ESCANABA ELECTRIC DEPARTMENT

2003 LOAD FORECAST
for
POWER SUPPLY STUDY

FINAL REPORT

October 2003

Power System
Engineering Inc.

LOAD FORECAST

For

Escanaba Electric Department
Escanaba, Michigan

FINAL REPORT

Respectfully submitted,
Power System Engineering, Inc.

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(Published Separately)

1.0 INTRODUCTION

1.1 Background

Escanaba Electric Department (EED) has retained Power System Engineering, Inc. (PSE) to prepare a 2003 Power Supply Study to determine the needs for generation resources over the next 20 years and the preferred strategy for meeting those needs reliably and at reasonable cost. The Power Supply Study will be delivered in separate short reports on each key component of the power supply plan. This structure has been selected to provide EED with ample opportunity to review and amend, if necessary, each study component before proceeding to the next stage of the study.

This is the first report, which summarizes historic load growth for EED and develops forecasts of demand and energy requirements. Subsequent reports will address:

- The Power Supply Alternatives to be Evaluated
- Economic Evaluation of the Alternatives
- Implementation of the Preferred Power Supply Plan
- Executive Summary of the Power Supply Plan

Presentations will be provided to selected audiences in Escanaba as determined by EED to conclude the study.

1.2 Report Outline

In planning for cost-effective, reliable power supply, it is essential to have a sound forecast of both total energy requirements and seasonal peak demands. Since different customer classes respond to different growth factors, the best sales forecasts are developed by individual customer class. Total retail sales plus the utility's own use plus distribution losses define the total energy requirements at the generator and/or delivery point for purchases. Peak demands plus planning reserves define the design capacity requirements that the power supply plan will meet.

These components of the load forecast are developed in the following chapters:

Chapter 2	Location and Regional Trends
Chapter 3	The Residential Class
Chapter 3	The Commercial and Industrial Classes
Chapter 4	Other Classes
Chapter 5	Total Energy Requirements and Peak Demands

A significant part of the PSE load forecasting process is dedicated to the development of comprehensive databases that facilitate ongoing maintenance and updating of the load forecasts as an evergreen planning tool. The databases that have been compiled for this study are attached as Appendices to provide complete references for the study results. The Appendices in this report include:

- Appendix A — Residential Customer Model
- Appendix B — Economic and Demographic Database
- Appendix C — Historic and Projected Annual and Seasonal System Data
- Appendix D — Monthly Peaks and Energy

1.3 Data Resources

Projections of electric loads require substantial data from numerous sources. In addition to the internal system data provided by EED, this study relied heavily on the following third-party data resources.

Economic and Demographic Data

Woods and Poole Economics, Inc., Complete Economic and Demographic Data Series (CEDDS), January 2003.

National Planning Association, Regional Economic Projection Series (REPS), October 2002.

U.S. Department of Energy, Energy Information Administration (DOE-EIA), Annual Energy Outlook 2003.

U.S. Department of Energy, Energy Information Administration, State Energy Price and Expenditure Report, 1997.

