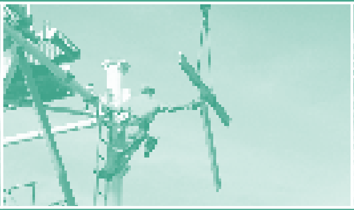
IDAHO POWER
An IDACORP Company

SALES AND LOAD FORECAST

FOR THE 2004 INTEGRATED RESOURCE PLAN



Providing a foundation for a bright future.

IDAHO POWER
An IDACORP Company

SALES AND LOAD FORECAST

FOR THE 2004 INTEGRATED RESOURCE PLAN

July 2004

Table of Contents

List of Tables

List of Figures

Introduction

Idaho Power Company (Idaho Power or the Company) has prepared the 2004 Sales and Load Forecast as an appendix to its 2004 Integrated Resource Plan (IRP). The Sales and Load Forecast presents the Company's best estimate of the future demand for electricity within its service territory. The forecast covers the 10-year period from 2004 through 2013. For planning purposes, the future demand for electricity by customers in the Company's service territory is represented by three load forecasts: (1) a 50^{th} percentile or expected case load forecast, (2) a 70^{th} percentile load forecast, and (3) a 90^{th} percentile load forecast. These forecasts define three possible load conditions evaluated in the 2004 IRP. The expected case total load growth rate is 2.2 percent per year over the ten-year planning period. This is 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 the Company's service territory.

Two additional load forecasts for the Idaho Power service territory were prepared that provide a range of possible load growths for the 2004-2013 planning period due to variable economic and demographic conditions. The high economic growth and low economic growth scenarios were prepared based upon statistical analysis to empirically reflect uncertainty inherent in the load forecast.

The expected case load forecast assumes median temperatures and median rainfall. Since actual loads can vary significantly dependent upon weather conditions, two alternative scenarios were considered to address the load variability due to weather. A 70th percentile load forecast and 90th percentile 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 3 out of 10 years (30 percent of the time). The 90th percentile load forecast assumes monthly loads that can be exceeded in 1 out of 10 years (10 percent of the time).

In the expected case scenario, total company load is forecast to increase to 2,049 average megawatts in the year 2013 from the 2004 forecast load of 1,678 average megawatts. The expected case forecast total load growth rate averages 2.2 percent per year over the 10 years of the planning period (2004-2013). The number of Idaho Power retail customers increases from the December 2003 level of 423,167 customers to about 516,900 retail customers at year-end 2013. The Company system peak load is forecast to grow to 3,794 megawatts in the year 2013 from the 2003 actual system peak of 2,944 megawatts. The highest system peak on record was 2,963 megawatts and occurred on July 12, 2002 at 4:00 p.m. In the expected case scenario, the Company system peak increases at an average growth rate of 2.5 percent per year over the 10 years of the planning period (2004–2013).

This Sales and Load Forecast is strongly influenced by the 2004 Economic Forecast developed by an outside consultant, John Church of Idaho Economics. The 2004 Economic Forecast is based on the Global Insight forecast of national and regional economic activity. The Global Insight economic forecast is modified by Idaho Economics to reflect anticipated service area conditions.

Economic growth assumptions influence several of the individual class of service growth rates. Economic growth information for Idaho and its counties can be found in Appendix A, 2004 Economic Forecast. The number of households in the state of Idaho is projected to grow at an annual average rate of 1.6 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 and employment projections along with customer consumption patterns are each used to form 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 these assumptions is presented in the sections of this report pertaining to these individual sectors.

The future load impacts of previous, ongoing, and future Idaho Power conservation programs are not explicitly considered within the 2004 Sales and Load Forecast. These programs, and their expected impacts are addressed in more detail in the Company's 2004 Conservation Plan. This plan is an additional appendix to the 2004 IRP.

The expected case load forecast represents Idaho Power's most probable outcome for load growth during the planning period. However, the actual path of future electricity sales will not follow exactly the 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 growth" and "low growth" scenarios provide boundaries on each side of the expected case scenario and reflect economic uncertainty. The "70th percentile" and "90th percentile" load forecast scenarios were developed to assist the Company in reviewing the resource requirements that would result from higher loads due to more adverse weather.

Several recent topics that were not considered in the development of the 2004 Sales and Load Forecast include seasonal rates, time-of-use rates, and block rates that were each implemented in June of 2004. Idaho Power expects to address the impacts of these significant changes to rate structure in the 2006 IRP.

During the 10-year forecast horizon there could be major changes in the electric utility industry. However, the implications of any major changes are unknown at this time and are not reflected in this forecast. The alternative sales and load scenarios of the 2004 Sales and Load Forecast were prepared under the assumption that Idaho Power will continue to serve all customers in its franchised service territory during the planning period.

2004 IRP versus 2002 IRP

Average Load Comparisons

The 2004 IRP average load forecast is lower than the 2002 IRP average load forecast. An additional year of higher electricity prices (due to the 2002/2003 Power Cost Adjustment rate increase) combined with a weak national and service area economy temporarily stalled load growth. However, the reduction in electricity prices in May 2003 and a slow recovery in the service area economy have already caused some load growth to return, although at a slower pace than before and starting at a lower level than previously forecast in the 2002 IRP. Significant factors that influenced the outcome of the 2004 IRP load forecast include:

- A much weaker service area economy experienced in the past few years.
- A slower growing service area economic forecast from Idaho Economics.
- Two years of significantly higher retail electricity prices.
- Electricity prices in the 2002 IRP were assumed to only remain significantly higher for one year.
- The 2004 IRP residential, commercial, and industrial load forecasts are each lower than the 2002 IRP forecast.
- In April 2002 the special contract between Astaris and Idaho Power Company was terminated. Astaris had been the Company's largest individual customer and in some past years had averaged nearly 200 average megawatts.
- A flat load forecast was assumed for the INEEL in this year's forecast compared to expanding load growth assumed in the 2002 IRP.
- Simplot Fertilizer loads have actually dropped by 30% compared to steady growth assumed in the 2002 IRP.
- Initially, slower growth at Micron Technology than assumed in 2002 IRP.
- Sales to City of Weiser and Raft River Rural Electric Cooperative, Inc. are forecast to be somewhat slower than that assumed in the 2002 IRP.

Peak Hour Comparisons

Average loads and peak day temperatures drive the peak model regressions. The lower average loads forecast in the 2004 IRP resulted, in most cases, in lower monthly peak forecast figures. However, the peak forecast results and comparisons with the last IRP differ for a number of reasons that include:

- The update of the 12 peak model regressions using MetrixND (a statistical software from RER, an Itron Company).

- The re-specification of the winter month peak equations (October-April).

- The winter equations previously were constructed using Box-Jenkins transformations that utilized three temperature intervals as drivers. The new monthly models use only one temperature driver. This results in more reasonable results especially when analyzing the various probabilities of peak day temperatures.

- The modeling procedure in the 2004 IRP peak model was carefully reviewed and logic changes were made to more accurately forecast the peaks at various percentiles of temperatures.

- The new peak model allows peaks to be calculated at 0, 10, 20, 30, 40, 50, 60, 70, 80, 90, 95, and 100 percentiles of peak day temperatures for each month of the year.

- The addition of more recent peak data to the peak model regressions. The August 2001, July 2002, and July 2003 peak day temperatures were near the 100th percentile and their addition to the regression models impacted forecast results.

- The 2002 IRP summer peak regression models didn't use the 2001 peak data as the 2001 voluntary load reduction program, that paid irrigators not to use electricity, impacted the 2001 peaks.

- The Company continues to utilize 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 occurrence. Peak day temperatures are not normally distributed and can be skewed by one or more extreme observations and the median temperature better reflects expected temperatures.

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 Micron Technology, Simplot Fertilizer Company, Idaho National Engineering and Environmental Laboratory (INEEL), the City of Weiser, and Raft River Rural Electric Cooperative, Inc. (the electric distribution utility serving Idaho Power Company's former customers in the state of Nevada). These five special contract customers are combined into a single forecast category labeled Additional Firm Load. Lastly, the contract off-system category represents long-term contracts to supply firm energy and demand to off-system customers. The assumptions for each of the individual categories are described in greater detail in their 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 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 2004 sales forecast. Idaho Power has two distinct peak periods: a winter peak resulting from space heating demand that normally occurs in December or January, and a larger summer peak that normally occurs in June or July. The summer peak generally occurs when extensive air conditioning usage coincides with significant irrigation demand.

Peak loads are forecast via twelve regression equations and are a function of temperature, space heating saturation (winter only), air-conditioning saturation (summer only), nonweather-sensitive base load, and precipitation (summer only). The peak forecast utilizes a statistically derived peak day temperatures based on 30 or more years of climate data for each month. Peak loads for the INEEL, Micron Technology, Simplot Fertilizer, the City of Weiser, Raft River Rural Electric Cooperative, Inc., and the firm off-system contracts are forecast based on historical analysis and contractual considerations.

The primary exogenous factors in the forecast are macroeconomic and demographic data. Global Insight, a national econometric consulting firm, provides the macroeconomic forecasts. The national econometric projections are tailored to Idaho Power's service area. Specific demographic projections are developed for the service area from national and local census data.

Fuel Prices

Fuel prices, in combination with service area economic data, impact long-term trends in electricity sales. Changes in relative fuel prices can also have significant impacts on the future demand for electricity.

Global Insight provides the forecasts of long-term changes in nominal electricity and nominal natural gas prices. Short-term electricity prices are generated internally from Idaho Power financial models. 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.

Residential Fuel Price Escalation, 2004-2013

(average annual percent change)

	Nominal	***Real****
Electricity	1.4%	-1.1%
Natural Gas	0.8%	-1.6%

** adjusted for inflation*

table 1

Figure 1 illustrates electricity prices (in cents per kWh) over the historical period 1973 through 2003 and over the forecast period 2004 through 2015. Both nominal and real prices are shown. Current nominal electricity prices are expected to decline through 2005 and then slowly climb to nearly seven cents per kWh by the end of the forecast period. Real electricity prices (inflation-adjusted) are expected to decline over the forecast period at an average rate of 1.1 percent each year.

Forecasted Electricity Prices

(cents per kWh)

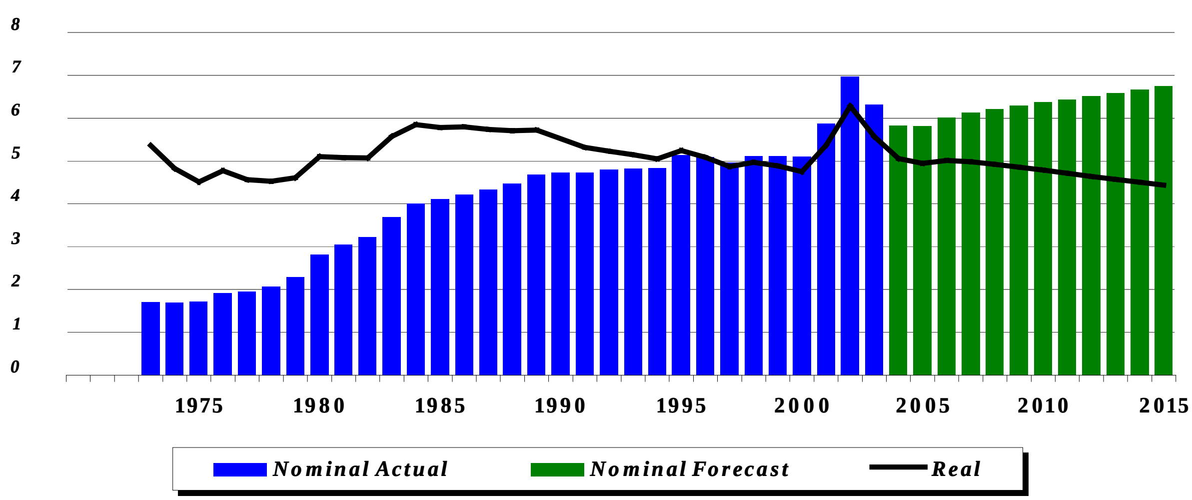


figure 1

Electricity prices for Idaho Power customers were significantly higher in 2002 and 2003 because of the Power Cost Adjustment impact on rates. However, as of 2004, electricity prices for Idaho Power customers are projected to return to levels closer to normal, at between five and six cents per kWh for residential customers. Except for the past three years, Idaho Power's electricity prices have been historically quite stable. Over the 1990 through 2000 period electricity prices rose only eight percent overall, an annual average compound growth rate of 0.8 percent each year.

Figure 2 illustrates the average natural gas price (in dollars per therm) paid by residential customers over the historical period 1973 through 2003 and over the forecast period 2004 through 2015. Natural gas prices remained stable and flat throughout the 1990s before moving sharply higher in 2001. Since 2001, natural gas prices have continued to remain at significantly higher price levels. Natural gas prices are expected to again move upward in 2004 to a price level sixty percent above the prices experienced throughout the 1990s.

