SECTION 3

Electric Utility Information Reporting
Forecast Section

Form EN-00005-16

7610.0320 FORECAST DOCUMENTATION

2004 Long-range Sales and Demand Forecasts
Otter Tail Power Company

1. Introduction

These forecasts are the first done by the Regulatory Economics area of Regulatory Services. The methodology is a change from the previous 11 forecasts done using the end-use framework in SHAPES-II. The methodology was changed from an end use to an econometric model per the Minnesota Public Utilities Commission order in docket E-017/RP-02-1168 issued March 20,2003, *Item 2. Implement a different energy and demand forecasting methodology.* Otter Tail Power Company staff met with staff from The Department of Commerce on April 21, 2003 and with their advice determined the general approach to employ. Otter Tail Power Company employed Christiansen Associates of Madison, Wisconsin to develop a traditional econometric forecasting model to replace the previous end-use model. The main purpose of this forecast is for use in the Integrated Resource Plan (IRP). Other work areas in the Company provided information and assistance.

2. Forecast results

This section describes the results of the forecast. The sales forecast is presented first, followed by the peak-demand forecast. The forecast includes two alternatives generated from a confidence interval around the forecasted demand values. All data represents Otter Tail Power Company alone. There are no contractual pool sales to municipal or agency loads commingled in these results. Only the portion of load in excess of load from other suppliers used by municipals or agencies and served at retail are included in this forecast.

3.1. Sales forecast

The sales forecast consists of a base forecast and two alternative scenarios. The base forecast is the most-likely estimate of future load based on the data provided in the model. The alternative forecasts are generated using the uncertainty around the estimated parameters of the forecasting equation system peak model which contains an estimate of the effect of weather on peak demand. That parameter estimate has a standard error associated with it that can be used to generate a confidence interval around the forecasted demand value (e.g., there is some probability that the "true" value of the parameter is actually larger than the estimated value, which would imply that the effect of weather on demand would be larger, leading to a higher peak demand for a given assumed weather condition). It is important to note that when the confidence interval around the demand forecast is calculated in this way, the values of the explanatory variables, such as weather, economic growth, and demographics are all maintained at fixed assumed, or expected levels (e.g., there is no accounting for the forecast uncertainty due to the fact that weather conditions in some of the forecast years are likely to differ from the expected conditions). The scenarios represent about a 10% spread above and below the base.

This forecast represents unmanaged sales, that is, for the purpose of this forecast it is assumed that the load management system is not being used to control customer loads. Control is another step in preparation of the IRP and done by Resource Planning at the time the IRP is prepared.

3.1.1 Growth rates and scenario spread

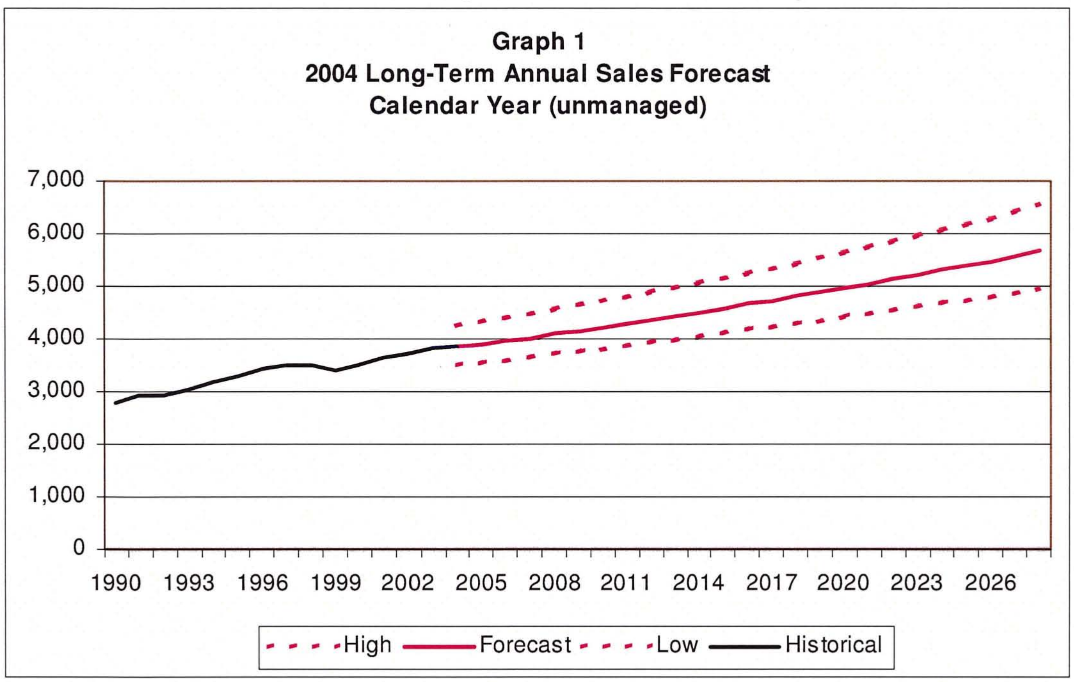
Table 1 summarizes the growth of the sales forecast. Sales growth in this forecast is primarily due to increases in electric use and secondarily due to customer growth and other factors.

Table 1
2004 Sales Forecast Statistics
Average Compounded Growth Rates

Years	Low Forecast	Sales Forecast	High Forecast
2004 to 2028	1.43%	1.67%	1.92%

3.1.2 Sales data

The actual listing of the sales forecast is shown in Graph 1 and Table 2. The graph shows that the forecast and scenarios smoothly continue from the historical sales.



Ten-year (2004 to 2014) energy growth statistics by class are: 0.3% for residential, 0.9% for commercial class, 2.5% for industrial and 0.3% for miscellaneous/other-public-authority. The latest forecast for large pipelines predicts about 1.9% growth. These numbers are based on the raw model class totals.

