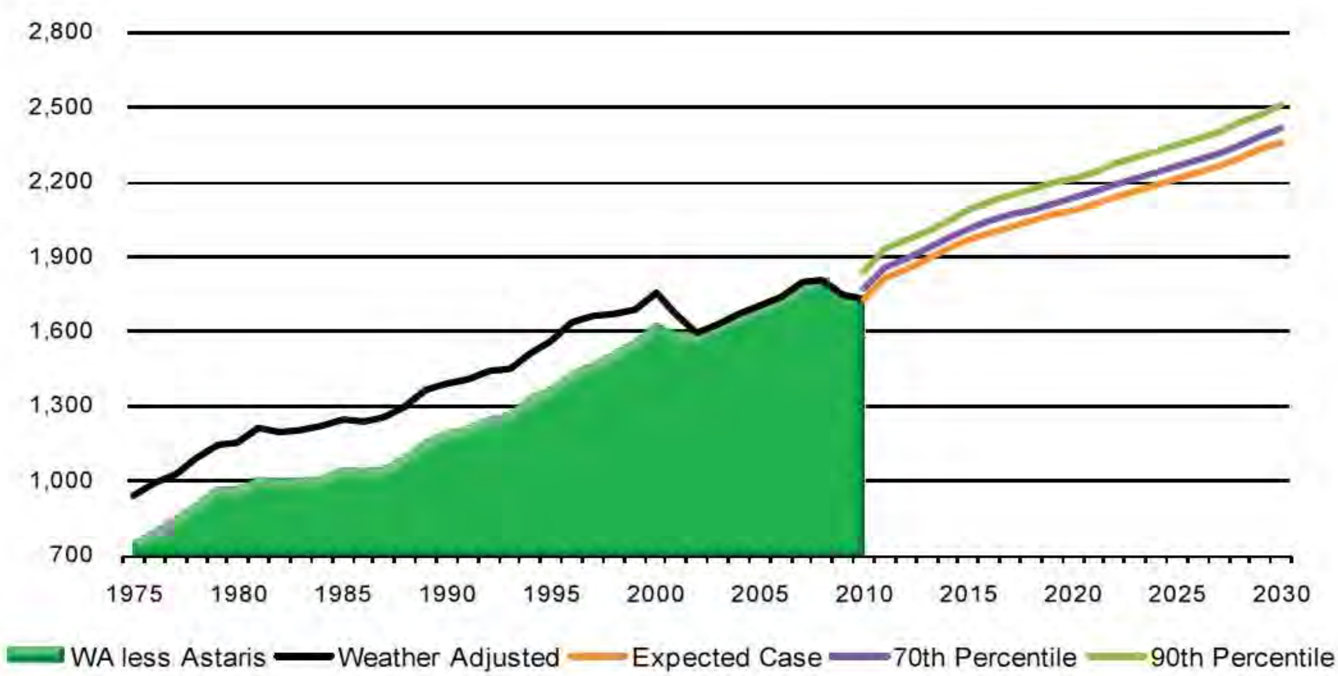

Figure 15. Forecasted system load
(aMW)

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 has been Idaho Power's largest individual customer and, in some past years, averaged nearly 200 aMW each month. In April 2002, the special contract between Astaris and Idaho Power was terminated. Without the dampening effects of Astaris on historical system load growth, the system load excluding Astaris more accurately portrays the underlying general business growth trend within the service area.

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 into additional long-term contracts to supply firm energy to off-system customers if surplus energy is available.

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Total Company Load

Accompanied by an outlook of moderate economic growth for Idaho Power's service area throughout the forecast period, *Appendix A–Sales and Load Forecast* projects continued growth in Idaho Power's total load. 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 total company electricity sales by year is shown in Figure 16. Residential sales are forecast to be over 32 percent higher in 2030, gaining nearly 1.7 million MWh over 2011. Commercial sales are expected to be nearly 28 percent higher or nearly 1.1 million MWh above 2011 followed by industrial (37 percent higher or nearly 0.8 million additional MWh) and irrigation (only 5 percent higher in 2030 than 2011). Electricity sales to Astaris ended in April 2002.