Forecasted Natural Gas Prices

(dollars per therm)

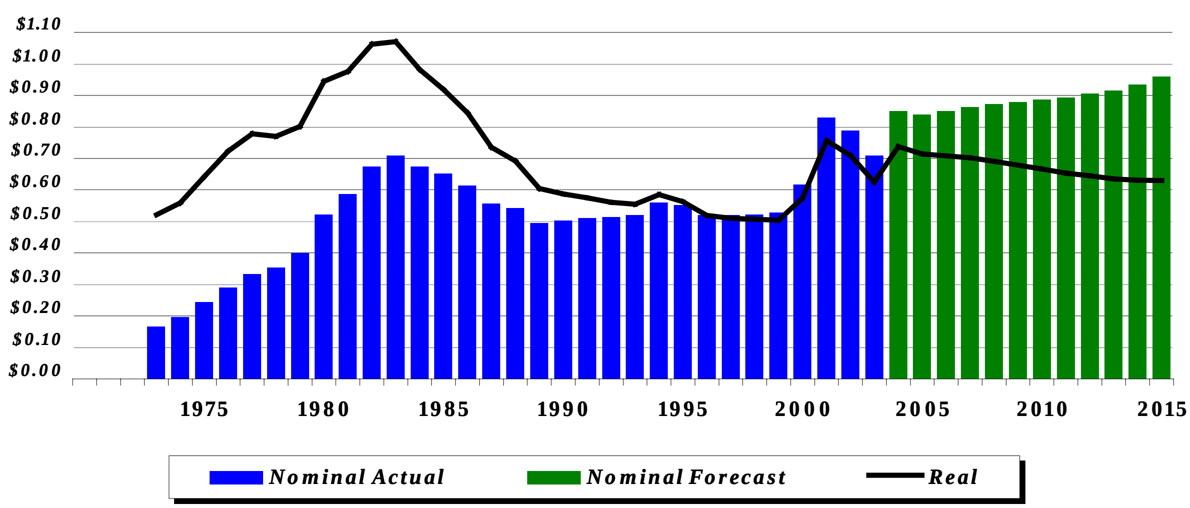


figure 2

Nominal natural gas prices are expected to continue upward throughout the forecast period (2004-2013) at an average rate of 0.8 percent per year. Real natural gas prices (adjusted for inflation) are expected to decline over the same period at an average rate of 1.6 percent each year.

If natural gas prices continue to outpace electricity prices, as they have over the past several years, at some point the operating costs of space heating and water heating homes with electricity will become comparable with that of natural gas. Eventual price parity could have a significant impact on future electricity demands.

Forecast Probabilities

Load Forecasts Based on Weather Variability

The future demand for electricity by customers in Idaho Power's service territory 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 economic forecast for the Company'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 dependant upon 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 heating degree days are assumed in winter and the lowest recorded levels of cooling and growing degree days 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 1948-2003 period was 1,040 HDD. The 70th percentile HDD is 1,068 HDD and would be exceeded in three out of ten years. The 90th percentile HDD is 1,194 HDD and would be exceeded in one out of ten years. The 100th percentile HDD (the coldest December on record) 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 the 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 dependant upon weather and these two scenarios allow us to carefully examine load variability and how it may impact 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 the year would be much less probable. It is the monthly forecast numbers that are being evaluated for resource planning and one must be careful in interpreting the meaning of the annual average load figures being reported and graphed.

The load scenarios prepared for the 2004 Integrated Resource Plan are summarized in *table 2*, below. Three average load scenarios were prepared based upon a statistical analysis of historical monthly weather variables listed. The probability associated with each individual average scenario is also indicated in the table. In addition, three peak demand scenarios were prepared based upon a statistical analysis of historical peak day temperatures. The probability associated with each individual peak demand scenario is also indicated in *table 2*.

The analysis of resource requirements is based on the 70th percentile average load forecast coupled with the 90th percentile peak demand forecast so that a more adverse representation of peak demands could be considered. Alternatively, the expected case average load forecast and the 50th percentile peak demand forecast were coupled together for consideration, as well as the 90th percentile average load forecast and 95th percentile peak demand forecast.

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 year	HDD, CDD, GDD, Prec.
70th Percentile	70%	3 in 10 year	HDD, CDD, GDD, Prec.
Expected Case	50%	1 in 2 year	HDD, CDD, GDD, Prec.
		Forecasts of Peak Demand	
Scenario	***Weather Probability***	***Probability of Exceeding***	***Weather Driver***
95th Percentile	95%	1 in 20 year	Peak Day Temperatures
90th Percentile	90%	1 in 10 year	Peak Day Temperatures
50th Percentile	50%	1 in 2 year	Peak Day Temperatures

table 2

Load Forecasts Based On Economic Uncertainty

The expected case load forecast is based on the most recent economic forecast for the Company's service territory and represents Idaho Power's most probable outcome for load growth during the planning period. Two additional load forecasts for the Idaho Power service territory were prepared that provide a range of possible load growths for the 2004-2013 planning period due to variable economic and demographic conditions. The high economic growth and low economic growth scenarios were prepared based upon 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 period 1979 through 2003.

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 firm sales observed between 1979 and 2003. 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; that is, 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 (1979 through 2003).

Forecast Probabilities

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

table 3

Two types of probability estimates are reported in *table 3*. The first probability shows the likelihood that the load growth rate in the specified scenario will be exceeded. For example, over the next 10 years there is a 10 percent probability that the actual growth rate will exceed the growth rate projected in the high scenario, and conversely, a 10 percent chance that the actual growth rate would fall below that of the low scenario. In other words, over a 10-year time period there is an 80 percent probability that the actual growth rate of firm 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 10-year planning horizon. Probabilities for shorter 1-year and 5-year time periods are also shown in *table 3*.

Firm Load Growth

(average megawatts)

Scenario	***2003***	***2008***	***2013***	***Growth Rate (% Per Year) 2003-2013***
High Growth	1,631	1,960	2,228	3.2
Expected Case	1,631	1,846	2,049	2.3
Low Growth	1,631	1,747	1,893	1.5

table 4

Firm load includes the sum of residential, commercial, industrial, irrigation, as well as special contracts (excluding Astaris), the City of Weiser, and Raft River Rural Electric Cooperative, Inc. Company firm load projections are reported in *table 4* and pictured in *figure 3*. The expected case firm load forecast growth rate averages 2.3 percent per year over the 10 years of the planning period. The low scenario projects that firm load will increase at an average rate of 1.5 percent per year throughout the forecast period. The high scenario projects load growth of 3.2 percent per year. The Company 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 Company's historical experience.

Forecasted Firm Load

(average megawatts)

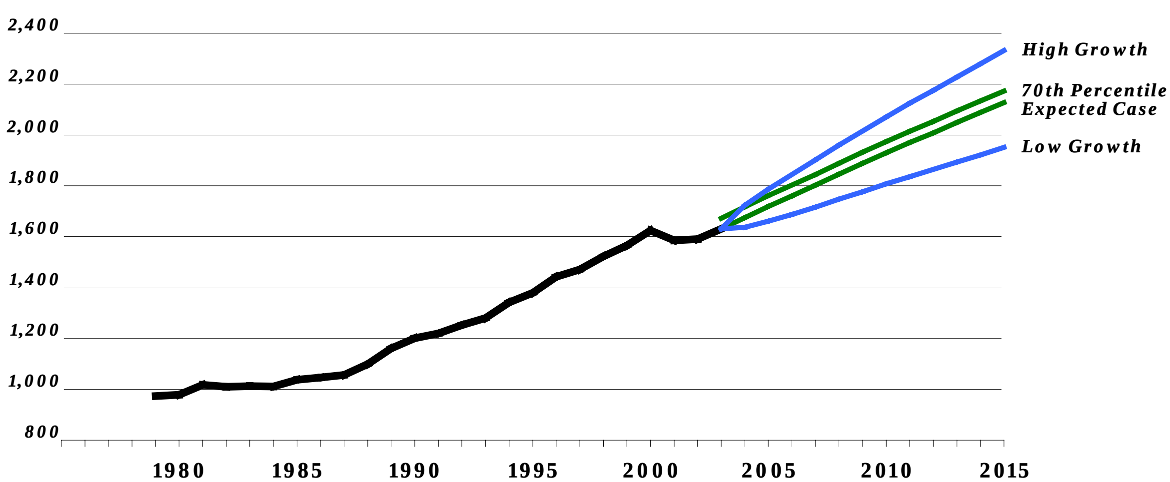


figure 3

The remainder of the 2004 Sales and Load Forecast document is organized by individual sectors. All information pertaining to a particular sector can be found under the appropriate heading.

Residential

Residential Load Growth

(average megawatts)

	2003	2008	2013	Growth Rate (% Per Year) 2003-2013
90th Percentile	550	605	659	1.8
70th Percentile	521	573	624	1.8
Expected Case	507	557	607	1.8

table 5

The expected case residential load is forecast to increase from 507 average megawatts in 2003 to 607 average megawatts in 2013; an average annual compound growth rate of 1.8 percent. In the 70^{th} percentile scenario residential load is forecast to increase from 521 average megawatts in 2003 to 624 average megawatts in 2013, matching the expected case residential growth rate. The residential load forecasts are reported in *table 5* and shown graphically in *figure 4*.

Forecasted Residential Load

(average megawatts)

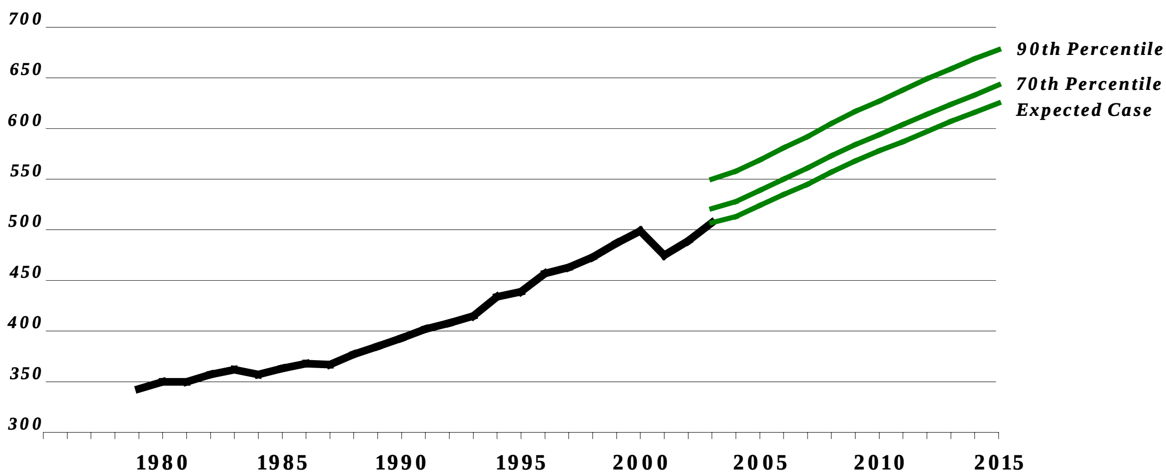


figure 4

Sales to residential customers made up 24 percent of the Company's system sales in 1970 and 34 percent of system sales in 2003. The residential customer proportion of system sales is forecast to be approximately 33 percent in 2013. There were 354,704 residential customers as of December 2003. The number of residential customers is projected to increase to around 431,667 by December 2013. The relative customer proportions of the total company electricity sales are shown in *figure 19* (page 29).

The average sales per residential customer were about 10,000 kWh in 1970. Average sales increased to nearly 14,800 kWh per residential customer in 1979 and declined to 13,100 kWh in 2001. In 2002 and 2003 residential use per customer dropped dramatically, about 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 mid-May 2003 and a recovery in the service area economy are expected to cause residential use per customer growth to return to a pattern of slow decline. The average sales per residential customer are expected to decline to approximately 12,400 kWh per year in 2013. Average annual sales per residential customer are shown in *figure 5*.