Weather Data

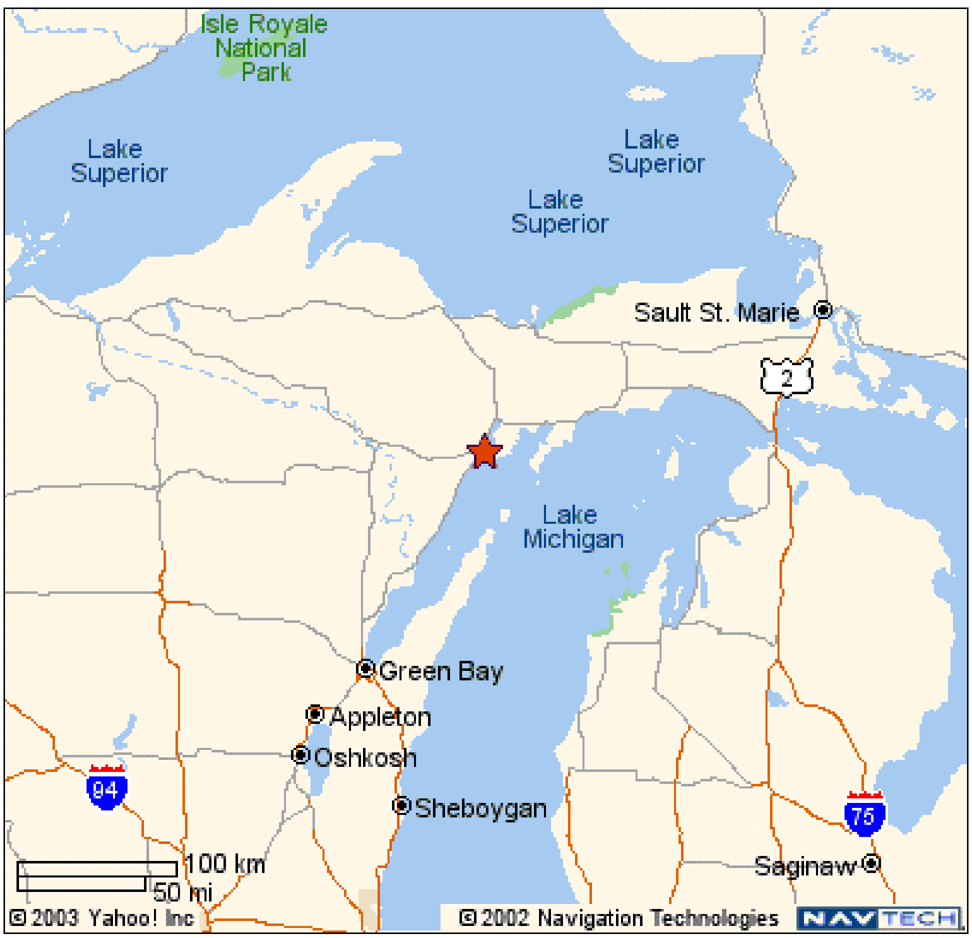
Midwestern Regional Climate Center (MRCC) Midwestern Climate Information System (MICIS) on-line data service.

2.0 LOCATION AND REGIONAL TRENDS

2.1 Location

Escanaba is the second largest city in the Upper Peninsula of Michigan and is located in Delta County about 110 miles northeast of Green Bay, Wisconsin. The population in 2000 was 13,140. Escanaba's economy is driven by taconite and iron ore shipping; manufacturing of wood and paper products, auto engine components, and packaging materials; its role as a wholesale and retail trade center, and tourism. The location on Bay De Noc provides critical access to Great Lakes shipping routes as well as the basis for fishing and water sports. More than half of Delta County is contained in the Hiawatha National forest.

Figure 2.1 Escanaba Location



2.2 Demographics and Economics

Growth in Escanaba reflects both local and county population, income, and employment trends. The retail trade area for the City is approximately 75 miles and contains about 30,000 residents. The wholesale trade area extends to about 200 miles and has a population of about 450,000. As shown in Table 2.1, Delta County population growth over the past decade has been very modest and much slower than for the state of Michigan. However, the County has grown faster than the City of Escanaba, which lost population at an annual rate of about 0.4 percent between 1990 and 2000.

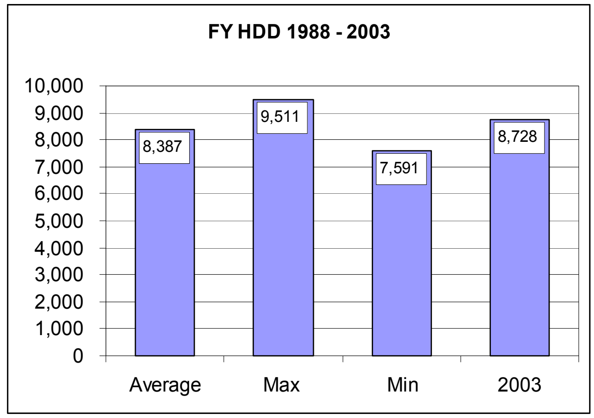
Despite the loss of population, per capita income growth in Delta County has been faster than for Michigan. By 2002, Delta County incomes were about 80 percent of the statewide average compared to 1990 when they were about 77.5 percent of the statewide figure. Employment trends show manufacturing in Delta County with a declining share of the total while service employment has grown relatively rapidly.