Table 2
2004 Long-Term Forecast

Annual Sales Forecast (Unmanaged)
Gigawatt-hours

Year	Low	Low Annual Growth %	Forecast	Forecast Annual Growth %	High	High Annual Growth %	Net Energy for Load / System Input*
2003	3524.882		3822.641		4165.023		4090.226
2004	3506.198	-0.5%	3849.922	0.7%	4251.576	2.1%	4119.416
2005	3531.685	0.7%	3893.305	1.1%	4317.469	1.5%	4165.837
2006	3580.371	1.4%	3953.903	1.6%	4392.385	1.7%	4230.676
2007	3632.454	1.5%	4016.929	1.6%	4468.428	1.7%	4298.114
2008	3697.991	1.8%	4094.666	1.9%	4560.690	2.1%	4381.292
2009	3741.248	1.2%	4147.888	1.3%	4625.857	1.4%	4438.240
2010	3797.429	1.5%	4215.705	1.6%	4707.641	1.8%	4510.804
2011	3854.693	1.5%	4285.084	1.6%	4791.621	1.8%	4585.040
2012	3925.539	1.8%	4369.996	2.0%	4893.507	2.1%	4675.896
2013	3972.267	1.2%	4428.505	1.3%	4966.373	1.5%	4738.500
2014	4031.815	1.5%	4501.669	1.7%	5056.149	1.8%	4816.786
2015	4092.381	1.5%	4576.443	1.7%	5148.326	1.8%	4896.794
2016	4166.254	1.8%	4666.528	2.0%	5258.292	2.1%	4993.185
2017	4214.702	1.2%	4728.666	1.3%	5337.426	1.5%	5059.673
2018	4276.335	1.5%	4806.051	1.6%	5434.370	1.8%	5142.475
2019	4338.234	1.4%	4884.227	1.6%	5532.844	1.8%	5226.122
2020	4414.782	1.8%	4979.476	2.0%	5651.409	2.1%	5328.040
2021	4464.785	1.1%	5045.457	1.3%	5737.586	1.5%	5398.639
2022	4529.455	1.4%	5128.560	1.6%	5843.954	1.9%	5487.559
2023	4595.021	1.4%	5213.318	1.7%	5953.031	1.9%	5578.250
2024	4675.635	1.8%	5315.811	2.0%	6083.223	2.2%	5687.917
2025	4728.399	1.1%	5387.402	1.3%	6179.011	1.6%	5764.520
2026	4798.382	1.5%	5479.170	1.7%	6298.700	1.9%	5862.712
2027	4869.986	1.5%	5573.454	1.7%	6422.168	2.0%	5963.596
2028	4958.555	1.8%	5687.815	2.1%	6569.665	2.3%	6085.962

3.2. Peak-demand forecast

Tables 3 and 4 summarize the growth rates of the 2004 peak-demand forecast. It can be seen from these tables that all scenarios show growth over the 2004-2028 forecast period. Winter peak demand growth rates and summer peak demand growth rates are similar to the previous forecast. There are no surprising changes. Please refer to the tables for the actual numbers.

Table 3
2004 Summer Peak Forecast Statistics (Unmanaged)
Average Compounded Growth Rates

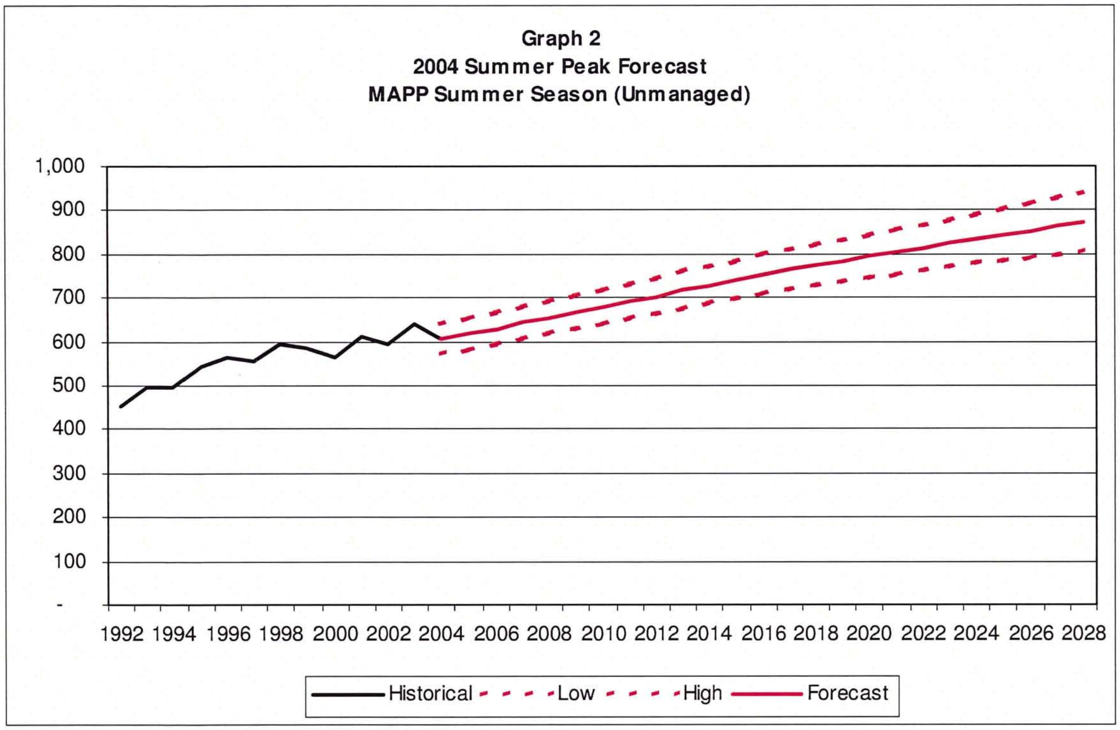
Years	Low Forecast	Forecast	High Forecast
2004 to 2028	1.42%	1.52%	1.60%

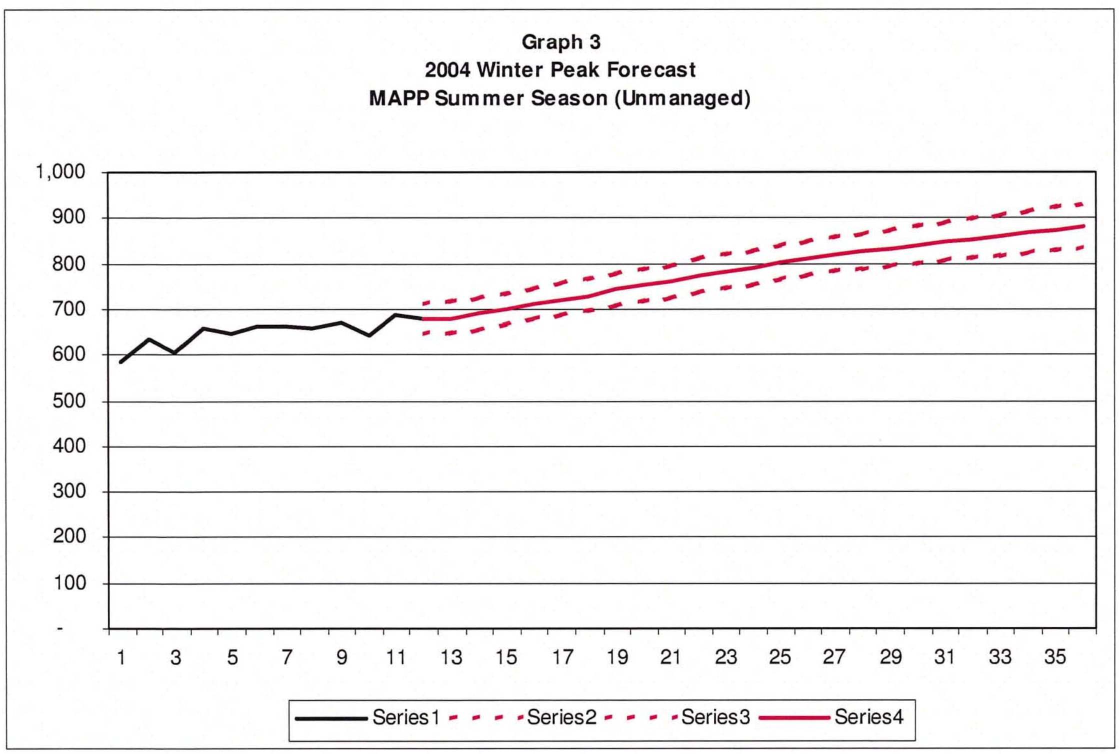
Table 4
2004 Winter Peak Forecast Statistics (Unmanaged)
Average Compounded Growth Rates

Years	Low Forecast	Forecast	High Forecast
2004 to 2028	1.07%	1.11%	1.15%

Graphs 2 and 3 show how the summer and winter peak-demand forecasts appear with the scenarios. Historical peaks are also displayed on the graphs.