Forecasted Residential Use Per Customer

(weather adjusted kWh)

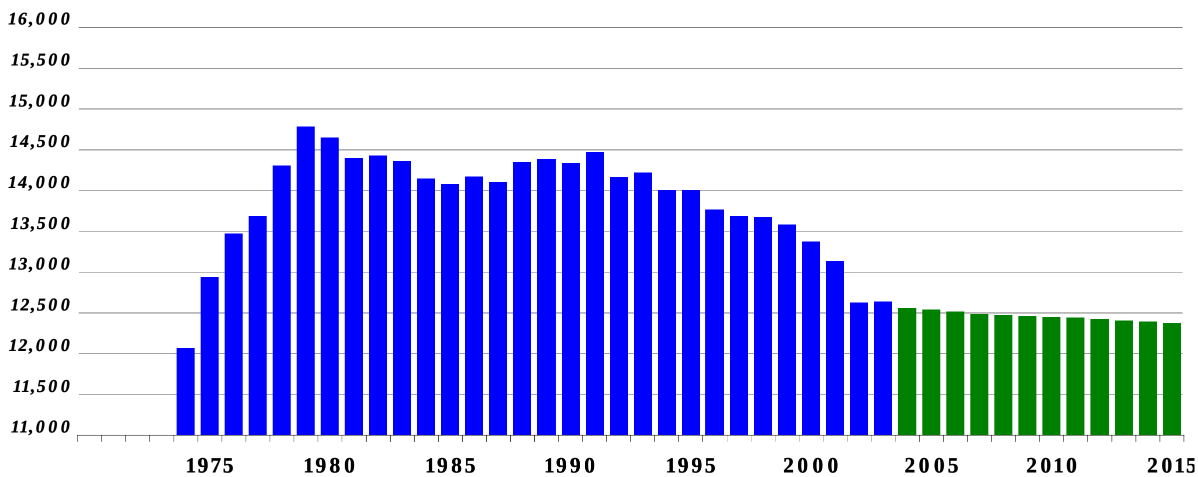


figure 5

The residential sales forecast is based on a forecast of the number of residential customers and an econometric analysis of residential use per customer. The number of residential customers being added each year is a direct function of new service area households provided by the 2004 Economic Forecast. The customer forecast for 2003-2013 shows an average annual growth rate of 2.1 percent.

The residential use per customer estimates consider several factors affecting electricity sales to residential customers. Residential use per customer is a function of HDD (wintertime), CDD (summertime), use per customer trends, and the price of electricity. The resulting forecast of residential use per customer is multiplied by the residential customer forecast to obtain the residential energy forecast.

Commercial

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

Commercial Load Growth

(average megawatts)

	2003	2008	2013	Growth Rate (% Per Year) 2003-2013
90th Percentile	414	497	572	3.3
70th Percentile	405	486	560	3.3
Expected Case	400	481	554	3.3

table 6

In the expected case scenario, commercial load is projected to increase from 400 average megawatts in 2003 to 554 average megawatts in 2013. The average annual compound growth rate of commercial load is 3.3 percent during the forecast period. As summarized in *table 6*, the commercial load in the 70th percentile scenario is projected to increase from 405 average megawatts in 2003 to 560 average megawatts in 2013. The commercial load forecasts are illustrated in *figure 6*.

Forecasted Commercial Load

(average megawatts)

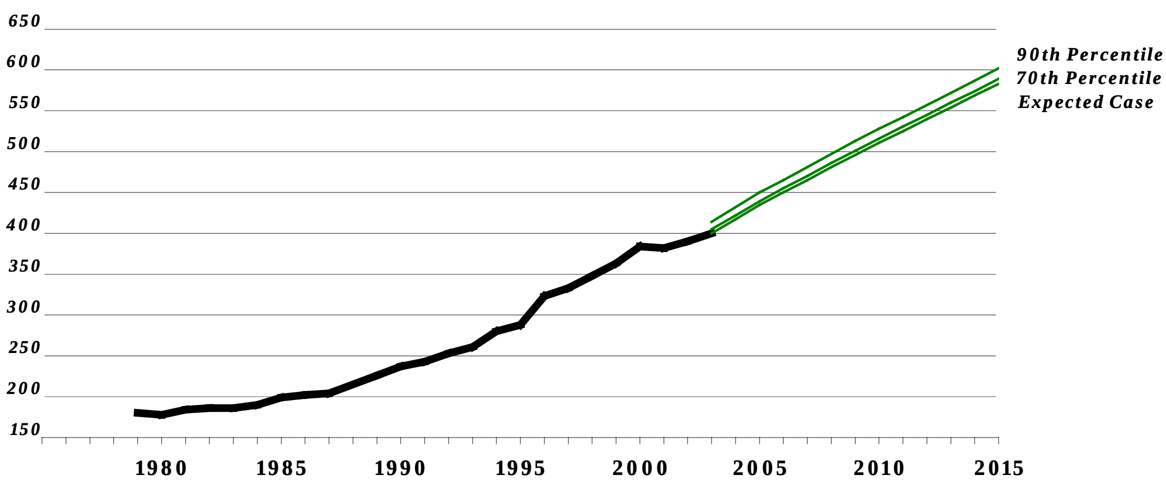


figure 6

As of December 2003, there were about 54,765 commercial customers. The number of commercial customers is expected to increase at an average annual growth rate of 2.3 percent, reaching 68,350 customers in 2013. Commercial customers comprised nearly 17 percent of the Company's system sales in 1970 and 27 percent of system sales in 2003. The commercial customer proportion of system sales is projected to increase to nearly 30 percent of system sales by 2013. The relative customer proportions of the Company's total electricity sales are shown in *figure 19* (page 29).

The average consumption per commercial customer increased to a record 67,286 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 in 2002 and 2003. The reduction in electricity prices in mid-May 2003 and a slow recovery in the service area economy are expected to cause commercial use per customer growth to return, although at a slower pace than before and starting at a lower level than previously forecast in the 2002 IRP. The average consumption per commercial customer is expected to increase to approximately 71,000 kWh per customer in 2013. Average annual use per commercial customer is pictured in *figure 7*.

Forecasted Commercial Use Per Customer

(weather adjusted kWh)

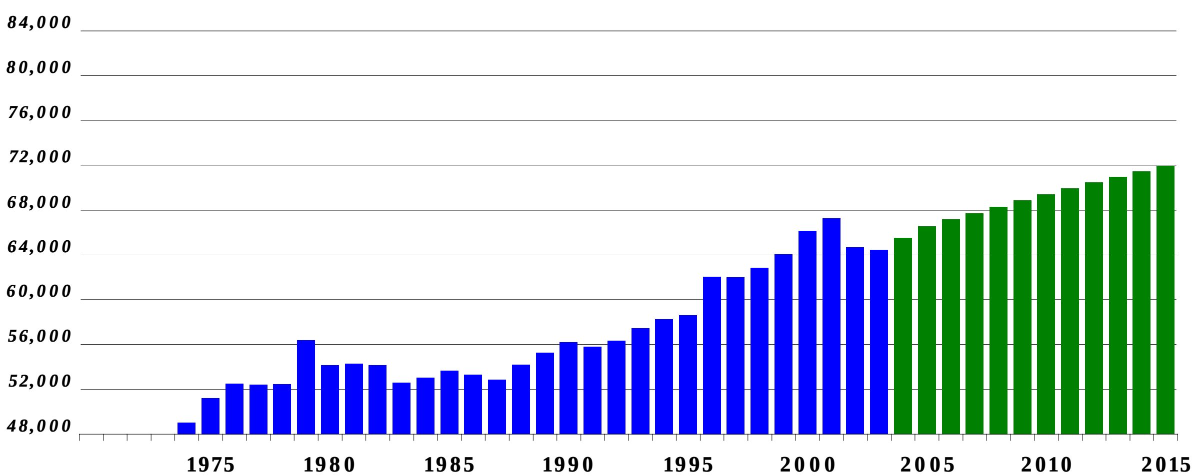


figure 7

The commercial sales forecast is based on a forecast of the number of commercial customers and an econometric analysis of commercial use per customer. The number of commercial customers being added each year is a direct function of the number of new residential customers being added. The number of residential customers being added is a direct function of the number of new service area households as provided by the 2004 Economic Forecast. The commercial customer forecast for 2003-2013 shows an average annual growth rate of 2.3 percent.

The commercial use per customer equation considers several factors affecting electricity sales to commercial customers. Commercial use per customer is a function of HDD (wintertime), CDD (summertime), use per customer trends, and electricity prices. The forecast of commercial use per customer is multiplied by the commercial customer forecast to obtain the commercial energy forecast.

Irrigation

The irrigation category is made up of Irrigation Service customers. Service under this Schedule is applicable to power and energy supplied to farm customers and organizations at one Point of Delivery for the operation of irrigation pump motors.

Irrigation Load Growth

(average megawatts)

	2003	***2008***	***2013***	***Growth Rate (% Per Year) 2003-2013***
90th Percentile	230	236	239	0.4
70th Percentile	208	215	218	0.4
Expected Case	190	197	200	0.5

table 7

The expected case irrigation load is forecast to increase from 190 average megawatts in 2003 to 200 average megawatts in 2013; an average annual compound growth rate of 0.5 percent. The expected case, 70th percentile, and 90th percentile scenarios forecast slow growth in irrigation load over the 2003-2013 time period. In the 70th percentile scenario, irrigation load is projected to increase from 208 average megawatts in 2003 to 218 average megawatts in 2013. The individual irrigation load forecasts are reported in *table 7* and shown graphically in *figure 8*. The figure graphically illustrates the poorer economic conditions and the drop-off in land development experienced by the agricultural economy in the mid-1980s.

Forecasted Irrigation Load

(average megawatts)

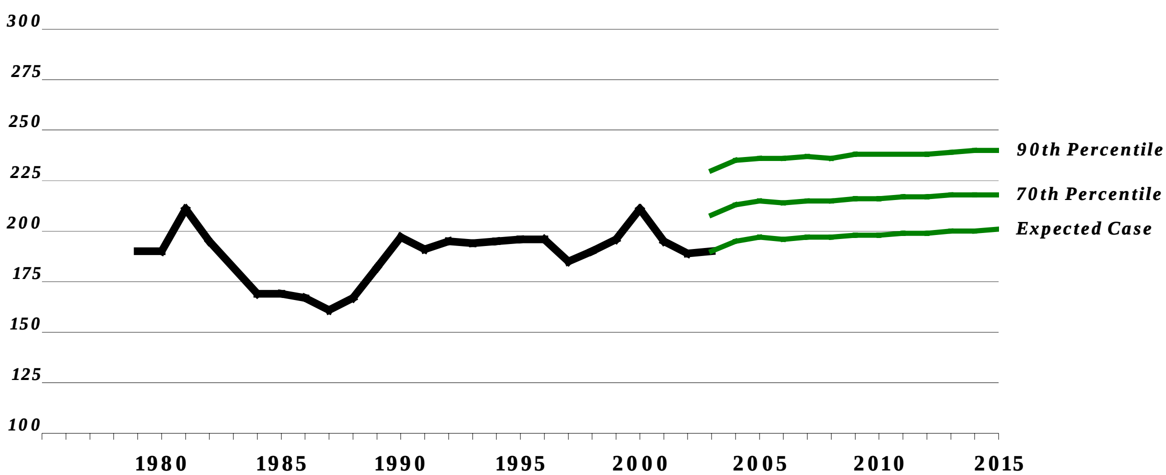


figure 8

In early 2001 wholesale electricity prices reached unprecedented levels and Idaho Power, in an attempt to minimize reliance on the market, developed a voluntary load reduction program that paid irrigators not to use electricity in 2001. The voluntary load reduction program was effective and resulted in a 30 percent reduction in 2001 irrigation sales or approximately 499,319 MWh. The 2001 irrigation sales and corresponding loads have been adjusted upward by 499,319 MWh to reflect a more normal 2001 irrigation season and at the same time obtain more reasonable growth rate calculations. In the future, Idaho Power does not anticipate that it will be necessary to implement similar load reduction programs to irrigators.

The 2004 irrigation sales forecast considers several factors affecting electricity sales to the irrigation class. Irrigation electricity sales are a function of temperatures, precipitation, spring rainfall, the price of electricity, and a linear trend component. Considerations are made for the unusually low electricity consumption in the 2001 crop year due to the voluntary load reduction program.

Actual irrigation electricity sales have grown from the 1970 level of 816,000 megawatt hours to a peak amount of 1,990,000 megawatt hours in 2000. During the period 1970 through 1996, the Company experienced an increase in electricity-using irrigated acres of 1,179,000 acres. This growth in total electricity-using irrigated acres represented approximately a 2.9 percent average annual compound rate of growth. The Company projects no growth in irrigated acres in the service area and limited growth in sprinkler irrigation or conversion to sprinkler irrigation.

Irrigation sales represented nearly 16 percent of weather-normalized company system sales in 1970. Irrigation sales reached a maximum proportion of nearly 20 percent of company system sales in 1977. In 2003 the irrigation proportion of system sales was nearly 13 percent. By 2013 irrigation is projected to comprise about 11 percent of company system sales. The customer load proportions are shown in *figure 19* on page 29.

In 1970 Idaho Power had about 7,300 irrigation accounts. By 2003 the number of irrigation accounts had increased to 16,020, and there are projected to be nearly 18,793 irrigation accounts at the end of the planning period in 2013.

Since 1990, the Company has experienced a growth in the number of irrigation customers, but no growth in electricity sales (weather-adjusted). The number of customers has increased because customers are converting previously furrow-irrigated land to sprinkler-irrigated land. However, the conversion rate is low. Also, 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 is drawn from canals and not from deep ground-water wells.