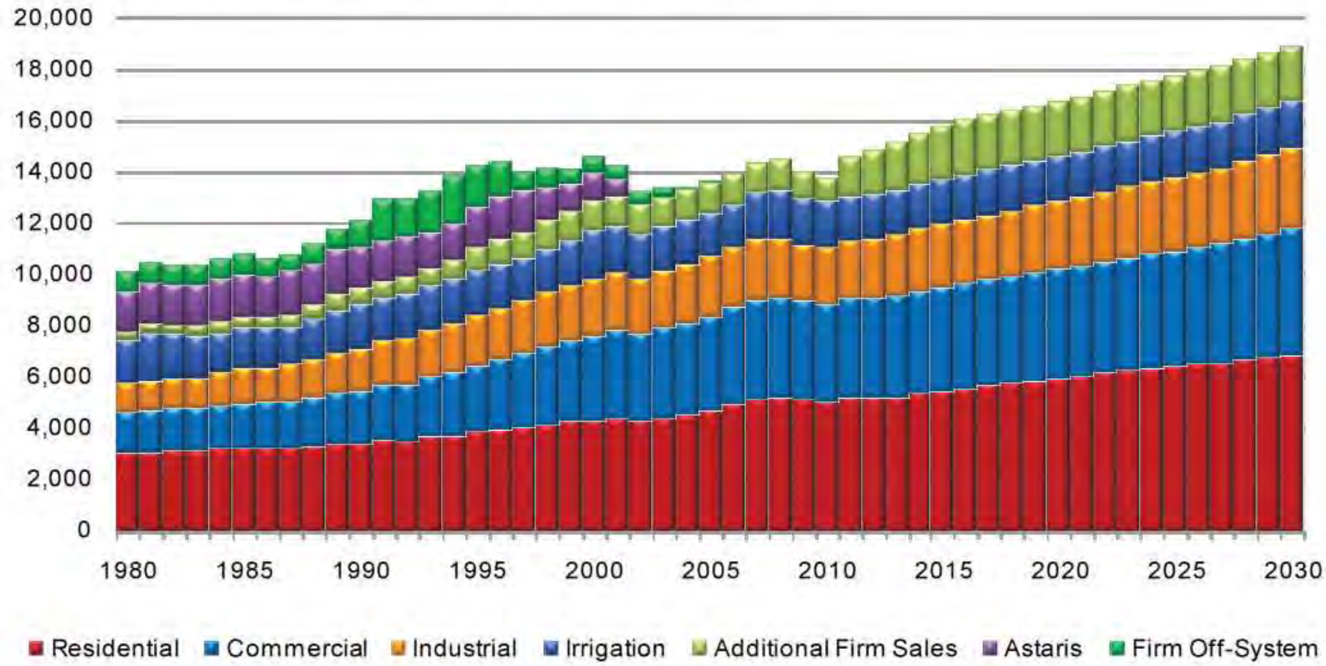

Figure 16. Composition of total company electricity sales
(thousands of MWh)

The additional firm load category (which represents sales to Micron Technology, Simplot Fertilizer, INL, Hoku Materials, Idaho Power's newest "Special" contract customer, and Raft River) is forecast to grow by 47 percent over the 2011–2030 time period, largely due to the addition of Hoku Materials and Idaho Power's newest "Special" contract customer as special contract customers.

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DEMAND-SIDE MANAGEMENT

DSM consists of energy efficiency programs that reduce customer energy use year-round and demand response programs that are targeted at reducing load during specific periods of high demand. The impact of energy efficiency programs are considered in the 2011 IRP *Appendix A–Sales and Load Forecast*; however, demand response programs are accounted for in the 2011 IRP load and resource balance and not in the load forecast. The sales and load forecast, adjusted for existing and committed energy efficiency programs, serves as the basis for establishing the baseline forecast for surpluses and deficits which were used to develop portfolios for the 2011 IRP.

Energy Efficiency Programs

The 2011 IRP *Appendix A–Sales and Load Forecast* follows the methodology established in an Itron white paper[3], "Incorporating DSM into the Load Forecast". The authors discussed methods for adjusting load forecasts to account for DSM programs. According to Itron, there are several potential econometric frameworks that can be applied to account for DSM in the forecast period. The methods are designed to adjust the load forecast by accounting for the amount and continuing momentum of the historic DSM contained in the load forecast model.

The "DSM trend" method was chosen as the preferred method to incorporate DSM into the load forecasts for the commercial, industrial, and irrigation sectors. The alternative methods make explicit efforts to adjust DSM out of the history and out of the forecast. The DSM trend takes a different approach by recognizing that historical DSM and DSM trends are embedded in the actual sales data. Forecasting models built on these data implicitly assume that the levels and trends for DSM savings in the history continue into the forecast at approximately the same rate. As a result, the forecast needs to be adjusted only if DSM impacts are expected to be greater or less than the historical trends.

In the final step of the DSM trend method, the forecast is adjusted if the cumulative impacts of past and future programs are expected to accelerate or decelerate relative to the DSM trend line. In this method, the forecast is adjusted up or down by the difference between the DSM trend line and the cumulative impact of past and future programs.

If the total cumulative impact of past and future programs is expected to fall short of the historical trend, then the energy forecast should be adjusted upward by the amount of the deceleration below the DSM trend line.