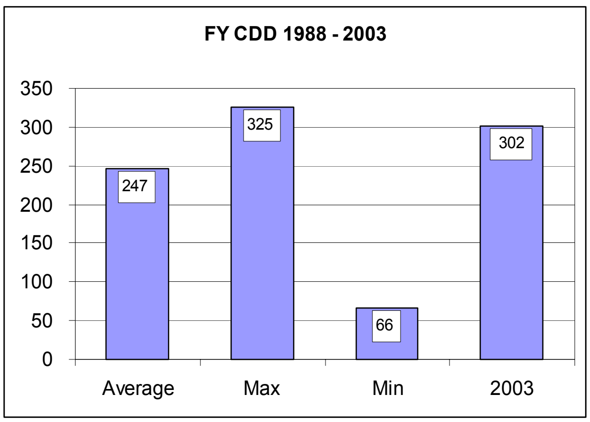
Table 2.1 Population, Income, Employment Trends

Population	1990	1995	2000	2002	1990-2000	1995-2000	1990-2002
Michigan	9,311,319	9,676,211	9,956,115	10,069,641	0.7%	0.6%	0.7%
Delta County	37,849	38,517	38,565	38,664	0.2%	0.0%	0.2%
Escanaba	13,663	13,596	13,140		-0.4%	-0.7%	
Real Per Capita Income							
Michigan	22,212	24,448	27,111	27,753	2.0%	2.1%	1.9%
Delta County	17,216	19,037	21,659	22,310	2.3%	2.6%	2.2%
Manufacturing Emp %							
Michigan	19.9%	19.3%	17.8%	17.5%	-1.1%	-1.7%	-1.1%
Delta County	19.1%	16.1%	16.8%	16.6%	-1.3%	0.8%	-1.2%
Service Employment %							
Michigan	26.7%	28.5%	30.2%	30.7%	1.3%	1.2%	1.2%
Delta County	22.8%	23.2%	27.2%	27.8%	1.8%	3.3%	1.6%

2.3 Weather

Winters in Escanaba are cold with annual heating degree-days averaging 8,387 from FY1988 through FY2003. The 2003 winter was 4.0 percent colder than normal with heating degree-days of 8,728. From 1988 through 2003, heating degree-days have ranged from 7,591 in FY1998 to 9,511 in FY1996.