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 Company's Large Power Service or Schedule 19 customers that consistently require over 1,000 kilowatts each billing period. There were about 50 industrial customers of Idaho Power in 1970 that comprised eight percent of the Company's system sales. By December 2003 the number of industrial customers had risen to 110, representing about 17 percent of system sales.

Industrial Load Growth

(average megawatts)

	2003	***2008***	***2013***	***Growth Rate (% Per Year) 2003-2013***
Expected Case	255	298	344	3.0

table 8

In the expected case forecast, industrial load grows from 255 average megawatts in 2003 to 344 average megawatts in 2013, an average annual growth rate of 3.0 percent (*table 8*). The industrial load 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 9*.

Forecasted Industrial Load

(average megawatts)

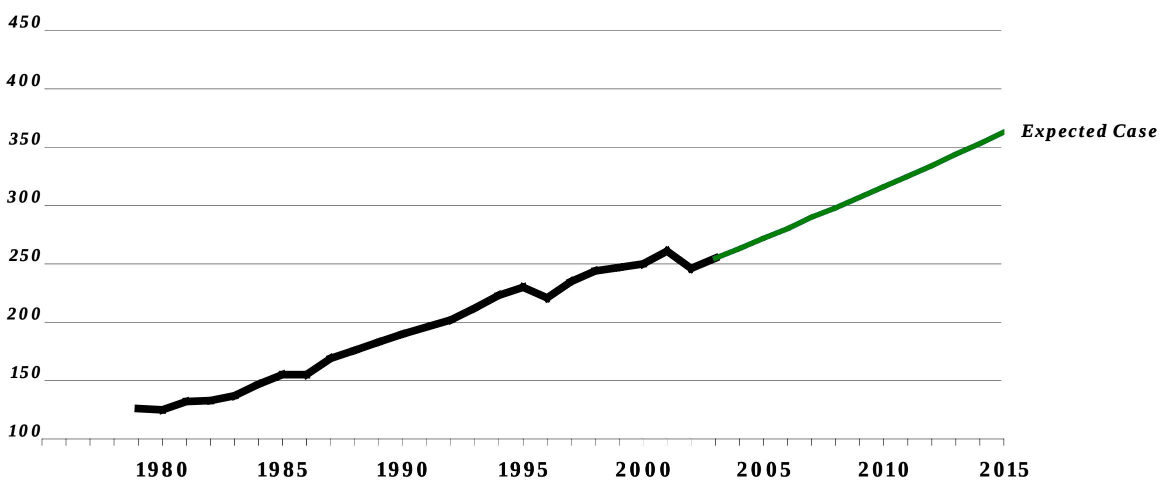


figure 9

The industrial energy forecast is based upon service area employment projections taken from the 2004 Economic Forecast. The Company's Schedule 19 customers were categorized and their historical electricity sales were summarized by economic activity.

The importance of each economic sector was determined by ranking each sectors electricity usage from largest to smallest. The appropriate employment series were then matched to each economic sector. A single driver was constructed by weighting the various employment series by the importance of each economic activity. The percentage change in the weighted employment driver was used to escalate electricity sales to the industrial customers over time.

The pie chart in figure 10 below illustrates the 2003 industrial electricity consumption by industry group. By far the largest share of electricity was consumed by the Food and Kindred Products sector (48 percent), followed by Stone, Clay, Glass, and Concrete Products (7 percent), Electronic and Other Electrical Equipment (6 percent), and Industrial and Commercial Machinery (6 percent). As the chart shows, several other industry groups make up the remaining share of the 2003 industrial electricity consumption.

Industrial Electricity Consumption by Industry Group

(based on 2003 figures)

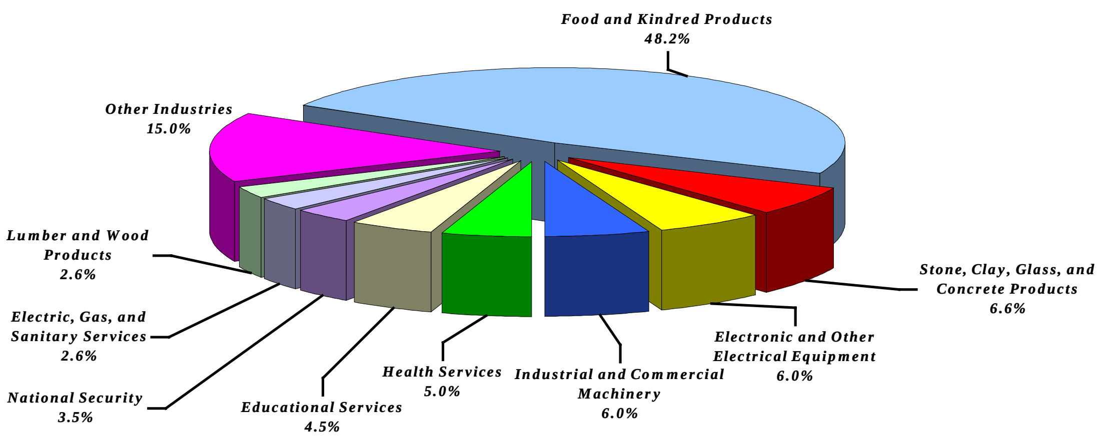


figure 10

Additional Firm Load

Special contracts exist for five large customers that are recognized as firm load customers. These customers are Micron Technology, Simplot Fertilizer, Idaho National Engineering and Environmental Laboratory (INEEL), the City of Weiser, and Raft River Rural Electric Cooperative, Inc. (Raft River). Together, these customers make up the additional firm load category.

Additional Firm Load Growth

(average megawatts)

	2003	***2008***	***2013***	***Growth Rate (% Per Year) 2003-2013***
Expected Case	128	142	155	2.0

table 9

In the expected case forecast, additional firm load is expected to increase from 128 average megawatts in 2003 to 155 average megawatts in the year 2013, an average growth rate of 2.0 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 11*.

Forecasted Additional Firm Load

(average megawatts)

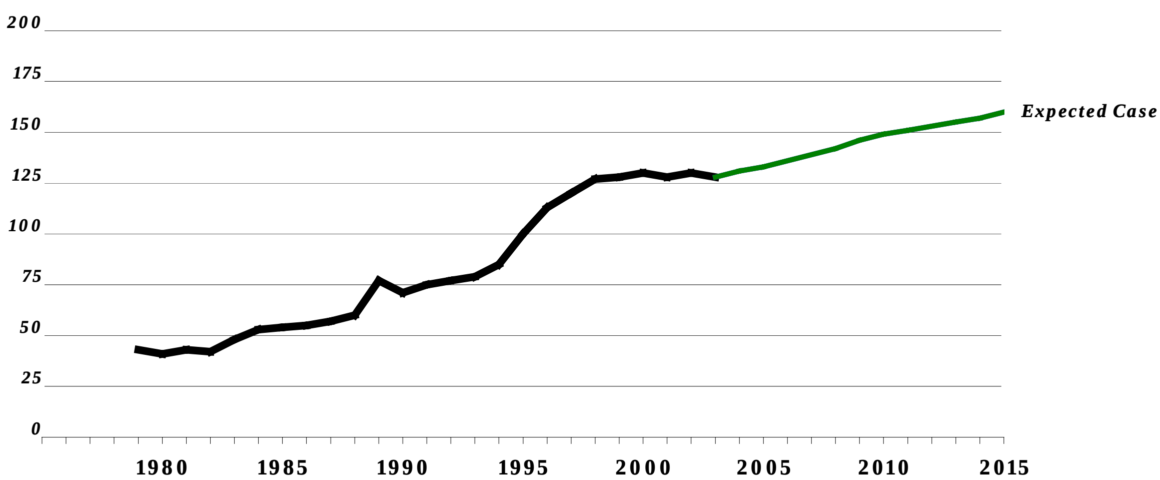


figure 11

Micron Technology is currently the Company's largest individual customer. In this forecast, electricity sales to Micron Technology are expected to steadily rise throughout the forecast period. The primary driver of long-term electricity sales growth at Micron Technology is employment growth in the Electronic Equipment sector as provided by the 2004 Economic Forecast. Micron's contract allows them to expand capacity up to 100 megawatts.

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western United States. In late August of 2002, Simplot Fertilizer closed its ammonia production facility. The ammonia plant represented about 11 MW or about one-third of the entire Simplot load. The ammonia is now being purchased on contract from an outside supplier. Offsetting the decline is the equipment required to unload and store the ammonia, which consists of an additional 3 or 4 MW. The future electricity usage at the plant is expected to continue to increase, although at a relatively slow rate of growth. Employment growth in the Chemical and Allied Products sector is the primary driver of long-term electricity sales growth at Simplot Fertilizer.

The Department of Energy provided an energy consumption and peak demand forecast through 2007 for the INEEL. The forecast calls for loads to remain flat throughout the forecast period. Looking back ten years ago, the annual loads at the INEEL were quite volatile due to operational constraints affecting the availability of their nuclear reactor to generate electricity. However, as of October 1994, the INEEL nuclear reactor no longer generates electricity and, consequently, the amount of electricity provided by Idaho Power increased considerably.

The City of Weiser is surrounded by and dependent upon the economic health of the Idaho Power service territory. Electricity sales to the City of Weiser are assumed to vary directly with household growth in Idaho's Washington County, in which the City of Weiser resides.

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 Company's former customers in the state of Nevada. Idaho Power Company 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. The closing date on the transaction was April 2, 2001. Raft River is also located entirely within Idaho Power Company's load control area.

Company Firm Load

Firm load is the sum of the individual loads of the residential, commercial, industrial, and irrigation customers, as well as special contracts (excluding Astaris), the City of Weiser, and Raft River. Firm load excludes not only Astaris, but also all contracts to provide firm energy to off-system customers. Without the dampening effects of Astaris and expiring off-system contracts on load growth, firm load more accurately portrays the underlying growth trend within the service territory than total load, which includes both Astaris and off-system commitments. The expiration of off-system contracts also explains why the firm load growth rates (*table 10*) are higher than the total load growth rates (*table 14*) over the planning period.

Firm Load Growth

(average megawatts)

	2003	***2008***	***2013***	***Growth Rate (% Per Year) 2003-2013***
90th Percentile	1740	1962	2171	2.2
70th Percentile	1672	1889	2094	2.3
Expected Case	1631	1846	2049	2.3

table 10

In the expected case forecast, total firm load is expected to increase from 1,631 average megawatts in 2003 reaching 2,049 average megawatts in the year 2013, an average growth rate of 2.3 percent per year over the planning period (*table 10*). In the 70th percentile forecast, total firm load is expected to increase from 1,672 average megawatts in 2003 reaching 2,094 average megawatts in the year 2013, an average growth rate of 2.3 percent per year over the planning period *(table 10)*. The three scenarios of projected firm load are illustrated in *figure 12*.

Forecasted Firm Load

(average megawatts)

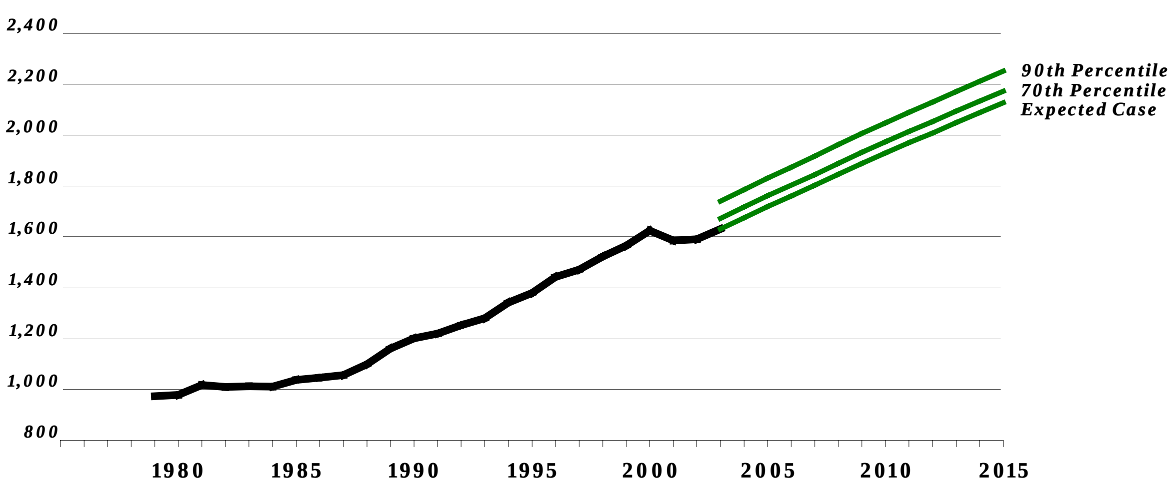


figure 12

Company Firm Peak

As defined here, firm peak load includes the sum of the individual coincident peak demands of the residential, commercial, industrial, and irrigation customers, as well as special contracts (excluding Astaris), the City of Weiser, and Raft River.