In another improvement to this year's forecast, Idaho Power used Itron's residential SAE model to prepare the long-term residential sales forecast. Recently, many utilities have adopted Itron's SAE modeling approach to include greater end-use information into the forecast process. When applying the SAE framework, DSM activity is naturally incorporated in the efficiency assumptions and the calibration to historic sales data. Efficiency assumptions incorporate national-level DSM impacts. Calibration incorporates specific utility DSM impacts. Therefore, additional adjustments to the residential energy forecast for existing DSM programs were not made.

When using an econometric or SAE model, historical DSM investments influence the historical sales data, the forecast model parameters, and the resulting sales projections. As DSM investment increases,

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[3] 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).

forecasters need to adjust their sales forecasts to account for this acceleration relative to the historic DSM implicitly included in an unadjusted forecast.

The forecast resulting from the adjusted history is designed to reflect sales without the impact of energy efficiency programs. The results from the regression models are subsequently adjusted downward to account for future energy efficiency program performance.

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

Because the sales and load forecast is prepared before new energy efficiency programs are determined, new energy efficiency programs are not included in the forecast. The impact of the new programs is accounted for in the IRP load and resource balance prior to determining the need for additional supply-side resources. The forecast performance of both existing and new energy efficiency and demand response programs is shown in the load and resource balance in *Appendix C–Technical Appendix*. In the next planning cycle, the impact of new committed programs will be considered when updating the individual class-level sales forecasts.

Demand Response Programs

Prior to the 2009 IRP, demand response program performance was accounted for in the sales and load forecast. Beginning with the 2009 IRP, demand response programs are 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*.

Demand response programs are treated as supply-side resources in the 2011 IRP and 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. Because energy efficiency programs also result in a reduction to peak demand, there is a component of peak-hour load reduction due to energy efficiency programs that is integrated into the sales and load forecast. 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 2010 Annual Report*.

Appendix A1. Historical and Projected Sales and Load

Residential Load

Historical Residential Sales and Load, 1970–2010
(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	132,135		9,944	1,314		151
1971	138,071	4.5%	10,392	1,435	9.2%	165
1972	145,208	5.2%	10,838	1,574	9.7%	182
1973	152,957	5.3%	11,501	1,759	11.8%	202
1974	160,151	4.7%	12,099	1,938	10.1%	224
1975	167,622	4.7%	12,871	2,158	11.3%	249
1976	175,720	4.8%	13,544	2,380	10.3%	273
1977	184,561	5.0%	13,594	2,509	5.4%	288
1978	194,650	5.5%	14,427	2,808	11.9%	325
1979	202,982	4.3%	14,821	3,008	7.1%	343
1980	209,629	3.3%	14,741	3,090	2.7%	352
1981	213,579	1.9%	14,416	3,079	-0.4%	352
1982	216,696	1.5%	14,627	3,170	2.9%	362
1983	219,849	1.5%	14,430	3,172	0.1%	366
1984	222,695	1.3%	14,438	3,215	1.4%	364
1985	225,185	1.1%	14,375	3,237	0.7%	371
1986	227,081	0.8%	14,244	3,234	-0.1%	368
1987	228,868	0.8%	14,037	3,213	-0.7%	365
1988	230,771	0.8%	14,282	3,296	2.6%	376
1989	233,370	1.1%	14,463	3,375	2.4%	386
1990	238,117	2.0%	14,236	3,390	0.4%	393
1991	243,207	2.1%	14,654	3,564	5.1%	404
1992	249,767	2.7%	14,062	3,512	-1.5%	405
1993	258,271	3.4%	14,392	3,717	5.8%	419
1994	267,854	3.7%	13,957	3,738	0.6%	433
1995	277,131	3.5%	14,067	3,898	4.3%	440
1996	286,227	3.3%	13,759	3,938	1.0%	456
1997	294,674	3.0%	13,692	4,035	2.4%	464
1998	303,300	2.9%	13,727	4,164	3.2%	475
1999	312,901	3.2%	13,616	4,260	2.3%	488
2000	322,402	3.0%	13,409	4,323	1.5%	500
2001	331,009	2.7%	13,156	4,355	0.7%	476
2002	339,764	2.6%	12,616	4,286	-1.6%	487
2003	349,219	2.8%	12,639	4,414	3.0%	507
2004	360,462	3.2%	12,689	4,574	3.6%	525
2005	373,602	3.6%	12,687	4,740	3.6%	543
2006	387,707	3.8%	12,872	4,991	5.3%	568
2007	397,286	2.5%	12,940	5,141	3.0%	585
2008	402,520	1.3%	12,858	5,176	0.7%	594
2009	405,144	0.7%	12,696	5,144	-0.6%	585
2010	407,551	0.6%	12,441	5,070	-1.4%	582