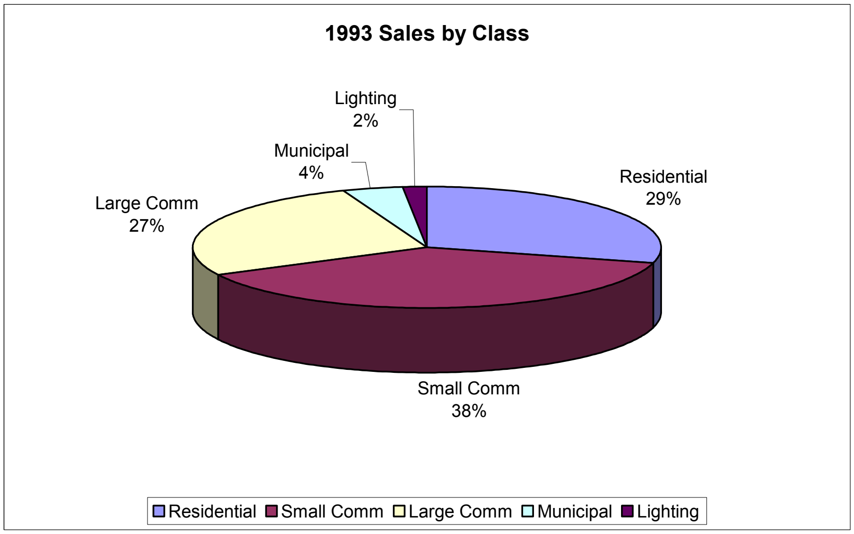


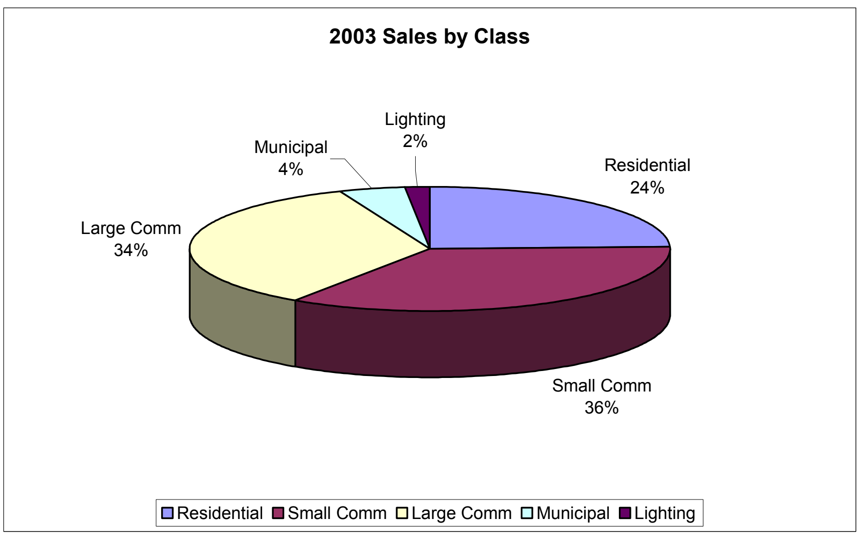
Summers in the service area are mild with average annual cooling degree-days of 247. The summer of 2003 was warmer than average, with 302 cooling degree-days. From 1988 to 2003, cooling degree-days have ranged from 66 in FY1993 to 325 in FY1999. Weather data are from Escanaba except for those years when Escanaba did not report. For those years Cornell weather data has been used.

2.4 Escanaba Electric Department (EED) Sales By Class

Municipal electric systems typically have sales that are roughly equally split among the residential, and commercial/industrial classes. As shown in Figure 2.2, Escanaba approximated this norm in 1993 with an additional six percent of sales going to municipal loads and to street lighting. Over the last decade, however, commercial and industrial sales growth has been much stronger than for the residential class. By 2003, residential sales accounted for less than twenty-five percent of the total. Municipal and lighting sales have retained a constant share. The most dramatic growth has been in sales to the large power class. Of the total sales to the 21 large power customers in 2003, approximately 60.0 percent were to five loads including an auto parts manufacturer, an ore dock, a hospital, a college and a food store.

Figure 2.2 EED Sales by Class 1993, 2003





3.0 THE RESIDENTIAL CLASS

3.1 General

The EED residential class accounted for 24 percent of total sales in 2003. EED accounts separately for space heating, water heating and all other residential end uses, which are referred to as residential lighting. Space and water heating accounts have been declining while the number of general residential customers has grown slowly. Despite the decreases in City population, the number of households served has increased as the number of persons per household has declined. This section presents separate projections of the number of residential customers and annual energy use per customer, which are then multiplied to forecast total residential energy sales. Forecasts have been developed for total residential customers and use per customer rather than for the separate residential subclasses.