Firm Summer Peak Load Growth

(megawatts)

	2003	*2008*	*2013*	***Growth Rate (% Per Year) 2003-2013***
95th Percentile	2980	3389	3811	2.5
90th Percentile	2966	3374	3794	2.5
50th Percentile	2888	3285	3694	2.5

table 11

The all-time firm summer peak demand was 2,963 megawatts, recorded on July 12, 2002, at 4:00 p.m. One year later, on July 22, 2003, at 5:00 p.m., the firm peak reached 2,944 megawatts, nearly matching the record peak of the previous year. The summer firm peak load growth has accelerated over the past ten years as air-conditioning has become standard in nearly all new residential home construction and new commercial buildings. The 2001 summer peak was dampened by the nearly 30 percent cutback in irrigation load due to the 2001 voluntary load reduction program.

In the 90th percentile forecast, total firm summer peak load is expected to increase from 2,966 megawatts in 2003 reaching 3,794 megawatts in the year 2013, an average growth rate of 2.5 percent per year over the planning period (*table 11*).

Forecasted Firm Summer Peak

(megawatts)

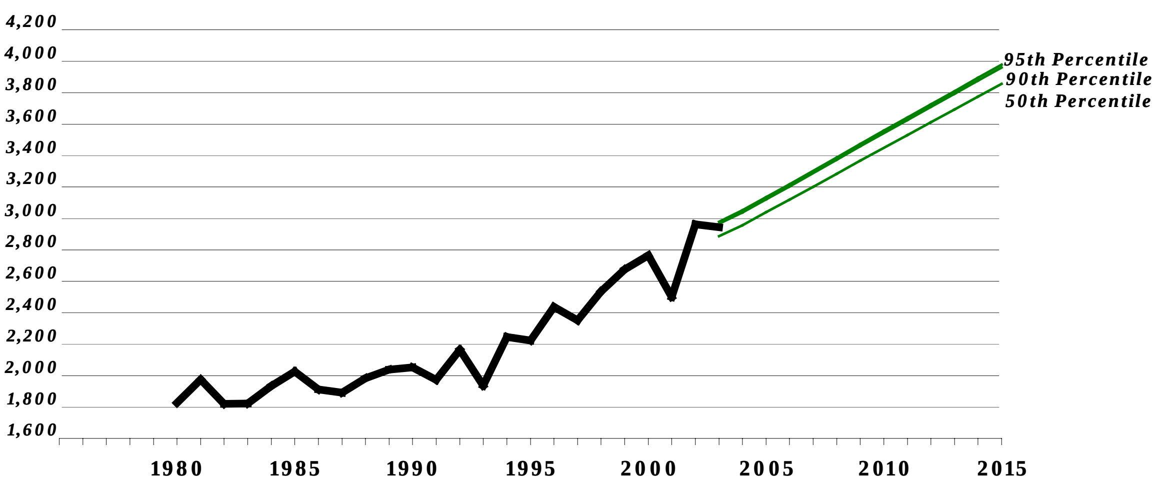


figure 13

In the 95h percentile forecast, total firm summer peak load is expected to increase from 2,980 megawatts in 2003 reaching 3,811 megawatts in the year 2013. The three scenarios of projected firm summer peak load are illustrated in *figure 13*.

The maximum firm winter peak demand was 2,342 megawatts reached in December 1998. Evident from the graph is the fact historical winter firm peak load is more variable than summer firm peak load. The range in temperatures in winter months is far greater than the range in temperatures in summer months. The wider spread of the winter forecast lines in *figure 14* illustrates the higher variability associated with winter temperatures.

Firm Winter Peak Load Growth

(megawatts)

	2003	*2008*	*2013*	*Growth Rate (% Per Year) 2003-2013*
95th Percentile	2469	2780	3059	2.2
90th Percentile	2397	2708	2987	2.2
50th Percentile	2211	2521	2801	2.4

table 12

In the 90th percentile forecast, total firm winter peak load is expected to increase from 2,397 megawatts in 2003 reaching 2,987 megawatts in the year 2013, an average growth rate of 2.2 percent per year over the planning period (*table 12*). In the 95th percentile forecast, total firm winter peak load is expected to increase from 2,469 megawatts in 2003 reaching 3,059 megawatts in the year 2013, an average growth rate of 2.2 percent per year over the planning period *(table 12)*. The three scenarios of projected firm winter peak load are illustrated in *figure 14*.

Forecasted Firm Winter Peak

(megawatts)

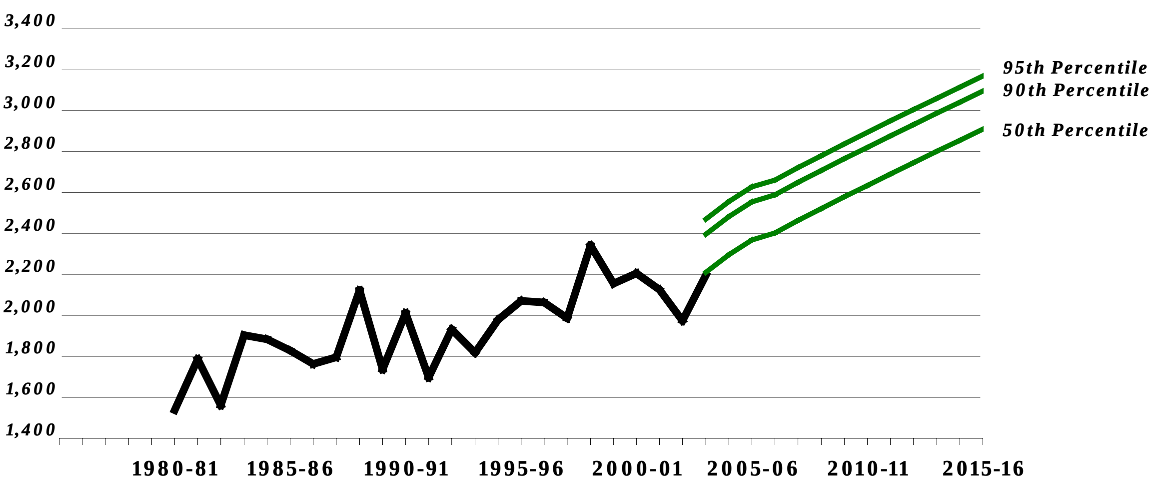


figure 14

Astaris Load

The Astaris elemental phosphorous plant, located on the western edge of Pocatello, Idaho, ceased large-scale production in mid-December of 2001. Four months later, in April 2002, the special contract between Astaris and Idaho Power Company was terminated. Since then Astaris (now FMC Corporation) has been billed for electric service as a Schedule 19 (see Industrial discussion). Therefore, Astaris load since May 1, 2002, as a special contract customer are zero. Astaris had been the Company's largest individual customer and in some past years had averaged nearly 200 average megawatts. The historical average annual load at Astaris is presented in figure 15.

Historical Astaris (FMC) Load

(average megawatts)

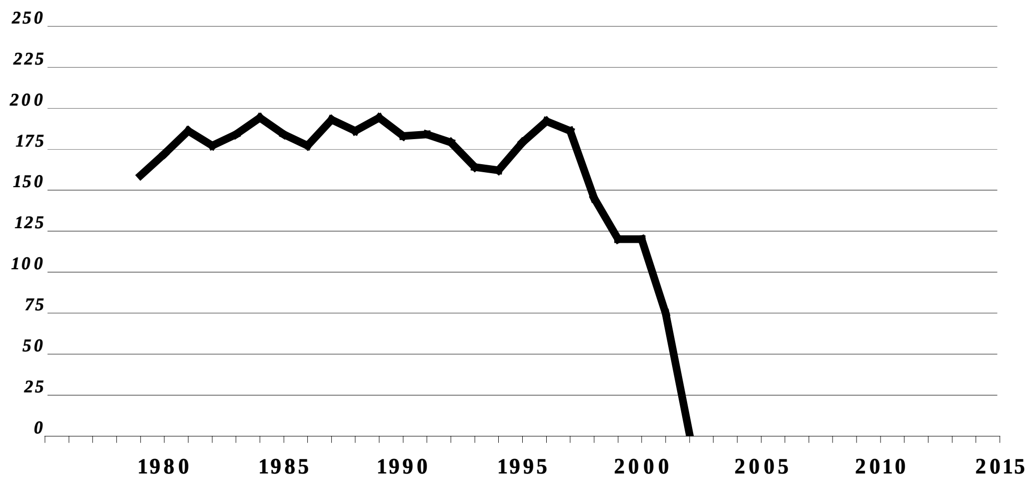


figure 15

Company System Load

System Load Growth

(average megawatts)

	2003	2008	2013	Growth Rate (% Per Year) 2003-2013
90th Percentile	1740	1962	2171	2.2
70th Percentile	1672	1889	2094	2.3
Expected Case	1631	1846	2049	2.3

table 13

System load is made up of firm load plus Astaris load, but excludes long-term off-system contracts. The expected case system load forecast is based upon an economic forecast for the service territory and represents Idaho Power's most probable load growth during the planning period. The expected case forecast system load growth rate averages 2.3 percent per year over the 2003 to 2013 time period. Company system load projections are reported in *table 13* and pictured in *figure 16*.

In the expected case forecast, Company system load is expected to increase from 1,631 average megawatts in 2003 reaching 2,049 average megawatts in the year 2013. In the 70th percentile forecast, Company system load is expected to increase from 1,672 average megawatts in 2003 reaching 2,094 average megawatts in the year 2013, an average growth rate of 2.3 percent per year over the planning period *(table 13)*.

Forecasted System Load

(average megawatts)

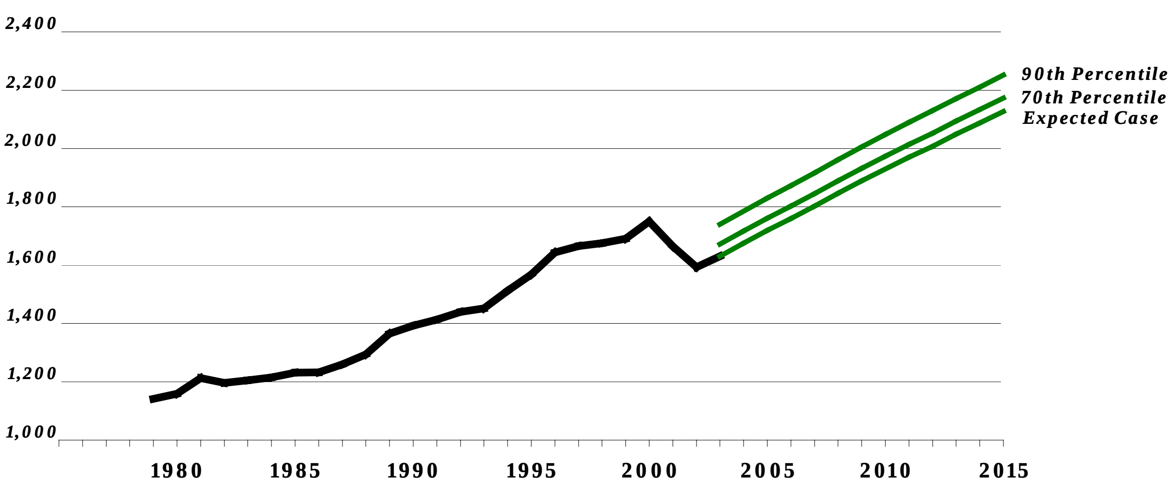


figure 16

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 with duration greater than one year and effective during the forecast period. At this time, only one long-term contract remains and that is with the city of Colton, California. The Colton contract is scheduled to expire during the forecast period causing negative annual growth.

In this forecast, sales to Colton, California, are assumed to continue through May of 2005. Long-term contracts with Washington City and Utah Associated Municipal Power Systems (UAMPS) expired in June 2002 and December 2003, respectively, and have not been renewed.

As illustrated in *figure 17*, the historical consumption for the contract off-system load category was considerable in the early 1990s, however, after 1995 off-system loads begin to decline through 2004. As intended, the off-system contracts and their corresponding energy requirements expired as the Company's current projections of surplus energy diminish due to retail load growth.