Again, it's important to point out that the high and low scenarios represent situations where saturations change in ways that contribute to the additional growth of customer electricity use or change in ways that reduce customer electricity use. Actual growth is intended to be between the two scenarios, with the best estimate being along the forecast scenario line.


Graph 2
2004 Summer Peak Forecast
MAPP Summer Season (Unmanaged)
1,000
900
800
700
600
500
400
300
200
100
-
1992 1994 1996 1998 2000 2002 2004 2006 2008 2010 2012 2014 2016 2018 2020 2022 2024 2026 2028
Historical
Low
High
Forecast


Graph 3
2004 Winter Peak Forecast
MAPP Summer Season (Unmanaged)
1,000
900
800
700
600
500
400
300
200
100
-
1 3 5 7 9 11 13 15 17 19 21 23 25 27 29 31 33 35
Series1
Series2
Series3
Series4

Electric peak demands are very sensitive to external forces. They display wide swings that may be attributable to high saturations of controllable electric space heating loads, customer perceptions of electric price with respect to competing fuels, and weather, among other factors. The true level of demand growth, consequently, can be hard to predict. Since there are irreconcilable shifts in system peak loads from year to year, it is assumed that the highest peaks are the best indicators of the true load level. Therefore, the most important forecasting objective is for the highest observed peaks to fall within the forecast region bounded by the high and low scenarios.

Tables 5 and 6 detail the actual peak demand forecast for the summer and winter seasons. This data is listed by MAPP year where, by definition, the Summer Season precedes the Winter Season. The Winter Season follows into the next calendar year. For example, Summer 2004 falls in May through October of 2004, where Winter Season 2005 is November 2004 through April 2005. This model projects in monthly intervals through December of 2028. Consequently, a January peak for Winter Season 2028-2029 is not available.

Table 5
2004 Long Term Forecast
Summer Peak Demand Forecast
MAPP Summer Season w/losses
at Time of Peak (Unmanaged)
Megawatts

year	Low	High	Forecast	% change
2003				
2004	572	642	607	
2005	583	653	618	1.8%
2006	593	665	629	1.8%
2007	608	681	644	2.4%
2008	618	692	655	1.7%
2009	628	704	666	1.6%
2010	643	719	681	2.3%
2011	653	731	692	1.6%
2012	663	743	703	1.6%
2013	677	759	718	2.2%
2014	687	770	729	1.5%
2015	697	782	739	1.5%
2016	711	798	754	2.0%
2017	720	809	764	1.4%
2018	729	820	774	1.3%
2019	737	831	784	1.2%
2020	745	842	794	1.2%
2021	753	854	803	1.2%
2022	761	865	813	1.2%
2023	768	877	823	1.2%
2024	776	889	832	1.2%
2025	783	901	842	1.2%
2026	790	914	852	1.1%
2027	796	926	861	1.2%
2028	803	940	871	1.2%

Table 6
2004 Long Term Forecast
Winter Peak Demand Forecast
MAPP Winter Season w/losses
at Time of Peak (Unmanaged)
Megawatts

year	Low	High	Forecast	% change
2003	647	715	681	0.4%
2004	656	724	690	1.3%
2005	665	733	699	1.3%
2006	678	747	712	1.9%
2007	686	756	721	1.3%
2008	695	765	730	1.2%
2009	708	778	743	1.8%
2010	716	787	752	1.2%
2011	725	796	760	1.2%
2012	737	809	773	1.7%
2013	746	818	782	1.1%
2014	754	827	790	1.1%
2015	766	839	803	1.6%
2016	773	848	811	1.0%
2017	780	856	818	0.9%
2018	787	863	825	0.9%
2019	793	871	832	0.9%
2020	800	879	840	0.9%
2021	806	888	847	0.8%
2022	811	896	854	0.8%
2023	816	905	861	0.8%
2024	821	913	867	0.8%
2025	826	922	874	0.8%
2026	830	932	881	0.8%
2027	835	941	888	0.8%

4. Principal influences on the forecasts

The following are brief discussions of the primary influences on the forecasts. These items have been considered significant as influential because they are the inputs that are regularly updated as new data becomes available. The tables below describe the variables used in the forecasts.

Table 7

Data Used in Energy Forecast Models

	logkwhday	*cddday*	*hddday*	*logcust*	*logques1*	*logques32*	*logques37*	*logrealgdp*
Residential-MN	x	x	x	x				
Residential-ND	x	x	x	x				
Residential-SD	x	x	x	x				
Farm-MN	x	x	x					
Farm-ND	x	x	x			x		
Farm-SD	x	x	x			x		
Small Comm-MN	x	x	x					x
Small Comm-ND	x	x	x					x
Small Comm-SD	x	x	x					x
Large Comm-MN	x	x	x					x
Large Comm-ND	x	x	x					x
Large Comm-SD	x	x	x					x
OPA-MN	x		x					
OPA-ND	x	x	x				x	
OPA-SD	x		x				x	
Streetlight-MN	x				x			
Streetlight-ND	x				x			
Streetlight-SD	x				x			
Pipeline-MN	x		x					x
Pipeline-ND	x							
Malting-ND	x							
Unclassified-MN	x	x	x				x	
Unclassified-ND	x	x	x					
Unclassified-SD	x	x	x					

- *logkWh day*: the log of average daily energy use for each class for each month
- *cddday*: average daily cooling degree days for each month
- *hddday*: average daily heating degree days for each month
- *logcust*: the log of the customer count for the residential class
- *logques1*: the log of total population – Woods & Poole
- *logques32*: the log of farm total employment – Woods & Poole
- *logques37*: the log of transportation, communications and public utilities total employment– Woods & Poole

- *Logrealgdp*: the log of real gross domestic product Quarterly Real Gross Domestic Product (GDP) data was downloaded from www.bea.doc.gov/bea/dn/gdplev.xls . Real GDP was based on 1996 dollars.