Residential Load

Projected Residential Sales and Load, 2011–2030

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2011	411,162	0.9%	12,677	5,212	2.8%	595
2012	415,787	1.1%	12,514	5,203	-0.2%	594
2013	423,098	1.8%	12,350	5,225	0.4%	598
2014	432,043	2.1%	12,425	5,368	2.7%	614
2015	440,364	1.9%	12,441	5,478	2.1%	626
2016	447,754	1.7%	12,425	5,563	1.6%	636
2017	454,724	1.6%	12,468	5,669	1.9%	648
2018	461,592	1.5%	12,473	5,757	1.6%	658
2019	468,394	1.5%	12,530	5,869	1.9%	671
2020	475,070	1.4%	12,568	5,971	1.7%	682
2021	481,514	1.4%	12,578	6,056	1.4%	692
2022	487,734	1.3%	12,627	6,159	1.7%	704
2023	493,690	1.2%	12,703	6,271	1.8%	717
2024	499,477	1.2%	12,737	6,362	1.4%	727
2025	505,167	1.1%	12,722	6,427	1.0%	734
2026	510,811	1.1%	12,745	6,510	1.3%	743
2027	516,404	1.1%	12,691	6,554	0.7%	749
2028	521,918	1.1%	12,851	6,707	2.3%	766
2029	527,380	1.0%	12,849	6,776	1.0%	774
2030	532,835	1.0%	12,908	6,878	1.5%	786

Commercial Load

Historical Commercial Sales and Load, 1970–2010
(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	21,375		42,773	914		105
1971	22,077	3.3%	45,388	1,002	9.6%	115
1972	22,585	2.3%	46,142	1,042	4.0%	120
1973	23,286	3.1%	48,144	1,121	7.6%	128
1974	24,096	3.5%	49,027	1,181	5.4%	136
1975	25,045	3.9%	51,218	1,283	8.6%	147
1976	26,034	3.9%	52,512	1,367	6.6%	157
1977	27,112	4.1%	52,414	1,421	3.9%	162
1978	27,831	2.7%	52,474	1,460	2.8%	169
1979	28,087	0.9%	56,389	1,584	8.4%	180
1980	28,797	2.5%	54,141	1,559	-1.6%	178
1981	29,567	2.7%	54,282	1,605	2.9%	184
1982	30,167	2.0%	54,126	1,633	1.7%	186
1983	30,776	2.0%	52,684	1,621	-0.7%	186
1984	31,554	2.5%	53,410	1,685	3.9%	191
1985	32,417	2.7%	54,076	1,753	4.0%	201
1986	33,208	2.4%	53,747	1,785	1.8%	203
1987	33,975	2.3%	53,312	1,811	1.5%	206
1988	34,723	2.2%	54,432	1,890	4.4%	216
1989	35,638	2.6%	55,285	1,970	4.2%	226
1990	36,785	3.2%	55,761	2,051	4.1%	236
1991	37,922	3.1%	56,076	2,127	3.7%	243
1992	39,022	2.9%	56,359	2,199	3.4%	253
1993	40,047	2.6%	57,970	2,321	5.6%	263
1994	41,629	4.0%	58,246	2,425	4.4%	280
1995	43,165	3.7%	58,555	2,528	4.2%	287
1996	44,995	4.2%	61,960	2,788	10.3%	322
1997	46,819	4.1%	62,038	2,905	4.2%	333
1998	48,404	3.4%	62,713	3,036	4.5%	347
1999	49,430	2.1%	64,186	3,173	4.5%	363
2000	50,117	1.4%	66,043	3,310	4.3%	383
2001	51,501	2.8%	67,454	3,474	5.0%	384
2002	52,915	2.7%	64,719	3,425	-1.4%	390
2003	54,194	2.4%	64,320	3,486	1.8%	399
2004	55,577	2.6%	63,898	3,551	1.9%	407
2005	57,145	2.8%	63,527	3,630	2.2%	415
2006	59,050	3.3%	63,487	3,749	3.3%	427
2007	61,640	4.4%	63,330	3,904	4.1%	445
2008	63,492	3.0%	62,249	3,952	1.2%	451
2009	64,151	1.0%	59,635	3,826	-3.2%	437
2010	64,421	0.4%	58,851	3,791	-0.9%	434