Forecasted Contract Off-System Load by Customer

(average megawatts)

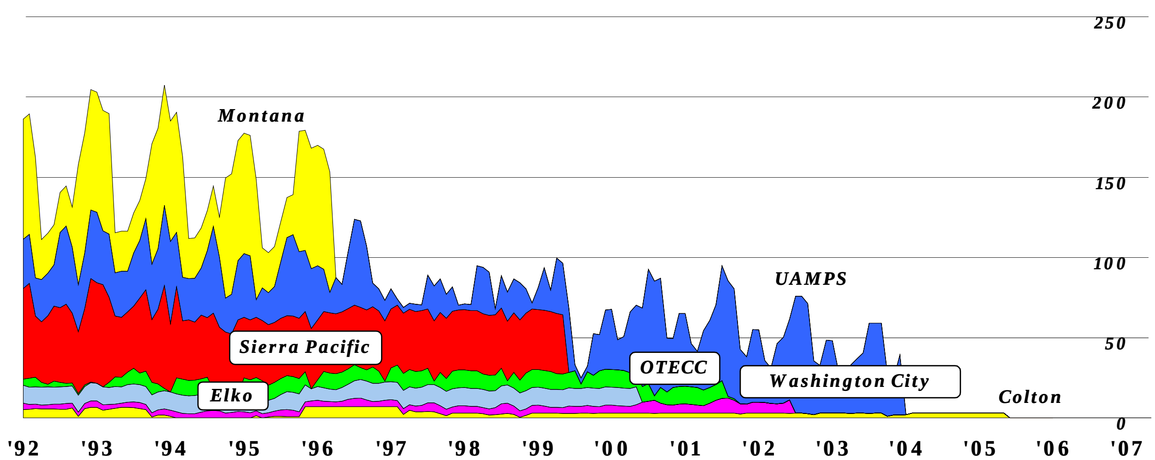


figure 17

Total Company Load

Total Company Load Growth

(average megawatts)

	2003	2008	2013	Growth Rate (% Per Year) 2003-2013
90th Percentile	1781	1962	2171	2.0
70th Percentile	1713	1889	2094	2.0
Expected Case	1672	1846	2049	2.0

table 14

Accompanied by an outlook of moderate economic growth for the Idaho Power service territory throughout the forecast period, the 2004 Sales and Load Forecast projects continued growth in the Company's total load. Total load is made up of system load plus long-term off-system contracts. Total company load projections are listed in *table 14* and illustrated in *figure 18*. The expected case scenario average growth rate of 2.0 percent per year represents the most probable outlook expected by the Company. Even though Idaho Power's system load is expected to increase at a 2.3 percent average annual compound growth rate, the expiration of the UAMPS contract in December 2003 and the Colton contract during the forecast period reduces Idaho Power's total load growth rate to a 2.0 percent average annual compound growth rate. In the 70th percentile forecast, Company total load is expected to increase from 1,713 average megawatts in 2003 and reach 2,094 average megawatts in the year 2013.

Forecasted Total Load

(average megawatts)

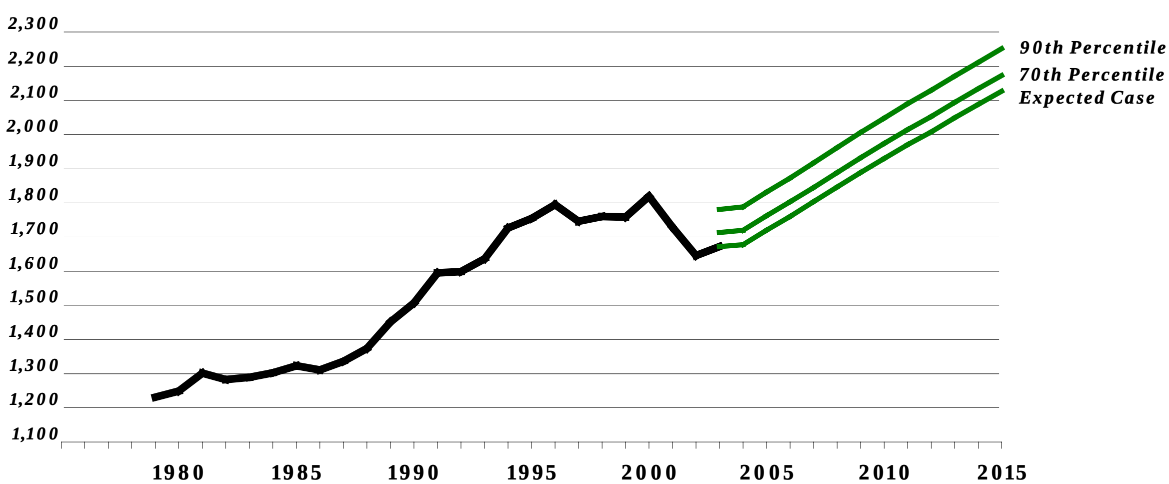


figure 18

The composition of total company electricity sales by year is shown in *figure 19*. Residential sales are forecast to be over 20 percent higher in 2013 gaining nearly 0.9 million MWh over 2003. Commercial sales are expected to be nearly 40 percent higher or nearly 1.4 million MWh above 2003 followed by industrial (35 percent higher or nearly 0.8 million additional MWh) and irrigation (only 5 percent higher in 2013). Electricity sales to Astaris, as a special contract customer, ended in April 2002. The one remaining long-term contract with Colton, California, to provide firm energy off-system will expire as of May 2005.

Composition of Electricity Sales

(000's of MWh)

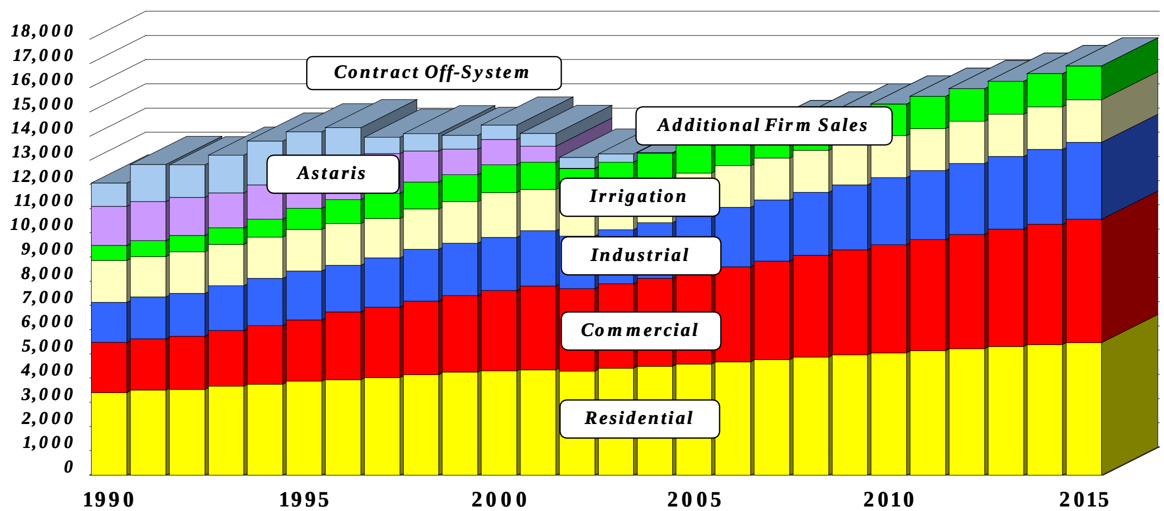


figure 19

The additional firm sales category (which represents sales to Micron Technology, Simplot Fertilizer, INEEL, City of Weiser, and Raft River) is forecast to grow by nearly 22 percent over the 2003 through 2013 time period.

Appendix A

Appendix A. Historical and Projected Sales and Load

Residential Load

Historical Residential Sales and Load, 1970-2003

(weather adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (000s of MWh)	Percent Change	Average Load (megawatts)	Percent Change
1970	132,135		9,982	1,319		152	
1971	138,071	4.5%	10,537	1,455	10.3%	167	10.1%
1972	145,208	5.2%	10,959	1,591	9.4%	184	9.8%
1973	152,957	5.3%	11,527	1,763	10.8%	203	10.3%
1974	160,151	4.7%	12,070	1,933	9.6%	223	10.2%
1975	167,622	4.7%	12,941	2,169	12.2%	250	11.9%
1976	175,720	4.8%	13,471	2,367	9.1%	271	8.6%
1977	184,561	5.0%	13,688	2,526	6.7%	290	6.9%
1978	194,650	5.5%	14,310	2,785	10.3%	322	10.9%
1979	202,982	4.3%	14,786	3,001	7.7%	343	6.5%
1980	209,629	3.3%	14,652	3,071	2.3%	350	2.1%
1981	213,579	1.9%	14,399	3,075	0.1%	350	0.1%
1982	216,696	1.5%	14,429	3,127	1.7%	357	2.0%
1983	219,849	1.5%	14,366	3,158	1.0%	362	1.5%
1984	222,695	1.3%	14,152	3,152	-0.2%	357	-1.6%
1985	225,185	1.1%	14,082	3,171	0.6%	363	1.6%
1986	227,081	0.8%	14,172	3,218	1.5%	368	1.4%
1987	228,868	0.8%	14,103	3,228	0.3%	367	-0.3%
1988	230,771	0.8%	14,350	3,312	2.6%	377	2.9%
1989	233,370	1.1%	14,391	3,358	1.4%	385	2.1%
1990	238,117	2.0%	14,338	3,414	1.7%	393	2.0%
1991	243,207	2.1%	14,474	3,520	3.1%	402	2.2%
1992	249,767	2.7%	14,167	3,538	0.5%	408	1.5%
1993	258,271	3.4%	14,221	3,673	3.8%	415	1.8%
1994	267,854	3.7%	14,005	3,751	2.1%	434	4.6%
1995	277,131	3.5%	14,008	3,882	3.5%	439	1.0%
1996	286,227	3.3%	13,771	3,942	1.5%	457	4.1%
1997	294,674	3.0%	13,689	4,034	2.3%	463	1.4%
1998	303,300	2.9%	13,677	4,148	2.8%	473	2.2%
1999	312,901	3.2%	13,584	4,251	2.5%	487	2.9%
2000	322,402	3.0%	13,378	4,313	1.5%	499	2.5%
2001	331,009	2.7%	13,133	4,347	0.8%	475	-4.9%
2002	339,764	2.6%	12,629	4,291	-1.3%	489	2.9%
2003	349,219	2.8%	12,635	4,412	2.8%	506	3.6%

table 15

Residential Load

Projected Residential Sales and Load, 2004-2015

Year	*Customers*	*Percent Change*	*kWh per Customer*	*Billed Sales (000s of MWh)*	*Percent Change*	*Average Load (megawatts)*	*Percent Change*
2004	357,467	2.4%	12,525	4,477	1.5%	513	1.3%
2005	365,400	2.2%	12,541	4,583	2.4%	524	2.1%
2006	373,593	2.2%	12,519	4,677	2.1%	535	2.1%
2007	382,030	2.3%	12,482	4,769	2.0%	545	2.0%
2008	390,622	2.2%	12,472	4,872	2.2%	557	2.2%
2009	398,661	2.1%	12,462	4,968	2.0%	568	1.9%
2010	406,053	1.9%	12,448	5,055	1.7%	578	1.7%
2011	413,227	1.8%	12,439	5,140	1.7%	587	1.7%
2012	420,467	1.8%	12,424	5,224	1.6%	597	1.7%
2013	427,885	1.8%	12,410	5,310	1.6%	607	1.6%
2014	434,980	1.7%	12,393	5,391	1.5%	616	1.5%
2015	442,013	1.6%	12,373	5,469	1.5%	625	1.5%

table 16

Commercial Load

Historical Commercial Sales and Load, 1970-2003

(weather adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (000s of MWh)	Percent Change	Average Load (megawatts)	Percent Change
1970	21,375		42,769	914		105	
1971	22,077	3.3%	45,386	1,002	9.6%	115	9.1%
1972	22,585	2.3%	46,140	1,042	4.0%	120	4.3%
1973	23,286	3.1%	48,140	1,121	7.6%	128	7.3%
1974	24,096	3.5%	49,025	1,181	5.4%	136	5.8%
1975	25,045	3.9%	51,213	1,283	8.6%	147	8.3%
1976	26,034	3.9%	52,507	1,367	6.6%	157	6.6%
1977	27,112	4.1%	52,410	1,421	3.9%	162	3.4%
1978	27,831	2.7%	52,474	1,460	2.8%	169	4.3%
1979	28,087	0.9%	56,389	1,584	8.4%	180	6.4%
1980	28,797	2.5%	54,136	1,559	-1.6%	178	-1.0%
1981	29,567	2.7%	54,282	1,605	3.0%	184	3.3%
1982	30,167	2.0%	54,123	1,633	1.7%	186	1.3%
1983	30,776	2.0%	52,589	1,618	-0.9%	186	-0.2%
1984	31,554	2.5%	53,054	1,674	3.4%	190	2.3%
1985	32,417	2.7%	53,634	1,739	3.9%	199	4.5%
1986	33,208	2.4%	53,292	1,770	1.8%	202	1.8%
1987	33,975	2.3%	52,856	1,796	1.5%	204	0.9%
1988	34,723	2.2%	54,186	1,882	4.8%	215	5.1%
1989	35,638	2.6%	55,245	1,969	4.6%	226	5.4%
1990	36,785	3.2%	56,172	2,066	4.9%	237	4.7%
1991	37,922	3.1%	55,813	2,117	2.4%	243	2.5%
1992	39,022	2.9%	56,337	2,198	3.9%	253	4.2%
1993	40,047	2.6%	57,461	2,301	4.7%	261	3.2%
1994	41,629	4.0%	58,264	2,425	5.4%	280	7.4%
1995	43,165	3.7%	58,620	2,530	4.3%	288	2.8%
1996	44,995	4.2%	62,063	2,793	10.4%	323	12.1%
1997	46,819	4.1%	62,012	2,903	4.0%	333	3.2%
1998	48,404	3.4%	62,847	3,042	4.8%	348	4.5%
1999	49,430	2.1%	64,054	3,166	4.1%	363	4.3%
2000	50,117	1.4%	66,163	3,316	4.7%	384	5.8%
2001	51,501	2.8%	67,286	3,465	4.5%	382	-0.3%
2002	52,915	2.7%	64,648	3,421	-1.3%	390	2.0%
2003	54,194	2.4%	64,428	3,492	2.1%	400	2.6%