Table 8

Data Used in Demand Forecast Models									
	KW	*ques70*	*realgdp*	*srealgdp*	*sthibuildup*	*swthibuildup*	*wfaws*	*whddbuildup*	*swcddhddbuildup*
Demand-System	x	x	x	x	x	x	x	x	x

- *kw*: monthly maximum demands including controlled load, excluding pipeline demands
- *ques70*: number of households Woods & Poole
- *realgdp*: real Gross Domestic Product
- *srealgdp*: summer real Gross Domestic Product
- *swthibuildup*: swing months temperature humidity index buildup
- *wfaws*: winter Fargo wind speed
- *whddbuildup*: winter heating degree day buildup
- *swcddhddbuildup*: swing month cooling and heating degree buildup

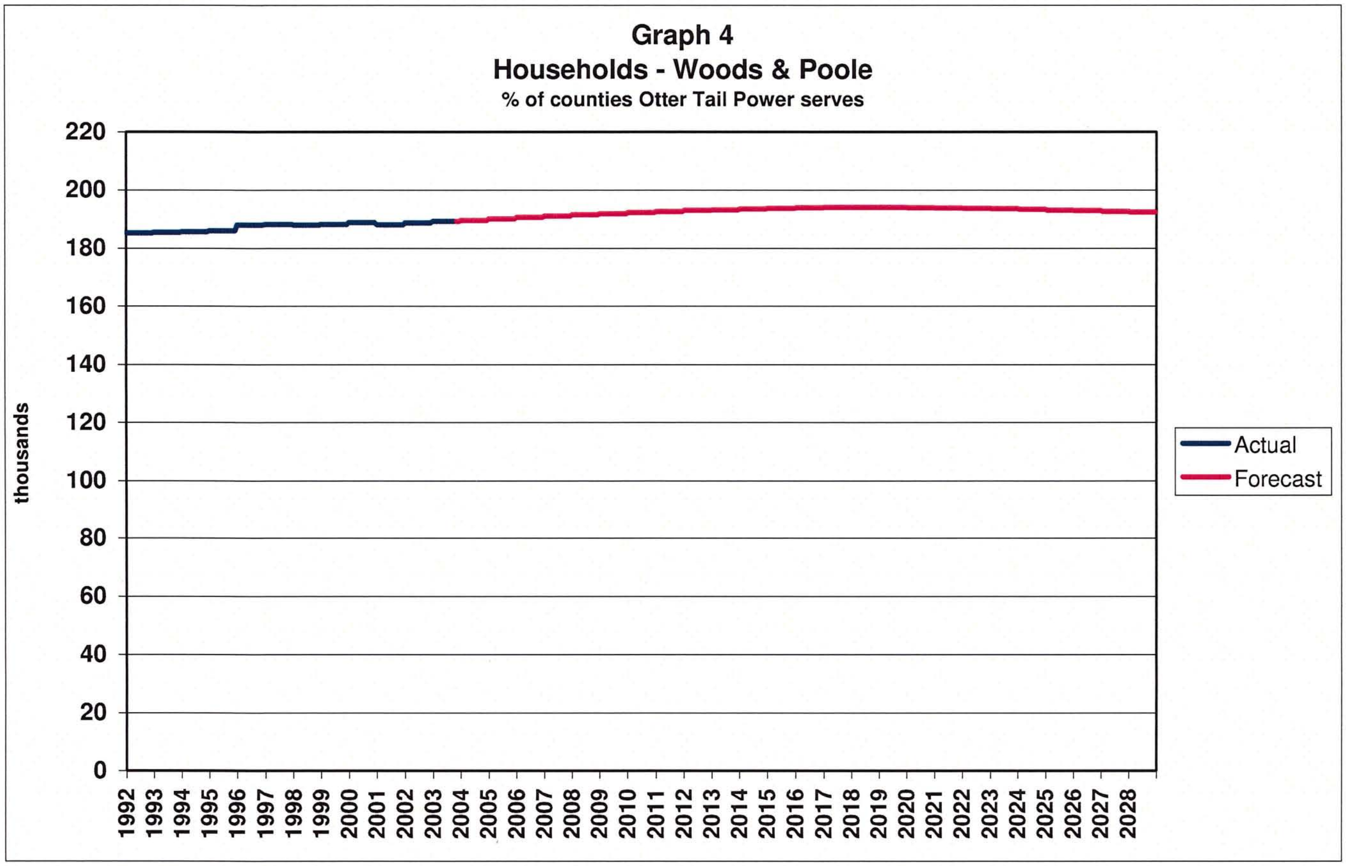
Average hourly temperature data was obtained by averaging hourly temperatures across 14 division monitoring stations throughout Minnesota, North Dakota and South Dakota. Daily heating degree days (*hdd*) and cooling degree days (*cdd*) were calculated based on the standard 65 degree base and the rounded average of daily high and daily low temperatures.

Hourly weather data files were obtained from the High Plains Regional Climatic Center (http://www.hprcc.unl.edu/) for Fargo, ND. Fargo is used as a proxy for the system average weather data (other than temperatures which come from Otter Tail Power Company division weather stations).

Quarterly real Gross Domestic Product (GDP) data was downloaded from www.bea.doc.gov/bea/dn/gdplev.xls . Real GDP was based on 1996 dollars. Real GDP data for the forecast period was based on the growth of the Woods and Pool forecast for Total Earnings of Employees for the United States (question 45)