Commercial Load

Projected Commercial Sales and Load, 2011–2030

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2011	64,995	0.9%	59,059	3,839	1.2%	439
2012	66,265	2.0%	58,734	3,892	1.4%	445
2013	67,892	2.5%	58,122	3,946	1.4%	451
2014	69,600	2.5%	57,471	4,000	1.4%	457
2015	71,252	2.4%	56,873	4,052	1.3%	463
2016	72,840	2.2%	56,204	4,094	1.0%	468
2017	74,398	2.1%	55,579	4,135	1.0%	472
2018	75,950	2.1%	54,977	4,176	1.0%	477
2019	77,497	2.0%	54,399	4,216	1.0%	482
2020	79,031	2.0%	53,841	4,255	0.9%	486
2021	80,551	1.9%	53,342	4,297	1.0%	491
2022	82,058	1.9%	52,929	4,343	1.1%	496
2023	83,549	1.8%	52,592	4,394	1.2%	502
2024	85,030	1.8%	52,307	4,448	1.2%	508
2025	86,505	1.7%	52,116	4,508	1.4%	515
2026	87,976	1.7%	52,022	4,577	1.5%	523
2027	89,445	1.7%	51,979	4,649	1.6%	531
2028	90,906	1.6%	52,057	4,732	1.8%	541
2029	92,365	1.6%	52,166	4,818	1.8%	550
2030	93,823	1.6%	52,363	4,913	2.0%	561

Irrigation Load

Historical Irrigation Sales and Load,1970–2010

(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	7,319		126,039	922		105
1971	7,518	2.7%	136,020	1,023	10.9%	117
1972	7,815	4.0%	131,163	1,025	0.2%	117
1973	8,341	6.7%	140,226	1,170	14.1%	134
1974	8,971	7.6%	147,179	1,320	12.9%	151
1975	9,480	5.7%	154,226	1,462	10.7%	167
1976	9,936	4.8%	152,340	1,514	3.5%	172
1977	10,238	3.0%	160,870	1,647	8.8%	188
1978	10,476	2.3%	152,800	1,601	-2.8%	183
1979	10,711	2.2%	159,986	1,714	7.1%	195
1980	10,854	1.3%	154,900	1,681	-1.9%	191
1981	11,248	3.6%	165,138	1,857	10.5%	212
1982	11,312	0.6%	150,370	1,701	-8.4%	194
1983	11,133	-1.6%	143,424	1,597	-6.1%	182
1984	11,375	2.2%	131,427	1,495	-6.4%	170
1985	11,576	1.8%	133,730	1,548	3.6%	177
1986	11,308	-2.3%	134,686	1,523	-1.6%	174
1987	11,254	-0.5%	127,375	1,433	-5.9%	164
1988	11,378	1.1%	136,257	1,550	8.2%	176
1989	11,957	5.1%	137,704	1,647	6.2%	188
1990	12,340	3.2%	144,106	1,778	8.0%	203
1991	12,484	1.2%	133,777	1,670	-6.1%	191
1992	12,809	2.6%	139,469	1,786	7.0%	203
1993	13,078	2.1%	126,585	1,655	-7.3%	189
1994	13,559	3.7%	128,848	1,747	5.5%	199
1995	13,679	0.9%	125,761	1,720	-1.5%	196
1996	14,074	2.9%	123,537	1,739	1.1%	198
1997	14,383	2.2%	114,002	1,640	-5.7%	187
1998	14,695	2.2%	112,933	1,660	1.2%	189
1999	14,912	1.5%	117,103	1,746	5.2%	199
2000	15,253	2.3%	125,903	1,920	10.0%	219
2001	15,522	1.8%	115,103	1,787	-7.0%	204
2002	15,840	2.0%	109,768	1,739	-2.7%	198
2003	16,020	1.1%	108,979	1,746	0.4%	199
2004	16,297	1.7%	106,547	1,736	-0.5%	198
2005	16,936	3.9%	98,843	1,674	-3.6%	191
2006	17,062	0.7%	96,848	1,652	-1.3%	189
2007	17,001	-0.4%	104,905	1,783	7.9%	204
2008	17,428	2.5%	108,350	1,888	5.9%	215
2009	17,708	1.6%	100,186	1,774	-6.0%	203
2010	17,846	0.8%	99,148	1,769	-0.3%	202