table 17

Commercial Load

Projected Commercial Sales and Load, 2004-2015

Year	*Customers*	*Percent Change*	*kWh per Customer*	*Billed Sales (000s of MWh)*	*Percent Change*	*Average Load (megawatts)*	*Percent Change*
2004	55,653	2.7%	65,444	3,642	4.3%	417	4.3%
2005	57,119	2.6%	66,534	3,800	4.3%	435	4.1%
2006	58,576	2.6%	67,157	3,934	3.5%	450	3.5%
2007	60,069	2.5%	67,715	4,068	3.4%	465	3.4%
2008	61,583	2.5%	68,302	4,206	3.4%	481	3.4%
2009	63,018	2.3%	68,866	4,340	3.2%	496	3.2%
2010	64,363	2.1%	69,408	4,467	2.9%	511	2.9%
2011	65,678	2.0%	69,948	4,594	2.8%	525	2.8%
2012	67,002	2.0%	70,460	4,721	2.8%	540	2.8%
2013	68,350	2.0%	70,953	4,850	2.7%	554	2.7%
2014	69,656	1.9%	71,436	4,976	2.6%	569	2.6%
2015	70,956	1.9%	71,917	5,103	2.6%	583	2.6%

table 18

Irrigation Load

Historical Irrigation Sales and Load, 1970-2003

(weather adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (000s of MWh)	Percent Change	Average Load (megawatts)	Percent Change
1970	7,319		117,868	863		98	
1971	7,518	2.7%	134,026	1,008	16.8%	115	16.8%
1972	7,815	4.0%	124,924	976	-3.1%	111	-3.4%
1973	8,341	6.7%	134,174	1,119	14.6%	128	15.0%
1974	8,971	7.6%	142,618	1,279	14.3%	146	14.3%
1975	9,480	5.7%	154,038	1,460	14.1%	167	14.1%
1976	9,936	4.8%	152,873	1,519	4.0%	173	3.8%
1977	10,238	3.0%	154,284	1,580	4.0%	180	4.3%
1978	10,476	2.3%	146,493	1,535	-2.8%	176	-2.3%
1979	10,711	2.2%	156,417	1,675	9.2%	190	8.0%
1980	10,854	1.3%	154,019	1,672	-0.2%	190	0.0%
1981	11,248	3.6%	164,547	1,851	10.7%	211	10.8%
1982	11,312	0.6%	151,076	1,709	-7.7%	195	-7.4%
1983	11,133	-1.6%	143,379	1,596	-6.6%	182	-6.7%
1984	11,375	2.2%	130,672	1,486	-6.9%	169	-7.2%
1985	11,576	1.8%	127,751	1,479	-0.5%	169	-0.2%
1986	11,308	-2.3%	129,567	1,465	-0.9%	167	-0.9%
1987	11,254	-0.5%	125,311	1,410	-3.7%	161	-3.7%
1988	11,378	1.1%	128,786	1,465	3.9%	167	3.6%
1989	11,957	5.1%	133,471	1,596	8.9%	182	9.2%
1990	12,340	3.2%	139,925	1,727	8.2%	197	8.2%
1991	12,484	1.2%	134,100	1,674	-3.0%	191	-3.1%
1992	12,809	2.6%	133,950	1,716	2.5%	195	2.2%
1993	13,078	2.1%	130,080	1,701	-0.8%	194	-0.6%
1994	13,559	3.7%	125,900	1,707	0.3%	195	0.4%
1995	13,679	0.9%	125,400	1,715	0.5%	196	0.5%
1996	14,074	2.9%	122,235	1,720	0.3%	196	0.0%
1997	14,383	2.2%	112,803	1,622	-5.7%	185	-5.4%
1998	14,695	2.2%	113,273	1,665	2.6%	190	2.6%
1999	14,912	1.5%	115,262	1,719	3.3%	196	3.3%
2000	15,253	2.3%	121,481	1,853	7.8%	211	7.4%
2001	15,522	1.8%	109,834	1,705	-8.0%	195	-7.8%
2002	15,840	2.0%	104,668	1,658	-2.8%	189	-2.7%
2003	16,020	1.1%	104,034	1,667	0.5%	190	0.5%

table 19

Irrigation Load

Projected Irrigation Sales and Load, 2004-2015

Year	*Customers*	*Percent Change*	*kWh per Customer*	*Billed Sales (000s of MWh)*	*Percent Change*	*Average Load (megawatts)*	*Percent Change*
2004	16,434	2.6%	104,421	1,716	3.0%	195	2.7%
2005	16,729	1.8%	103,022	1,723	0.4%	197	0.7%
2006	17,026	1.8%	101,058	1,721	-0.2%	196	-0.2%
2007	17,323	1.7%	99,591	1,725	0.3%	197	0.3%
2008	17,618	1.7%	98,144	1,729	0.2%	197	0.0%
2009	17,913	1.7%	96,745	1,733	0.2%	198	0.5%
2010	18,209	1.7%	95,383	1,737	0.2%	198	0.2%
2011	18,506	1.6%	94,077	1,741	0.2%	199	0.2%
2012	18,801	1.6%	92,815	1,745	0.2%	199	0.0%
2013	19,095	1.6%	91,597	1,749	0.2%	200	0.5%
2014	19,393	1.6%	90,391	1,753	0.2%	200	0.2%
2015	19,690	1.5%	89,223	1,757	0.2%	201	0.2%

table 20

Industrial Load

Historical Industrial Sales and Load, 1970-2003

Year	Customers	Percent Change	kWh per Customer	Billed Sales (000s of MWh)	Percent Change	Average Load (megawatts)	Percent Change
1970	49		9,173,784	445		51	
1971	50	3.3%	10,474,941	525	17.9%	60	17.2%
1972	56	12.1%	10,944,714	615	17.2%	71	17.3%
1973	63	12.3%	10,889,056	687	11.7%	79	11.4%
1974	65	2.2%	11,464,249	739	7.6%	84	6.9%
1975	71	10.5%	11,014,121	785	6.1%	90	7.3%
1976	73	3.0%	11,681,540	858	9.3%	99	9.0%
1977	85	15.1%	10,988,826	929	8.3%	106	7.4%
1978	99	17.6%	9,786,753	972	4.7%	111	4.8%
1979	109	9.6%	9,989,158	1,087	11.8%	126	13.3%
1980	112	2.7%	9,894,706	1,106	1.7%	125	-0.4%
1981	118	5.7%	9,718,723	1,148	3.9%	132	5.5%
1982	122	3.5%	9,504,283	1,162	1.2%	133	0.5%
1983	122	-0.3%	9,797,522	1,194	2.7%	137	3.4%
1984	124	1.5%	10,369,789	1,282	7.4%	147	7.1%
1985	125	1.2%	10,844,888	1,357	5.9%	155	5.7%
1986	129	2.7%	10,550,145	1,357	-0.1%	155	-0.3%
1987	134	4.1%	11,006,455	1,474	8.7%	169	9.0%
1988	133	-1.0%	11,660,183	1,546	4.9%	176	4.6%
1989	132	-0.6%	12,091,482	1,594	3.1%	183	3.5%
1990	132	0.2%	12,584,200	1,662	4.3%	190	4.3%
1991	135	2.5%	12,699,665	1,719	3.4%	196	2.9%
1992	140	3.4%	12,650,945	1,770	3.0%	202	3.3%
1993	141	0.5%	13,179,585	1,854	4.7%	212	4.9%
1994	143	1.7%	13,616,608	1,948	5.1%	223	5.1%
1995	120	-15.9%	16,793,437	2,021	3.7%	230	3.1%
1996	103	-14.4%	18,774,093	1,934	-4.3%	221	-4.1%
1997	106	2.7%	19,309,504	2,042	5.6%	235	6.3%
1998	111	4.6%	19,378,734	2,145	5.0%	244	4.2%
1999	108	-2.3%	19,985,029	2,160	0.7%	247	1.0%
2000	107	-0.8%	20,433,299	2,191	1.5%	250	1.3%
2001	111	3.5%	20,618,361	2,289	4.4%	261	4.2%
2002	111	-0.1%	19,441,876	2,156	-5.8%	246	-5.5%
2003	112	1.0%	19,950,866	2,234	3.6%	255	3.7%

table 21

Industrial Load

Projected Industrial Sales and Load, 2004-2015

Year	Customers	Percent Change	kWh per Customer	Billed Sales (000s of MWh)	Percent Change	Average Load (megawatts)	Percent Change
2004	114	1.5%	20,198,080	2,296	2.7%	263	3.1%
2005	116	2.1%	20,465,291	2,374	3.4%	272	3.2%
2006	118	1.7%	20,783,739	2,452	3.3%	280	3.3%
2007	119	0.8%	21,288,653	2,533	3.3%	290	3.3%
2008	121	1.7%	21,561,643	2,609	3.0%	298	3.0%
2009	122	0.8%	21,999,442	2,684	2.9%	307	2.9%
2010	124	1.6%	22,298,462	2,765	3.0%	316	3.0%
2011	125	0.8%	22,766,760	2,846	2.9%	325	2.9%
2012	126	0.8%	23,213,111	2,925	2.8%	334	2.8%
2013	128	1.6%	23,477,579	3,005	2.7%	344	2.8%
2014	131	2.3%	23,576,332	3,088	2.8%	353	2.8%
2015	131	0.0%	24,208,060	3,171	2.7%	363	2.7%

table 22

Additional Firm Sales and Load

(includes Micron Technology, Simplot Fertilizer, INEEL, City of Weiser, and Raft River Rural Electric Cooperative, Inc.)

Additional Firm Sales and Load - Historical Data, 1970-2003

Year	Billed Sales (000s of MWh)	Percent Change	Average Load (megawatts)	Percent Change
1970	318		36	
1971	294	-7.6%	34	-7.6%
1972	284	-3.5%	32	-3.8%
1973	290	2.2%	33	2.5%
1974	282	-2.8%	32	-2.8%
1975	314	11.2%	36	11.2%
1976	277	-11.8%	32	-12.1%
1977	311	12.4%	36	12.7%
1978	357	14.7%	41	14.7%
1979	373	4.7%	43	4.7%
1980	360	-3.7%	41	-3.9%
1981	376	4.5%	43	4.8%
1982	368	-2.2%	42	-2.2%
1983	425	15.5%	48	15.5%
1984	467	9.9%	53	9.6%
1985	473	1.4%	54	1.6%
1986	482	1.9%	55	1.9%
1987	503	4.3%	57	4.3%
1988	531	5.6%	60	5.3%
1989	671	26.5%	77	26.9%
1990	625	-6.9%	71	-6.9%
1991	661	5.7%	75	5.7%
1992	680	2.9%	77	2.6%
1993	689	1.3%	79	1.6%
1994	741	7.4%	85	7.4%
1995	877	18.4%	100	18.4%
1996	988	12.6%	113	12.3%
1997	1,048	6.0%	120	6.3%
1998	1,112	6.2%	127	6.2%
1999	1,121	0.8%	128	0.8%
2000	1,143	1.9%	130	1.7%
2001	1,118	-2.1%	128	-1.9%
2002	1,139	1.9%	130	1.9%
2003	1,120	-1.7%	128	-1.7%

table 23

Additional Firm Sales and Load

(includes Micron Technology, Simplot Fertilizer, INEEL, City of Weiser, and Raft River Rural Electric Cooperative, Inc.)