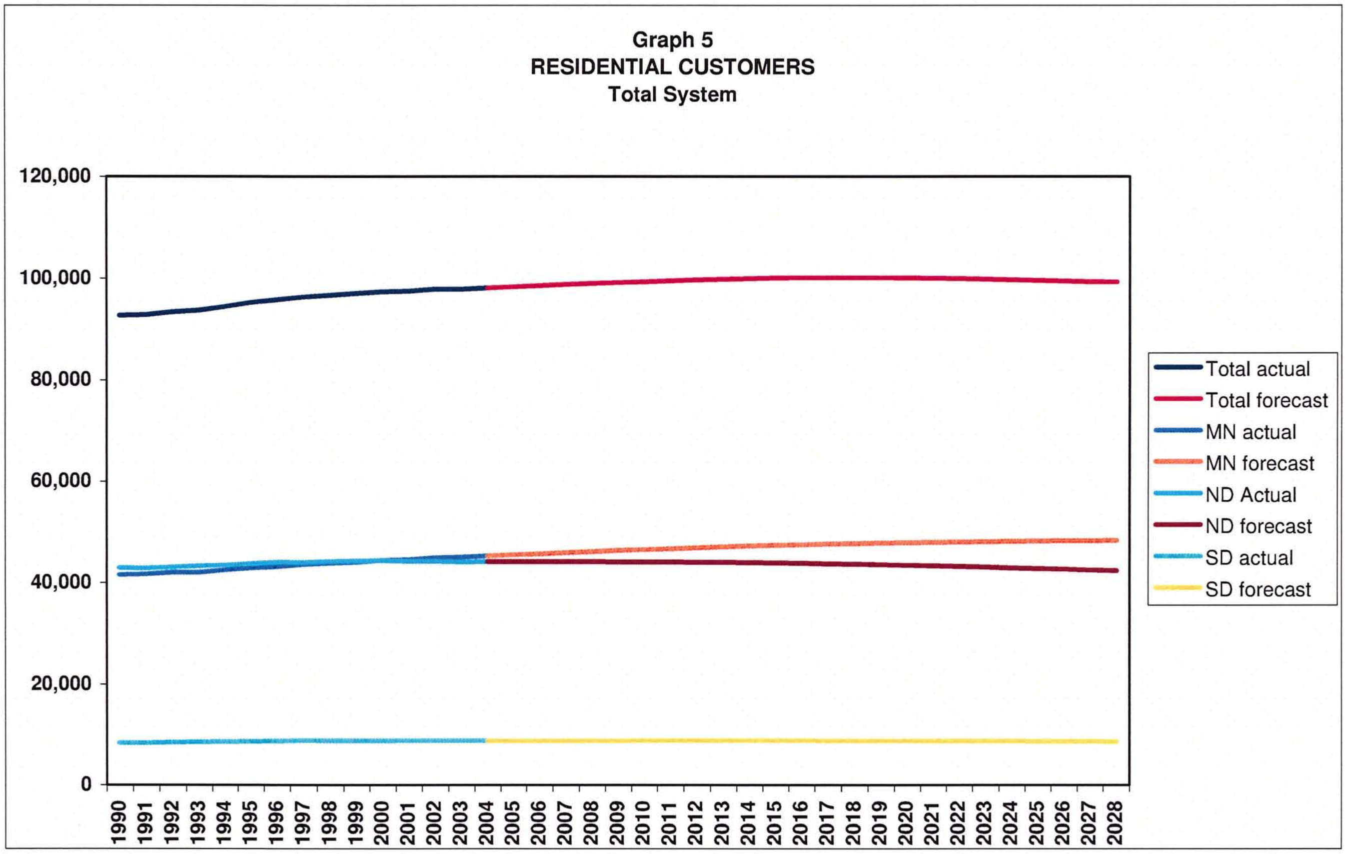
5.1. Population and households

Population and household projections were obtained from Woods and Poole Economics, Inc. (W&P). Their projections are based on a standard demographic model that takes into account births, deaths, and migration rates. The W&P National model assumes that regional population will grow at or below the national average until 2028. Regionally, the population rate is expected to increase at about 0.68 percent. Woods and Poole points out that a wide disparity in growth exists from county to county. Most counties in the OTP service territory demonstrate little or negative growth. Only 6 counties of over 10,000 households are expected to show growth and of those, only 2 are predominately served by OTP. Agricultural counties continue to have strong production but declining farm population.



Otter Tail Power serves load in 75 counties. An earlier study identified counties that are predominately served by Otter Tail Power Company which, taken together, tend to be primary indicators of growth. We refer to these counties as "10% Counties". [2] Population characteristics and employment projections of these counties were used in the Otter Tail model to develop projections of the future number of households (Graph 4) and residential customers (Graph 5.

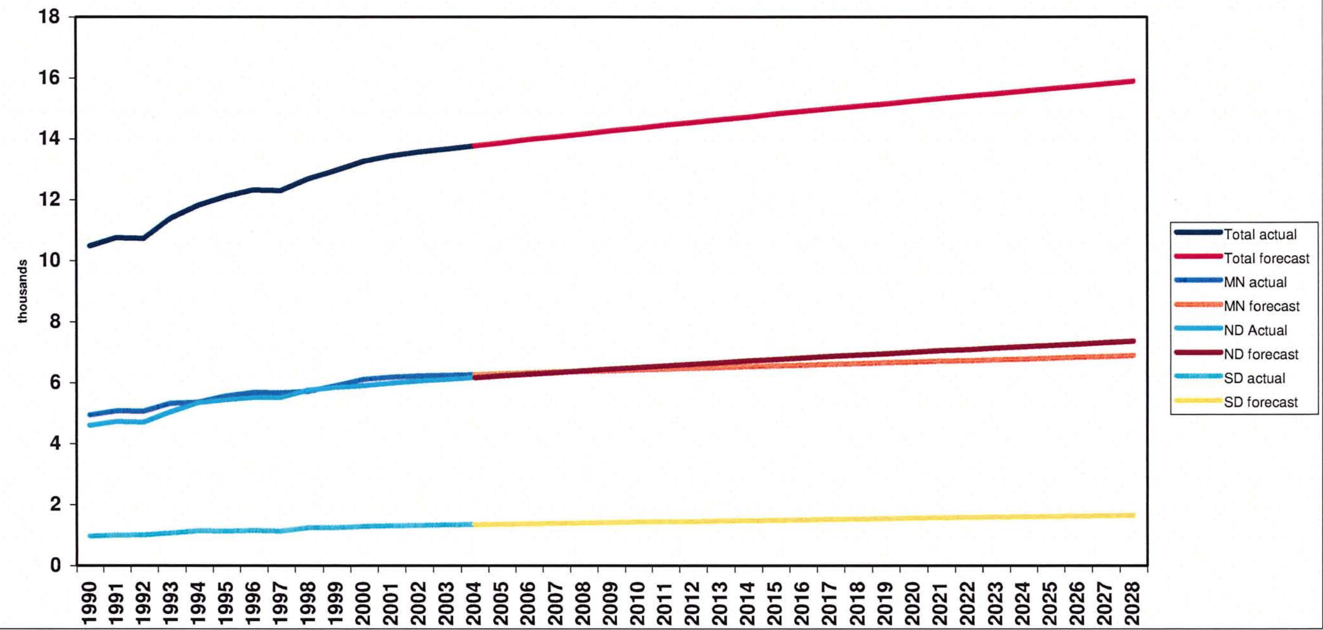
[2] This study showed that counties in which the total population of Otter Tail towns was less than about 10 percent of the total population of the county were not representative of the predominant growth trends of the Otter Tail system so they were dropped from aggregations of county data. Counties dropped included Cass (Fargo), Burleigh (Bismarck), and Grand Forks (Grand Forks).