3.2 Residential Customers

PSE maintains population historic and forecast databases at the county level from Woods & Poole Economics and from the National Planning Association that provide useful drivers in forecasting EED residential customers. The linkage between county population and the households served by EED can be seen in the following multiplicative equation:

$$CUSTEED/POPCO=A*B*C=HUEED/HUCO*HUCO/POPCO*CUSTEED/HUEED$$

where:

CUSTEED	=	Total residential customers served by EED
POPCO	=	Delta county population
HUEED	=	Households served by EED
HUCO	=	Delta county households

The customer-population ratio (CUSTEED/POPCO) can then be multiplied by the county population forecasts to obtain the desired forecast of total EED residential customers. The first multiplicative factor (A) represents the Escanaba share of county households, which has declined slowly over the past two decades. The second factor (B) is the inverse of persons per household in the county. This factor has increased in the past as family sizes have declined, the population has aged, and the number of single-person households has increased. This factor is expected to increase somewhat in the future but more slowly than in the past. The final factor (C) captures the ratio of total EED residential customers to the number of households served. This can be estimated by dividing the total residential customers by the number of lighting (general) residential customers. This factor has fallen in the past as the number of pure electric space and water-heating customers has declined.

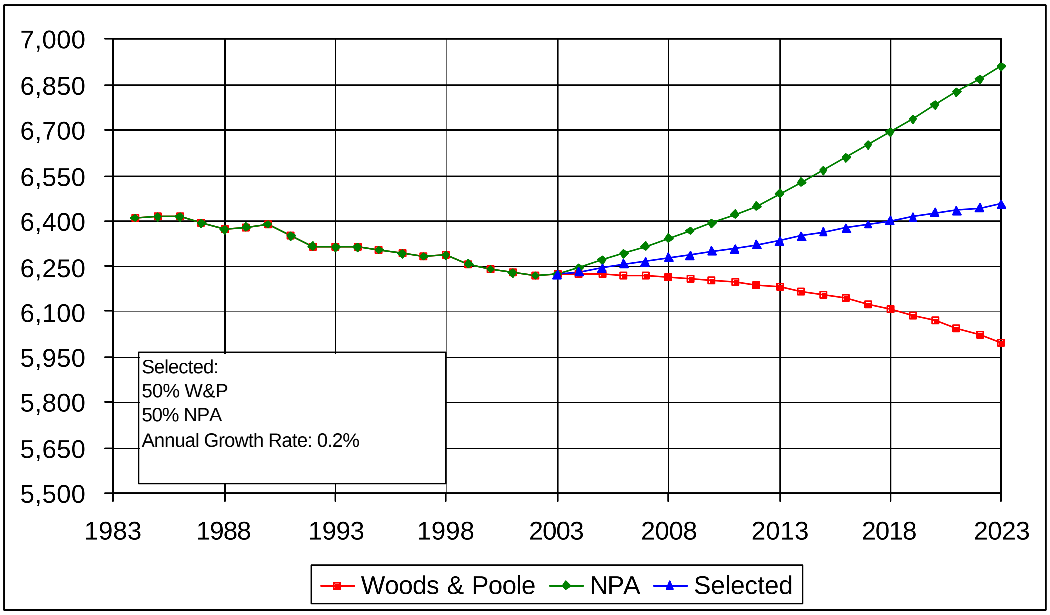
The full year-by-year development of the residential forecast is provided in Appendix A with the key results summarized at five-year intervals in Table 3.1. Figure 3.1 compares the alternative forecasts graphically.