Additional Firm Sales and Load - Projections, 2004-2015

Year	Billed Sales (000s of MWh)	Percent Change	Average Load (megawatts)	Percent Change
2004	1,152	2.8%	131	2.6%
2005	1,168	1.4%	133	1.7%
2006	1,194	2.3%	136	2.3%
2007	1,220	2.2%	139	2.2%
2008	1,249	2.4%	142	2.1%
2009	1,275	2.1%	146	2.3%
2010	1,304	2.3%	149	2.3%
2011	1,326	1.7%	151	1.7%
2012	1,346	1.5%	153	1.2%
2013	1,361	1.1%	155	1.4%
2014	1,380	1.4%	157	1.4%
2015	1,398	1.4%	160	1.4%

table 24

Company Firm Load

Historical Company Firm Sales and Load, 1970-2003

(weather adjusted)

Year	Billed Sales (000s of MWh)	Percent Change	Average Load (megawatts)	Percent Change
1970	3,859		489	
1971	4,284	11.0%	542	10.8%
1972	4,508	5.3%	572	5.4%
1973	4,981	10.5%	631	10.3%
1974	5,415	8.7%	687	9.0%
1975	6,011	11.0%	763	11.0%
1976	6,388	6.3%	809	6.0%
1977	6,766	5.9%	856	5.8%
1978	7,109	5.1%	905	5.8%
1979	7,721	8.6%	974	7.6%
1980	7,767	0.6%	978	0.4%
1981	8,056	3.7%	1,017	4.0%
1982	7,998	-0.7%	1,010	-0.7%
1983	7,991	-0.1%	1,012	0.3%
1984	8,061	0.9%	1,011	-0.1%
1985	8,219	2.0%	1,037	2.5%
1986	8,292	0.9%	1,046	0.8%
1987	8,410	1.4%	1,057	1.1%
1988	8,735	3.9%	1,099	3.9%
1989	9,189	5.2%	1,161	5.7%
1990	9,495	3.3%	1,201	3.4%
1991	9,691	2.1%	1,220	1.6%
1992	9,903	2.2%	1,252	2.6%
1993	10,219	3.2%	1,280	2.2%
1994	10,573	3.5%	1,342	4.8%
1995	11,026	4.3%	1,380	2.9%
1996	11,376	3.2%	1,442	4.5%
1997	11,649	2.4%	1,471	2.0%
1998	12,112	4.0%	1,523	3.5%
1999	12,417	2.5%	1,565	2.8%
2000	12,816	3.2%	1,624	3.8%
2001	12,924	0.8%	1,586	-2.3%
2002	12,665	-2.0%	1,591	0.3%
2003	12,925	2.0%	1,630	2.4%

table 25

Company Firm Load

Projected Company Firm Sales and Load, 2004-2015

Year	Billed Sales (000s of MWh)	Percent Change	Average Load (megawatts)	Percent Change
2004	13,283	2.8%	1,675	2.7%
2005	13,648	2.8%	1,719	2.6%
2006	13,978	2.4%	1,760	2.4%
2007	14,315	2.4%	1,803	2.4%
2008	14,666	2.4%	1,846	2.4%
2009	15,000	2.3%	1,889	2.3%
2010	15,328	2.2%	1,930	2.2%
2011	15,647	2.1%	1,970	2.1%
2012	15,961	2.0%	2,008	2.0%
2013	16,274	2.0%	2,049	2.0%
2014	16,587	1.9%	2,088	1.9%
2015	16,898	1.9%	2,127	1.9%

table 26

Astaris Load

Historical Astaris Sales and Load, 1970-2003

Year	Billed Sales (000s of MWh)	Percent Change	Average Load (megawatts)	Percent Change
1970	1,657		189	
1971	1,508	-9.0%	172	-9.0%
1972	1,819	20.6%	207	20.3%
1973	1,645	-9.6%	188	-9.3%
1974	1,643	-0.1%	188	-0.1%
1975	1,557	-5.3%	178	-5.3%
1976	1,575	1.2%	179	0.9%
1977	1,418	-10.0%	162	-9.7%
1978	1,542	8.8%	176	8.8%
1979	1,395	-9.6%	159	-9.6%
1980	1,513	8.5%	172	8.2%
1981	1,634	8.0%	186	8.3%
1982	1,554	-4.9%	177	-4.9%
1983	1,610	3.6%	184	3.6%
1984	1,701	5.7%	194	5.4%
1985	1,614	-5.1%	184	-4.9%
1986	1,554	-3.7%	177	-3.7%
1987	1,692	8.9%	193	8.9%
1988	1,635	-3.4%	186	-3.6%
1989	1,703	4.2%	194	4.5%
1990	1,604	-5.8%	183	-5.8%
1991	1,609	0.3%	184	0.3%
1992	1,570	-2.4%	179	-2.7%
1993	1,437	-8.4%	164	-8.2%
1994	1,420	-1.2%	162	-1.2%
1995	1,567	10.4%	179	10.4%
1996	1,689	7.8%	192	7.5%
1997	1,628	-3.6%	186	-3.4%
1998	1,273	-21.8%	145	-21.8%
1999	1,051	-17.4%	120	-17.4%
2000	1,490	41.7%	170	41.4%
2001	684	-54.1%	78	-54.0%
2002	11	-98.3%	1	-98.3%
2003	0	-100.0%	0	-100.0%

table 27

Astaris Load

Projected Astaris Sales and Load, 2004

Year	*Billed Sales (000s of MWh)*	*Percent Change*	*Average Load (megawatts)*	*Percent Change*
2004	0	0.0%	0	0.0%

table 28

Company System Load

Historical Company System Sales and Load, 1970-2003

(weather adjusted)

Year	Billed Sales (000s of MWh)	Percent Change	Average Load (megawatts)	Percent Change
1970	5,517		688	
1971	5,792	5.0%	723	5.1%
1972	6,328	9.3%	789	9.1%
1973	6,626	4.7%	828	4.9%
1974	7,059	6.5%	884	6.8%
1975	7,568	7.2%	949	7.4%
1976	7,963	5.2%	997	5.0%
1977	8,184	2.8%	1,026	2.9%
1978	8,652	5.7%	1,090	6.3%
1979	9,115	5.4%	1,141	4.7%
1980	9,280	1.8%	1,159	1.5%
1981	9,689	4.4%	1,213	4.7%
1982	9,552	-1.4%	1,196	-1.4%
1983	9,601	0.5%	1,205	0.8%
1984	9,762	1.7%	1,215	0.8%
1985	9,833	0.7%	1,231	1.3%
1986	9,845	0.1%	1,232	0.1%
1987	10,102	2.6%	1,260	2.3%
1988	10,370	2.7%	1,294	2.7%
1989	10,892	5.0%	1,365	5.5%
1990	11,099	1.9%	1,393	2.1%
1991	11,299	1.8%	1,413	1.4%
1992	11,473	1.5%	1,440	1.9%
1993	11,656	1.6%	1,452	0.9%
1994	11,993	2.9%	1,512	4.1%
1995	12,593	5.0%	1,568	3.7%
1996	13,065	3.7%	1,644	4.9%
1997	13,277	1.6%	1,666	1.4%
1998	13,385	0.8%	1,675	0.6%
1999	13,468	0.6%	1,691	0.9%
2000	14,306	6.2%	1,802	6.6%
2001	13,608	-4.9%	1,668	-7.4%
2002	12,677	-6.8%	1,593	-4.5%
2003	12,925	2.0%	1,630	2.4%

table 29

Company System Load

Projected Company System Sales and Load, 2004-2015

Year	Billed Sales (000s of MWh)	Percent Change	Average Load (megawatts)	Percent Change
2004	13,283	2.8%	1,675	2.7%
2005	13,648	2.8%	1,719	2.6%
2006	13,978	2.4%	1,760	2.4%
2007	14,315	2.4%	1,803	2.4%
2008	14,666	2.4%	1,846	2.4%
2009	15,000	2.3%	1,889	2.3%
2010	15,328	2.2%	1,930	2.2%
2011	15,647	2.1%	1,970	2.1%
2012	15,961	2.0%	2,008	2.0%
2013	16,274	2.0%	2,049	2.0%
2014	16,587	1.9%	2,088	1.9%
2015	16,898	1.9%	2,127	1.9%

table 30

Contract Off-System Load

Historical Contract Off-System Sales and Load, 1970-2003

Year	Billed Sales (000s of MWh)	Percent Change	Average Load (megawatts)	Percent Change
1970	386		44	
1971	439	13.6%	50	13.6%
1972	448	2.0%	51	1.7%
1973	489	9.3%	56	9.6%
1974	501	2.3%	57	2.3%
1975	568	13.5%	65	13.5%
1976	613	7.9%	70	7.6%
1977	659	7.5%	75	7.8%
1978	684	3.7%	78	3.7%
1979	759	11.1%	87	11.1%
1980	762	0.3%	87	0.0%
1981	752	-1.2%	86	-1.0%
1982	736	-2.2%	84	-2.2%
1983	710	-3.5%	81	-3.5%
1984	747	5.2%	85	4.9%
1985	779	4.3%	89	4.6%
1986	670	-13.9%	77	-13.9%
1987	644	-4.0%	73	-4.0%
1988	675	4.9%	77	4.6%
1989	740	9.7%	84	10.0%
1990	968	30.8%	111	30.8%
1991	1,537	58.8%	175	58.8%
1992	1,348	-12.3%	154	-12.5%
1993	1,557	15.5%	178	15.8%
1994	1,811	16.3%	207	16.3%
1995	1,583	-12.6%	181	-12.6%
1996	1,285	-18.8%	146	-19.1%
1997	674	-47.5%	77	-47.4%
1998	716	6.2%	82	6.2%
1999	568	-20.6%	65	-20.6%
2000	587	3.3%	67	3.1%
2001	538	-8.4%	61	-8.2%
2002	454	-15.7%	52	-15.7%
2003	346	-23.6%	40	-23.6%

table 31

Contract Off-System Load

Projected Contract Off-System Sales and Load, 2004-2006

Year	Billed Sales (000s of MWh)	Percent Change	Average Load (megawatts)	Percent Change
2004	26	-92.6%	3	-92.6%
2005	11	-57.6%	1	-57.4%
2006	0	-100.0%	0	-100.0%

table 32

Total Company Load

Historical Total Company Sales and Load, 1970-2003

(weather adjusted)

Year	Billed Sales (000s of MWh)	Percent Change	Average Load (megawatts)	Percent Change
1970	5,903		734	
1971	6,231	5.6%	775	5.6%
1972	6,775	8.7%	842	8.6%
1973	7,115	5.0%	886	5.2%
1974	7,559	6.2%	943	6.5%
1975	8,136	7.6%	1,017	7.8%
1976	8,576	5.4%	1,069	5.2%
1977	8,844	3.1%	1,104	3.2%
1978	9,336	5.6%	1,171	6.1%
1979	9,875	5.8%	1,231	5.1%
1980	10,042	1.7%	1,249	1.4%
1981	10,442	4.0%	1,302	4.3%
1982	10,288	-1.5%	1,283	-1.5%
1983	10,311	0.2%	1,289	0.5%
1984	10,509	1.9%	1,303	1.1%
1985	10,611	1.0%	1,323	1.5%
1986	10,515	-0.9%	1,311	-0.9%
1987	10,746	2.2%	1,336	1.9%
1988	11,045	2.8%	1,374	2.8%
1989	11,632	5.3%	1,452	5.7%
1990	12,067	3.7%	1,507	3.8%
1991	12,836	6.4%	1,595	5.8%
1992	12,821	-0.1%	1,599	0.2%
1993	13,213	3.1%	1,636	2.3%
1994	13,804	4.5%	1,726	5.5%
1995	14,176	2.7%	1,755	1.7%
1996	14,350	1.2%	1,795	2.3%
1997	13,951	-2.8%	1,746	-2.7%
1998	14,100	1.1%	1,760	0.8%
1999	14,036	-0.5%	1,758	-0.1%
2000	14,893	6.1%	1,871	6.4%
2001	14,146	-5.0%	1,732	-7.5%
2002	13,130	-7.2%	1,646	-4.9%
2003	13,271	1.1%	1,671	1.5%

table 33

Total Company Load

Projected Total Company Sales and Load, 2004-2015

Year	*Billed Sales (000s of MWh)*	*Percent Change*	*Average Load (megawatts)*	*Percent Change*
2004	13,308	0.3%	1,678	0.4%
2005	13,659	2.6%	1,720	2.5%
2006	13,978	2.3%	1,760	2.3%
2007	14,315	2.4%	1,803	2.4%
2008	14,666	2.4%	1,846	2.4%
2009	15,000	2.3%	1,889	2.3%
2010	15,328	2.2%	1,930	2.2%
2011	15,647	2.1%	1,970	2.1%
2012	15,961	2.0%	2,008	2.0%
2013	16,274	2.0%	2,049	2.0%
2014	16,587	1.9%	2,088	1.9%
2015	16,898	1.9%	2,127	1.9%

table 34