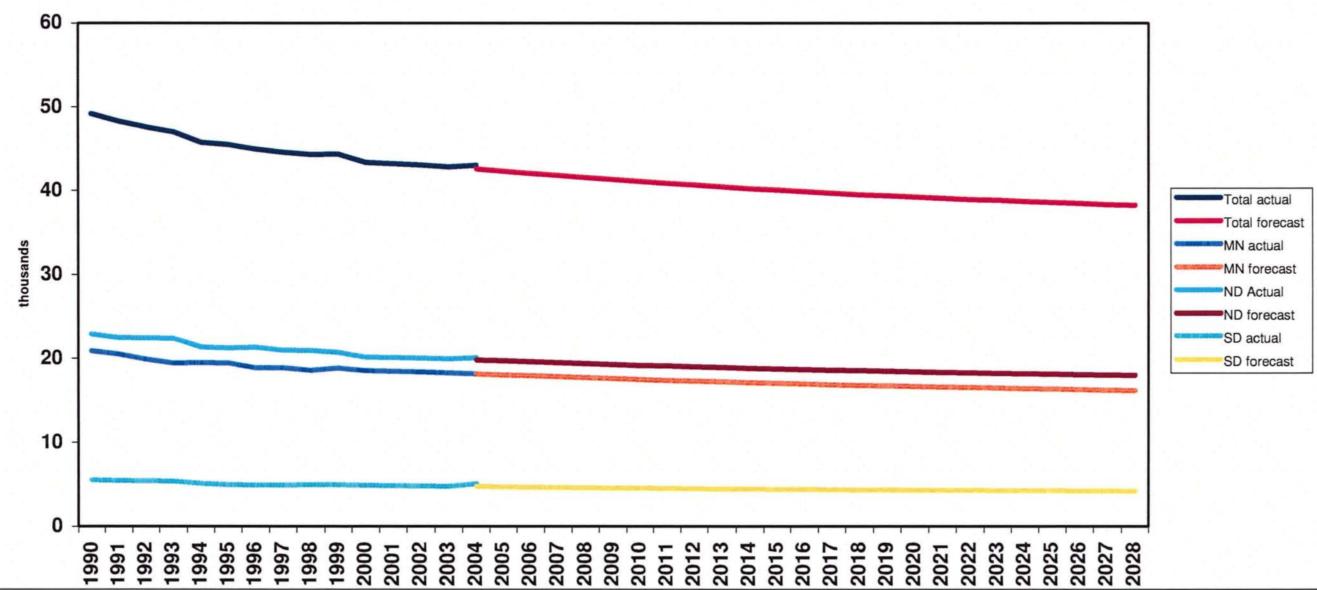
5.2 Employment

The Woods and Poole projections for employment, that are used in this forecast, in the counties representing the Otter Tail service territory, are shown in Graphs 6 & 7. Regionally, the growth is expected to be in about 1.12 % with only a few counties showing robust growth. The majority are either flat or declining.

Graph 6
Transportation, Communications and Public Utilities - Employment

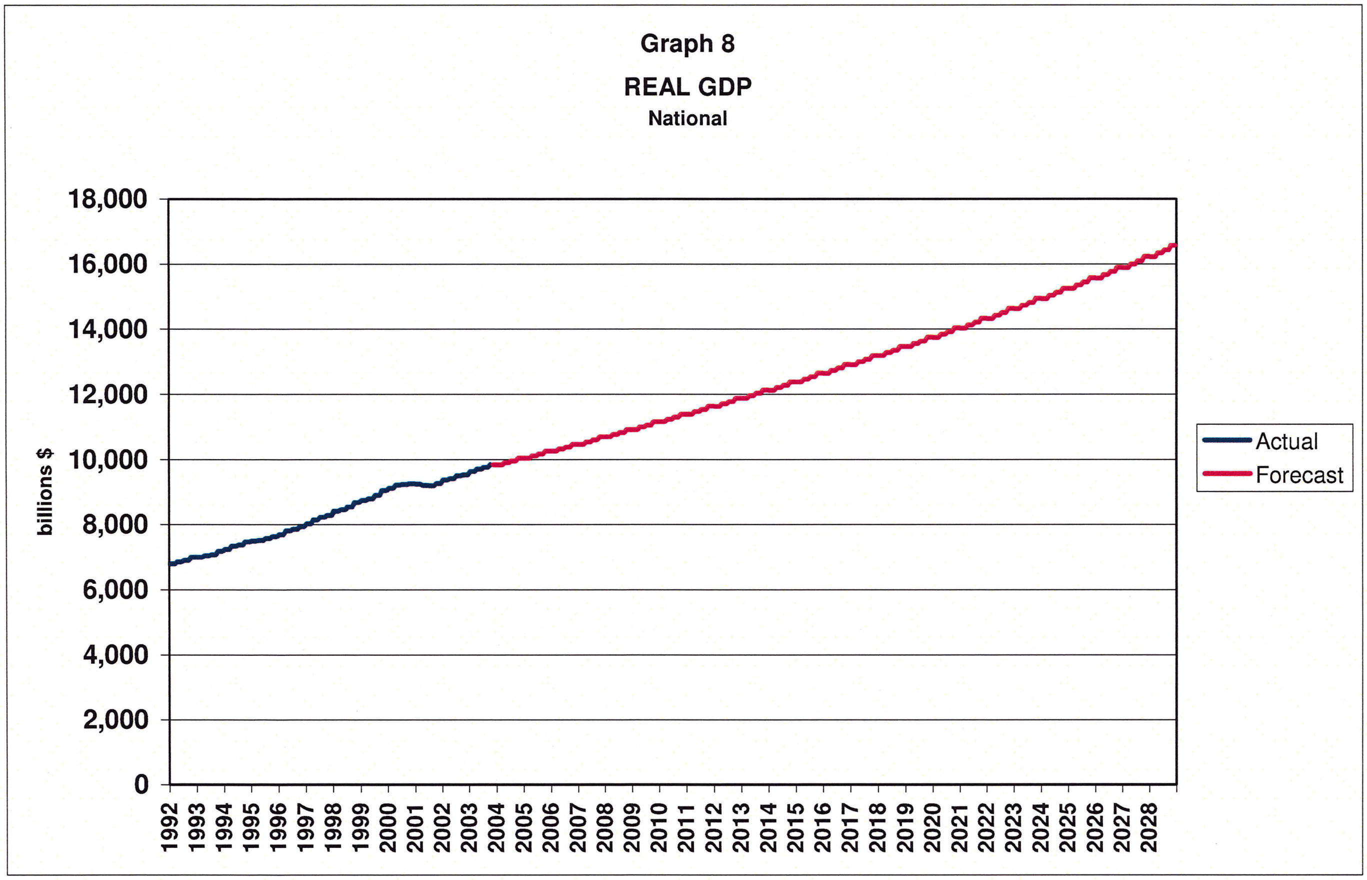


Graph 7
Farm Employment
Total System



5.3. Prices and GDP (gross domestic product)

In the model, price was tested as a variable and found not to have a statistically valid correlation. Price projections tested for use in this forecast are company average prices, including all sectors of usage. A review of Otter Tail Power's sales relative to price shows Otter Tail Power's sales are relatively inelastic. While there were a couple of swings that may be thought to be due to consumer reaction to prices, there were significant events during the late 1970's and 1980's. The most significant event is the energy crisis of the late 70's, when consumers reacted to consumption of all forms of energy by conserving. This helped to change annual growth curves from 7% range to the 3% range. The growth rate started to shift before prices started to rise. Along with the energy crisis came high interest rates, decreasing disposable income creating a focus on conserving costs wherever possible for consumers. Anyone who bought a house in the early 80's remembers mortgage rates as high as 15% or more. Many efficient conservation steps were achieved during the 80's and these have carried into today. While price has an impact on consumption, in a 3% or less growth environment, short of a doubling of prices, it is an indirect impact versus general economic condition. This is why GDP is used in both the sales model and the demand model. Real GDP (Graph 8) is about 2.1% over the course of the forecast period