Table 3.1 EED Residential Customers

Woods & Poole						
FY Ending	custeed/popco	hueed/huco	huco/popco	custeed/hueed	popco	custeed
1988	0.1695	40.4%	0.3763	1.11	37,587	6,370
1993	0.1644	38.8%	0.3910	1.08	38,375	6,310
1998	0.1628	37.8%	0.4062	1.06	38,598	6,285
2003	0.1607	37.0%	0.4157	1.05	38,716	6,221
2008	0.1589	36.1%	0.4208	1.05	39,108	6,214
2013	0.1562	35.3%	0.4236	1.05	39,567	6,180
2018	0.1522	34.4%	0.4231	1.05	40,134	6,109
2023	0.1472	33.6%	0.4196	1.05	40,757	6,000
National Planning Association						
FY Ending	custeed/popco	hueed/huco	huco/popco	custeed/hueed	popco	custeed
1988	0.1695	40.0%	0.3803	1.11	37,590	6,370
1993	0.1644	38.5%	0.3935	1.08	38,380	6,310
1998	0.1628	37.8%	0.4060	1.06	38,600	6,285
2003	0.1596	36.8%	0.4149	1.05	38,980	6,221
2008	0.1571	35.8%	0.4200	1.05	40,360	6,341
2013	0.1548	34.8%	0.4258	1.05	41,910	6,487
2018	0.1533	33.8%	0.4344	1.05	43,650	6,692
2023	0.1517	32.7%	0.4430	1.05	45,540	6,906

The alternative residential customer forecasts are shown in the final column. The difference in Delta County population forecasts between W&P and NPA is nearly 12 percent by 2023, which implies substantially different residential customer forecasts. Figure 3.1 shows the alternate forecasts and a weighted average result based on equal weights for each. It should be noted that these forecasts assume that space heating and water heating customers will retain their proportionate shares of the total at 2003 levels. If these shares continue to decline as historic rates, both of the residential customer forecasts would be lower than shown here. PSE recommends that EED use equal weights to define the selected residential customer forecast for this study. On that basis, residential customers will increase by about 0.2 percent or an average of 11.6 customers per year over the next two decades.

Figure 3.1 Residential Customer Forecasts



3.3 Energy Use Per Residential Customer

Excluding weather-related fluctuations, average energy use per EED residential customer has been steadily increasing for the last twenty years. Use per customer has grown from 4,464 kWh in 1984 to 5,794 kWh in 2003[1]. The long-term growth of use per customer has occurred despite the loss of some space and water heating load and declining occupancy of households as an increasing share of the population is employed outside the home. Contributing factors to the slow but steady growth have been continuing decreases in the real price of electricity and continuing increases in real per capita income. Most utilities in the upper Midwest have experienced substantial growth in the saturation of central air conditioning in recent years.

[1] It should be noted that the 2003 figure was well above the historic trend line mostly because heating degree-days were abnormally high for the FY ending in 2003.

While this may also have occurred in Escanaba, the total impact on electric sales would be rather small since there are so few cooling degree-days in this area.

An econometric model has been developed to quantify the influence of the key growth factors on use per residential customer. Econometric models have a demonstrable capability to explain observed historic variations in energy use and are designed to capture the impacts of demographic, economic, and weather variables. The EED model relates average annual energy use per residential customer to heating degree-days, the real (inflation adjusted) price of electricity[2], real per capita income, and the employment-population ratio. The number of heating degree-days influences electric use for space and water heating. Electric prices influence both the intensity with which customers use existing electric appliances and their decisions in purchasing new appliances when fuels and efficiencies are options. Real per capita income measures the capacity of residents to purchase new electric appliances and to add to the size of the average home. The employment-population ratio is a proxy for occupancy patterns of households. As this ratio rises, there are more hours per day when homes are not occupied because all of the residents are at work. The selected equation for residential use per customer is summarized in Table 3.2.