Irrigation Load

Projected Irrigation Sales and Load, 2011–2030

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2011	18,264	2.3%	94,526	1,726	-2.4%	197
2012	18,541	1.5%	93,518	1,734	0.4%	197
2013	18,821	1.5%	91,968	1,731	-0.2%	198
2014	19,101	1.5%	90,686	1,732	0.1%	198
2015	19,379	1.5%	90,049	1,745	0.7%	199
2016	19,655	1.4%	89,212	1,753	0.5%	200
2017	19,932	1.4%	88,237	1,759	0.3%	201
2018	20,212	1.4%	87,324	1,765	0.4%	201
2019	20,487	1.4%	86,337	1,769	0.2%	202
2020	20,767	1.4%	85,426	1,774	0.3%	202
2021	21,045	1.3%	84,531	1,779	0.3%	203
2022	21,323	1.3%	83,591	1,782	0.2%	203
2023	21,601	1.3%	82,745	1,787	0.3%	204
2024	21,878	1.3%	81,991	1,794	0.4%	204
2025	22,157	1.3%	81,160	1,798	0.2%	205
2026	22,437	1.3%	80,269	1,801	0.2%	206
2027	22,712	1.2%	79,463	1,805	0.2%	206
2028	22,988	1.2%	78,494	1,804	0.0%	205
2029	23,268	1.2%	77,943	1,814	0.5%	207
2030	23,547	1.2%	77,079	1,815	0.1%	207

Industrial Load

Historical Industrial Sales and Load, 1970–2010
(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	49		9,173,784	445		52
1971	50	3.3%	10,474,941	525	17.9%	60
1972	56	12.1%	10,944,714	615	17.2%	71
1973	63	12.3%	10,889,056	687	11.7%	79
1974	65	2.2%	11,464,249	739	7.6%	84
1975	71	10.5%	11,014,121	785	6.1%	91
1976	73	3.0%	11,681,540	858	9.3%	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%	18,310,726	2,220	-0.2%	254

Industrial Load

Projected Industrial Sales and Load, 2011–2030

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2011	121	-0.2%	18,958,898	2,294	3.3%	262
2012	125	3.3%	18,768,661	2,346	2.3%	268
2013	125	0.0%	19,133,471	2,392	1.9%	273
2014	126	0.8%	19,320,558	2,434	1.8%	278
2015	128	1.6%	19,318,966	2,473	1.6%	283
2016	131	2.3%	19,155,425	2,509	1.5%	286
2017	134	2.3%	18,997,015	2,546	1.4%	291
2018	134	0.0%	19,256,620	2,580	1.4%	295
2019	136	1.5%	19,239,155	2,617	1.4%	299
2020	139	2.2%	19,087,337	2,653	1.4%	302
2021	140	0.7%	19,218,638	2,691	1.4%	308
2022	142	1.4%	19,241,280	2,732	1.5%	312
2023	142	0.0%	19,514,996	2,771	1.4%	317
2024	145	2.1%	19,391,910	2,812	1.5%	321
2025	147	1.4%	19,454,919	2,860	1.7%	327
2026	148	0.7%	19,673,262	2,912	1.8%	333
2027	149	0.7%	19,892,894	2,964	1.8%	339
2028	152	2.0%	19,876,216	3,021	1.9%	344
2029	155	2.0%	19,862,920	3,079	1.9%	352
2030	156	0.6%	20,124,445	3,139	2.0%	359

Additional Firm Sales and Load*

Historical Additional Firm Sales and Load, 1970–2010

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	319		36
1971	295	-7.5%	34
1972	284	-3.7%	32
1973	291	2.2%	33
1974	282	-2.9%	32
1975	314	11.1%	36
1976	277	-11.8%	31
1977	311	12.4%	36
1978	357	14.9%	41
1979	373	4.3%	43
1980	360	-3.4%	41
1981	377	4.7%	43
1982	367	-2.5%	42
1983	425	15.8%	49
1984	466	9.6%	53
1985	471	1.1%	54
1986	483	2.5%	55
1987	503	4.2%	57
1988	531	5.6%	60
1989	671	26.5%	77
1990	625	-6.8%	71
1991	661	5.7%	75
1992	681	3.0%	78
1993	689	1.2%	79
1994	741	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	1,122	0.8%	128
2000	1,143	1.9%	130
2001	1,119	-2.1%	128
2002	1,139	1.8%	130
2003	1,120	-1.6%	128
2004	1,157	3.3%	132
2005	1,176	1.6%	134
2006	1,189	1.2%	136
2007	1,142	-4.0%	130
2008	1,114	-2.4%	127
2009	965	-13.4%	110
2010	907	-6.1%	103

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

Additional Firm Sales and Load*			
Projected Additional Firm Sales and Load, 2011–2030			
Year	**Billed Sales (thousands of MWh)**	**Percent Change**	**Average Load (MW)**
2011	1,449	59.9%	165
2012	1,627	12.3%	185
2013	1,799	10.6%	205
2014	1,902	5.7%	217
2015	2,002	5.3%	229
2016	2,071	3.4%	236
2017	2,065	-0.3%	236
2018	2,070	0.2%	236
2019	2,075	0.2%	237
2020	2,073	-0.1%	236
2021	2,075	0.1%	237
2022	2,082	0.3%	238
2023	2,089	0.4%	238
2024	2,096	0.3%	239
2025	2,101	0.2%	240
2026	2,112	0.5%	241
2027	2,113	0.0%	241
2028	2,119	0.3%	241
2029	2,119	0.0%	242
2030	2,125	0.3%	243

*Includes Micron Technology, Simplot Fertilizer, INL, Hoku Materials, "Special", and Raft River Rural Electric Cooperative, Inc.