5.4. Temperature and the forecast

The primary driver of the day-to-day variation of electric load is temperature. While historical load responds to the temperature that occurs at the time the load is measured, the load forecasting process raises the question of what temperatures should be used for the unknown future**.**

The energy forecast was created using hourly temperature data obtained from 14 division monitoring stations throughout Minnesota, North Dakota and South Dakota. Scheduled billing cycle start and stop dates were obtained from the Customer Information System (CIS). Daily heating degree days (*hdd*) and cooling degree days (*cdd*) were calculated for each monitoring station based on the standard 65 degree base and the rounded average of daily high and daily low temperatures. Daily degree days were then averaged for each state and added to calculate billing month and calendar month heating degree days and cooling degree days. Average daily *hdd* and *cdd* were calculated over a 20 year period to calculate normal billing month and calendar month *hdd* and *cdd*. Billing month *hdd* and *cdd* per day were found by dividing billing month *hdd* and *cdd* by the average number of days in each month's billing cycles. Calendar month *hdd* and *cdd* per day were found by dividing calendar month *hdd* and *cdd* by the number of days in the calendar month. Billing month *hdd* and *cdd* were used for the historical period and calendar month *hdd* and *cdd* were used for the forecast period.

For **the Demand Forecast**, hourly weather data files were obtained from the High Plains Regional Climatic Center (http://www.hprcc.unl.edu/) for Fargo, ND. Fargo is used as a proxy for the system average weather data (other than temperatures which come from Otter Tail Power, Company division weather stations). The hourly temperature humidity index (*thi*) was calculated, from the hourly dry bulb temperatures and the hourly relative humidity (*thi*=*db*-(.55-,.55***rh*/100)**(*db*-58)). Average daily temperature humidity index (*thi*) and wind speed (*faws*) were calculated from the hourly values. The variable *thibuildup* was calculated from *thi* for the day of monthly system peak and *thi* from the previous three days so that each previous day has half the influence of following day ((40/75)**thi*+(20/75)**lag1thi*+(10/75)**lag2thi*+(5/75)* *lag3thi*). The variable *sthibuildup* has the value of *thibuildup* for the months of June, July and August and zero for all other months. The variable *swthibuildup* has the value of *thibuildup* for the months of May and September and zero for all other months. The variable *wfaws* is Fargo wind speed for the months of January, February, March, April, October, November and December and zero for all other months. Forecast period *sthibuildup*, *swthibuildup* and *wfaws* variables were calculated by determining the value of *thi* for each monthly system peak day and the three days previous to the peak for the last 12 years. Peak day average wind speed was also determined for each of these months. Monthly average values for each of the variables over the 12-year period were calculated and used to calculate *sthibuildup*, *swthibuildup* and *wfaws* for the forecast period. The demand forecast also uses average hourly temperature data obtained by averaging hourly temperatures across 14 division monitoring stations throughout Minnesota, North Dakota and South Dakota to calculate the variables *hddbuildup, cddbuildup, swcddhddbuilup and whddbuildup* (*whddbuildup*: winter heating degree day buildup, *swcddhddbuildup:* swing month cooling and heating degree buildup).

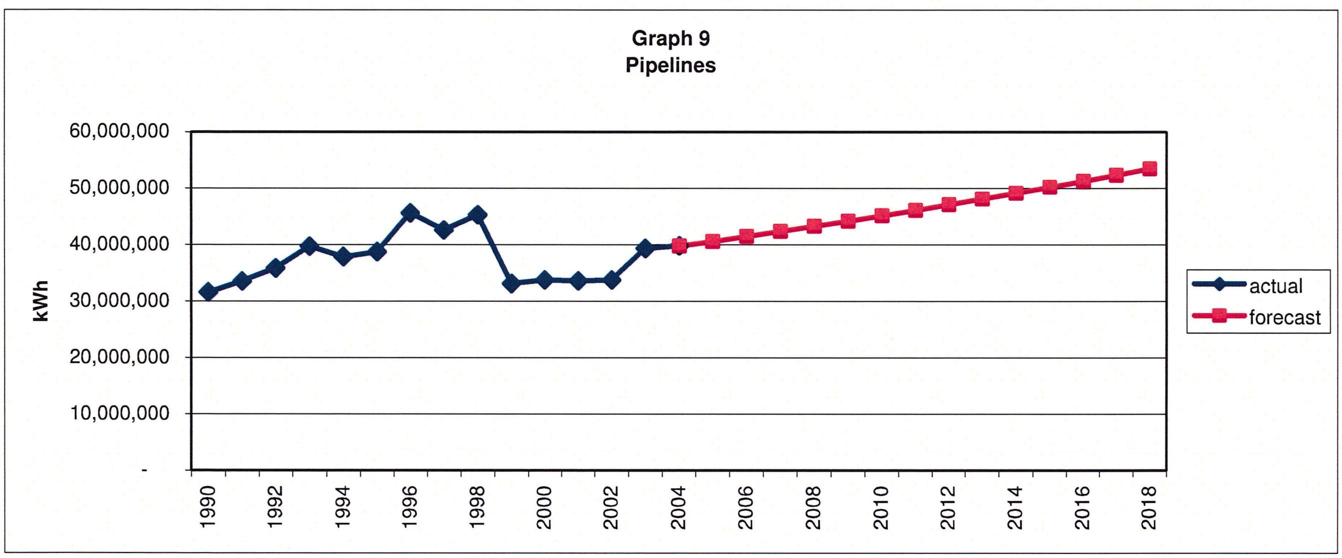
5.5. Pipeline Forecasts

A major influence on the forecast comes from Lakehead Pipe Line Partners, L. P. now known as Enbridge Inc. In the last few years the customer has provided a limited energy forecast to Otter Tail Power Company for the purposes of budgeting. Their five-year forecast is generally used as a starting point and is then extended out to the long-range forecast horizon. In the past, they projected growth for only 1 or 2 years and then merely repeated the sales figures out to the five year forecast horizon. OTP would then extend this projection out 20 or so years. This practice is undesirable because it ignores the historical growth of this significant customer. The combined forecast for both Enbridge Pipeline and Minnesota Pipeline (a much smaller pipeline customer) is shown in Graph 9.

The company's annual reports repeatedly declare that their growth potential is very good for at least the next 10 years. This anticipated growth is driven primarily by the North American demand for domestic crude oil and the alternative demand for foreign oil. The drillers and suppliers in the oil rich regions of western Canada meet that demand and the pipeline usage responds by delivering the product to market.