Company System Load (excluding Astaris)

Historical Company System Sales and Load, 1970–2010
(weather-adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	3,915		494
1971	4,279	9.3%	539
1972	4,540	6.1%	573
1973	5,027	10.7%	634
1974	5,461	8.6%	690
1975	6,001	9.9%	758
1976	6,395	6.6%	806
1977	6,817	6.6%	858
1978	7,199	5.6%	912
1979	7,766	7.9%	976
1980	7,796	0.4%	977
1981	8,066	3.5%	1,015
1982	8,033	-0.4%	1,009
1983	8,009	-0.3%	1,012
1984	8,144	1.7%	1,018
1985	8,367	2.7%	1,053
1986	8,382	0.2%	1,050
1987	8,434	0.6%	1,056
1988	8,813	4.5%	1,104
1989	9,257	5.0%	1,164
1990	9,507	2.7%	1,201
1991	9,740	2.5%	1,218
1992	9,949	2.1%	1,254
1993	10,237	2.9%	1,275
1994	10,599	3.5%	1,340
1995	11,045	4.2%	1,375
1996	11,387	3.1%	1,437
1997	11,669	2.5%	1,469
1998	12,116	3.8%	1,517
1999	12,461	2.8%	1,564
2000	12,888	3.4%	1,627
2001	13,022	1.0%	1,592
2002	12,745	-2.1%	1,593
2003	13,000	2.0%	1,633
2004	13,287	2.2%	1,668
2005	13,571	2.1%	1,703
2006	13,906	2.5%	1,738
2007	14,336	3.1%	1,795
2008	14,439	0.7%	1,810
2009	13,933	-3.5%	1,746
2010	13,758	-1.3%	1,732

Company System Load (including Astaris)

Historical Company System Sales and Load, 1970–2010 Astaris Sales and Load (1970–2002)
(weather-adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)	Astaris Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	5,572		693	1,657		189
1971	5,787	3.9%	720	1,508	-9.0%	172
1972	6,359	9.9%	791	1,819	20.6%	207
1973	6,672	4.9%	831	1,645	-9.6%	188
1974	7,105	6.5%	887	1,643	-0.1%	188
1975	7,558	6.4%	945	1,557	-5.3%	178
1976	7,970	5.5%	995	1,575	1.2%	179
1977	8,234	3.3%	1,028	1,418	-10.0%	162
1978	8,741	6.2%	1,097	1,542	8.8%	176
1979	9,160	4.8%	1,143	1,395	-9.6%	159
1980	9,309	1.6%	1,157	1,513	8.5%	172
1981	9,700	4.2%	1,211	1,634	8.0%	186
1982	9,587	-1.2%	1,195	1,554	-4.9%	177
1983	9,619	0.3%	1,205	1,610	3.6%	184
1984	9,845	2.4%	1,221	1,701	5.7%	194
1985	9,980	1.4%	1,247	1,614	-5.1%	184
1986	9,935	-0.5%	1,236	1,554	-3.7%	177
1987	10,126	1.9%	1,259	1,692	8.9%	193
1988	10,448	3.2%	1,300	1,635	-3.4%	186
1989	10,961	4.9%	1,368	1,703	4.2%	194
1990	11,111	1.4%	1,394	1,604	-5.8%	183
1991	11,349	2.1%	1,411	1,609	0.3%	184
1992	11,519	1.5%	1,442	1,570	-2.4%	179
1993	11,674	1.3%	1,448	1,437	-8.4%	164
1994	12,019	3.0%	1,510	1,420	-1.2%	162
1995	12,612	4.9%	1,563	1,567	10.4%	179
1996	13,076	3.7%	1,639	1,689	7.8%	192
1997	13,297	1.7%	1,664	1,628	-3.6%	186
1998	13,389	0.7%	1,670	1,273	-21.8%	145
1999	13,512	0.9%	1,690	1,051	-17.4%	120
2000	13,942	3.2%	1,753	1,054	0.3%	120
2001	13,681	-1.9%	1,671	658	-37.5%	75
2002	12,757	-6.8%	1,594	11	-98.3%	1
2003	13,000	1.9%	1,633	0	-100.0%	0
2004	13,287	2.2%	1,668	0	0.0%	0
2005	13,571	2.1%	1,703	0	0.0%	0
2006	13,906	2.5%	1,738	0	0.0%	0
2007	14,336	3.1%	1,795	0	0.0%	0
2008	14,439	0.7%	1,810	0	0.0%	0
2009	13,933	-3.5%	1,746	0	0.0%	0
2010	13,758	-1.3%	1,732	0	0.0%	0