Enbridge has a contract (approved by the Minnesota Public Utilities Commission) with Otter Tail Power which limits their demand. The level was set at 30 MW when this forecast was prepared. For forecasting, the demand is increased between 2 and 4 MW every 3 years.

Data was reviewed from Enbridge's "Oil Sands Market Study - 2003" and Canada's National Energy Board publication: "Canada's Energy Future: Scenarios for Supply and Demand to 2025 - 2003 – Revised".



6. Demand-side management

Demand-side management (DSM) and conservation activities are not specifically identified in the forecast. These activities have been common practice for many years in the form of insulation programs, appliance promotions, and others. New or individual DSM and conservation programs are assumed to have the same impact on total appliance-use trends that they have had in the past.

7. NERC Planning Standards

NERC Planning Standards are addressed in this section as required for the analysis of the reliability of the interconnected transmission system. Other areas of the company have principal responsibility for detailed reports so they are not included in this report. Those sources will only be referenced here.

II.D.S1-S2.M1: This measurement requests a description of the scope and specificity of actual and forecast load data and controllable demand-side management data. Actual load is saved in files commonly known as NERC files. Their format is a two-line 80-column format called an EEI format. Monthly Peak loads and net energy for load data are reported in a periodic report called the Historical Load Data report. These are both compiled in the System Operation Department. Load and Capability reports based on this forecast are submitted to MAPP in the MAPP 411 report. Demand Side Management details and forecasts are reported to the Department of Energy in EIA-861. These reports are compiled in the Resource Planning Department. A report called the Demand-side Management Financial Incentive Project details historical DSM programs and data. The Market Planning Department maintains this report. None of these reports are reproduced in this forecast documentation, but are available on request.

II.D.S1.M4: This measurement describes what information is to be provided annually to NERC. Subpart a. (historical hourly load files) and subpart b. (Monthly and annual peak hour actual demands and net energy for load) are provided to NERC in the Actual Load-generating Data report by another area of the company. Subpart c. requiring monthly peak hour forecast demands and net energy for load for the next two years are, in fact, the basis for the seasonal demands reported in this document. This information is reported in the MAPP 411 report. The full month-by-month series is available on request. Annual peak forecasts for summer and winter seasons are in Tables 5 and 6. Annual net energy for load is in Table 2.

II.D.S1.M6: This measurement relates to information about whether non-member entities are included in this forecast. Non-member entities are generally not included in the forecasts. Otter Tail Power Company provides power above the WAPA allocation to some entities at retail and this energy is included in Otter Tail Power Company sales reporting and is also included in this forecast.

II.D.S1.M7: This requires a description of how uncertainties are treated in the forecast. The assumptions, methods and the manner in which uncertainties are addressed in the forecasts are described in section 4 & 5 of this documentation. The principal sensitivity analysis is in the weather and economic variables.

II.D.S2.M10: Interruptible demands and direct load management data shall be provided up to ten years into the future for summer and winter peak conditions. These data are submitted to MAPP in the form of Schedule L and Schedule 411; also to the Department of Energy in the EIA-861 report as mentioned in measurement 1.

II.D.S2.M12: Forecasts shall show how demand and energy effects of demand-side management programs are addressed. As described earlier, the load management programs are all assumed inactive at the time of the peak loads detailed in this forecast. This means that the appliances are not being controlled and are consuming electricity at the time of peak. Released energy programs are treated the same as load management programs and are not in use for the uncontrolled peak. Other company documents detail the many programs and impacts on the OTP system so they are not elaborated on here. More detail can be provided in the specific reports covering those programs, rates, or control systems. Other studies have been done, as well, that can elaborate on the impacts of current DSM programs. Contact the Resource Planning Development department for more information.

8. Impacts of new technologies

Recent discussions raise questions of how new energy technologies are handled in the forecast. Specifically, these might be electric vehicles, self-generation, and new loads such as computer and network related development. While none of these items are specifically in the forecast because of the general nature of load estimation used in the forecast methodology, they certainly could be included in the future as more information is available.

Customer owned generation has primarily been intended for peak shaving situations and, since this forecast assumes all controllable loads are not being controlled, the self-generation capability is not being used.

Estimates have been made attributing significant load nationwide to computers and the Internet infrastructure. This technology is not specifically modeled in this forecast, but a case may be made to say that its effect is in there.

9. Conclusions

9.1. Summary of results

The 2003 forecast of sales and demand shows that potential for growth continues to exist. The number of customers and employment projections indicate growth potential, although limited primarily to a few counties. The potential for increased ownership of electric powered appliances is encouraging in view of the recent high gas and oil prices. The market environment of the large pipeline customer projections holds the potential for their continued growth in electric pumping. Near-term sales growth is fairly level due to the increasing cost of electricity due to increases in the fuel adjustment clause rates in recent years. Prices have just started to increase in real terms, but not to the magnitude of alternate fuels, thus still making electricity a more competitive and stable fuel source contrary to the short-term volatility of fossil fuels. The increasing demand to use natural gas for electric generation holds the possibility of continuing higher natural gas prices. These factors increase the possibility of continuing growth in electric sales. While resulting forecasts of the sales of electricity show an increase in the near term, they are more uncertain in the long term. The OTP service territory is, for the most part, a slow growing region with the only potential for significant residential growth coming from the spill-over of the larger urban areas not served by OTP. The long-term commercial growth will probably be similar to the past. Ag processing may be the primary driver for the industrial class. It is difficult to clearly project distant growth due to the many factors that can change, so the forecast resorts to generally projecting the status quo. System demand projections also show potential for increase in the near term although at a very low rate with summer peaks showing most growth. In the longer view, many uncertainties cloud the system demand picture. The likelihood of the increasing penetration of energy efficient appliances and the prospective loss and gain of customers due to wholesale competition are probably the greatest issues. Increasing fears of inflation, falling interest rates and an unsteady stock market slow potential expansion. The knowledge of anticipated future growth patterns is something that can only be watched. Woods and Poole Economics, Inc., anticipates that this decade should reveal increases in productivity in the service industries where it had been lagging behind the growth in the industrial sectors. Otter Tail Power may be seeing this effect in these forecasts. More productive labor means that commercial and industrial growth can occur without the expansion of the labor force and consequently the residential sector. Without increases in the residential sector, the municipal requirements don't change, as it is reflected in the miscellaneous/other-public-authority segment. The retail/commercial sector isn't growing as much either, because it provides services to people. Fewer people mean fewer services will be required.

The overall conclusion is there are many reasons to assume that electric use will continue to grow modestly into the future.

9.2. Future objectives

Since this is the first forecast done under this methodology some issues to be addressed in the next forecasting cycle include:

- As always, Forecasts provided by large customers will be reviewed and analyzed to test their validity.
- The models will be checked for accuracy against new historical data.

This concludes the 2004 forecast of supply and demand. Any comments or suggestions concerning this forecast, documentation, or methodology are welcome. The forecast becomes a more reliable and useful tool through the input of others. Please refer to the information at the beginning of the document for more details.