Company System Load

Projected Company System Sales and Load, 2011–2030

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2011	14,521	5.5%	1,819
2012	14,803	1.9%	1,852
2013	15,093	2.0%	1,890
2014	15,437	2.3%	1,932
2015	15,751	2.0%	1,970
2016	15,991	1.5%	1,998
2017	16,174	1.1%	2,023
2018	16,348	1.1%	2,045
2019	16,545	1.2%	2,070
2020	16,726	1.1%	2,090
2021	16,898	1.0%	2,114
2022	17,098	1.2%	2,139
2023	17,313	1.3%	2,166
2024	17,511	1.1%	2,189
2025	17,694	1.0%	2,214
2026	17,912	1.2%	2,241
2027	18,084	1.0%	2,263
2028	18,385	1.7%	2,298
2029	18,606	1.2%	2,329
2030	18,870	1.4%	2,362

Contract Off-System Load

Historical Contract Off-System Sales and Load, 1970–2010

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	386		44
1971	439	13.6%	50
1972	448	2.0%	51
1973	489	9.3%	56
1974	501	2.3%	57
1975	568	13.5%	65
1976	613	7.9%	70
1977	659	7.5%	75
1978	684	3.7%	78
1979	759	11.1%	87
1980	762	0.3%	87
1981	752	-1.2%	86
1982	736	-2.2%	84
1983	710	-3.5%	81
1984	747	5.2%	85
1985	779	4.3%	89
1986	670	-13.9%	77
1987	644	-4.0%	73
1988	675	4.9%	77
1989	740	9.7%	84
1990	968	30.8%	111
1991	1,537	58.8%	175
1992	1,348	-12.3%	154
1993	1,557	15.5%	178
1994	1,811	16.3%	207
1995	1,583	-12.6%	181
1996	1,285	-18.8%	146
1997	674	-47.5%	77
1998	716	6.2%	82
1999	568	-20.6%	65
2000	587	3.3%	67
2001	538	-8.4%	61
2002	454	-15.7%	52
2003	346	-23.6%	40
2004	19	-94.4%	2
2005	10	-47.0%	1
2006	0	-100.0%	0
2007	0	0.0%	0
2008	0	0.0%	0
2009	0	0.0%	0
2010	0	0.0%	0

Projected Contract Off-System Sales and Load, 2011–2030

2011–2030	0	0.0%	0

Total Company Load

Historical Total Company Sales and Load, 1970–2010

(weather-adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	5,958		738
1971	6,226	4.5%	772
1972	6,807	9.3%	844
1973	7,162	5.2%	889
1974	7,605	6.2%	946
1975	8,126	6.8%	1,012
1976	8,583	5.6%	1,067
1977	8,894	3.6%	1,106
1978	9,425	6.0%	1,178
1979	9,920	5.2%	1,233
1980	10,071	1.5%	1,247
1981	10,453	3.8%	1,300
1982	10,323	-1.2%	1,282
1983	10,329	0.1%	1,289
1984	10,592	2.5%	1,309
1985	10,759	1.6%	1,339
1986	10,605	-1.4%	1,315
1987	10,770	1.5%	1,335
1988	11,123	3.3%	1,379
1989	11,701	5.2%	1,455
1990	12,079	3.2%	1,508
1991	12,886	6.7%	1,592
1992	12,867	-0.1%	1,601
1993	13,231	2.8%	1,632
1994	13,830	4.5%	1,724
1995	14,195	2.6%	1,750
1996	14,361	1.2%	1,790
1997	13,971	-2.7%	1,744
1998	14,105	1.0%	1,754
1999	14,081	-0.2%	1,757
2000	14,529	3.2%	1,822
2001	14,219	-2.1%	1,735
2002	13,210	-7.1%	1,648
2003	13,347	1.0%	1,674
2004	13,306	-0.3%	1,670
2005	13,581	2.1%	1,704
2006	13,906	2.4%	1,738
2007	14,336	3.1%	1,795
2008	14,439	0.7%	1,810
2009	13,933	-3.5%	1,746
2010	13,758	-1.3%	1,732

Total Company Load			
Projected Total Company Sales and Load, 2011–2030			
Year	**Billed Sales (thousands of MWh)**	**Percent Change**	**Average Load (MW)**
2011	14,521	5.5%	1,819
2012	14,803	1.9%	1,852
2013	15,093	2.0%	1,890
2014	15,437	2.3%	1,932
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