Table 3.2 Residential Econometric Model

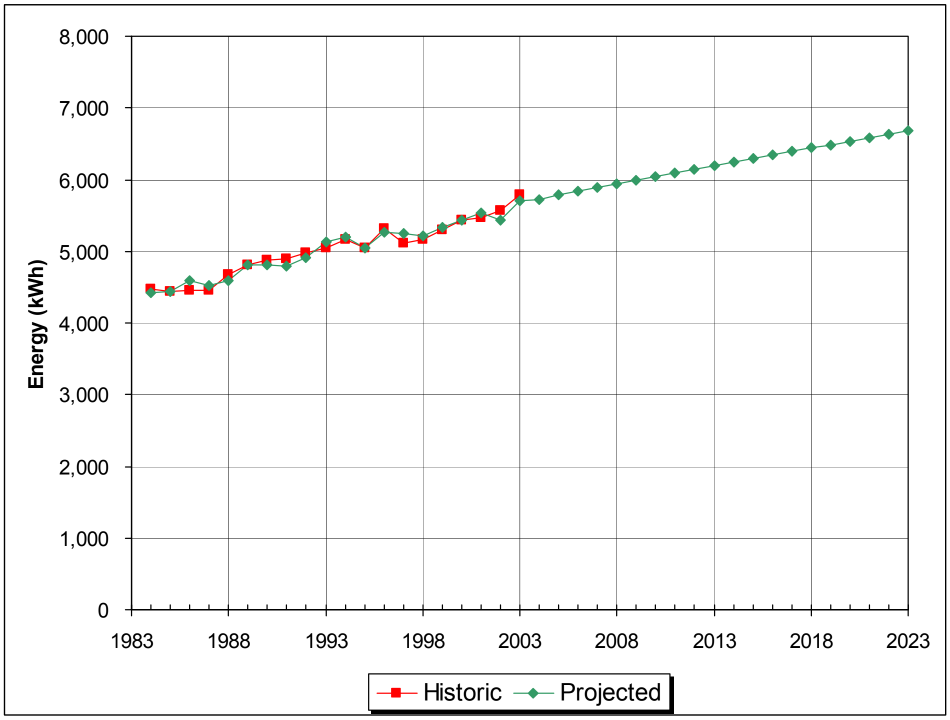
Dependent Variable: Residential Use per Customer Form: Log-log Sample(adjusted): 1984 2003 Included observations: 20 after adjusting endpoints				
Variable		Coefficient	t-Statistic	
Constant		2.529	2.269	
Heating Degree-Days		0.174	2.475	
Real Electric Price (03$)		-0.330	-3.461	
Real Per Capita Income NPA		0.343	4.268	
Employment/Population NPA		-0.277	-1.956	
R-squared	0.962	Mean dependent var		8.518
S.E. of regression	0.017	S.D. dependent var		0.078
Durbin-Watson stat	1.557	F-statistic		94.07

The selected equation has tracked historic experience quite well in terms of both levels and turning points. Figure 3.2 shows the selected equation's ability to capture historic energy use per

[2] Electric prices in this context refer to average revenue per kWh sold. They are converted to real terms using a personal consumption expenditure deflator provided by Woods and Poole.

residential customer and presents the current projection. This forecast assumes that the EED residential electric price will increase by just 2.0 percent per year over the forecast horizon. An increase of 1.0 percent in the real price in a given year would reduce usage by 0.34 percent in that year. The forecast also assumes normal weather for all future years.

Figure 3.2 EED Energy Use per Residential Customer



Residential energy use per customer projections are summarized numerically in Table 3.3. The decrease in usage from 2003 to 2004 reflects the assumption of normal weather in 2004 compared to the rather cold winter in FY2003. Energy use per customer increases at an average annual rate of 0.7 percent from 2003 to 2023.

Table 3.3 Residential Energy Use per Customer

FY Ending	Actual	Estimated	Error
1988	4,667	4,598	-1.5%
1993	5,048	5,128	1.6%
1998	5,158	5,218	1.2%
2003	5,794	5,707	-1.5%
2008		5,946	
2013		6,193	
2018		6,439	
2023		6,687	
Growth Rates			
1988 -2003	1.5%	1.5%	
1993-2003	1.4%	1.1%	
1998-2003	2.4%	1.8%	
2003-2008		0.5%	
2003-2013		0.7%	
2003-2018		0.7%	
2003-2023		0.7%	

Figure 3.3 presents illustrative graphs of the independent variables used in the econometric equation to show the influences on electric usage captured by the model. All variables enter the model with expected signs, plausible elasticities, and acceptable t-statistics. Trends in the model's independent variables displayed in Figure 3.3 are explained as follows:

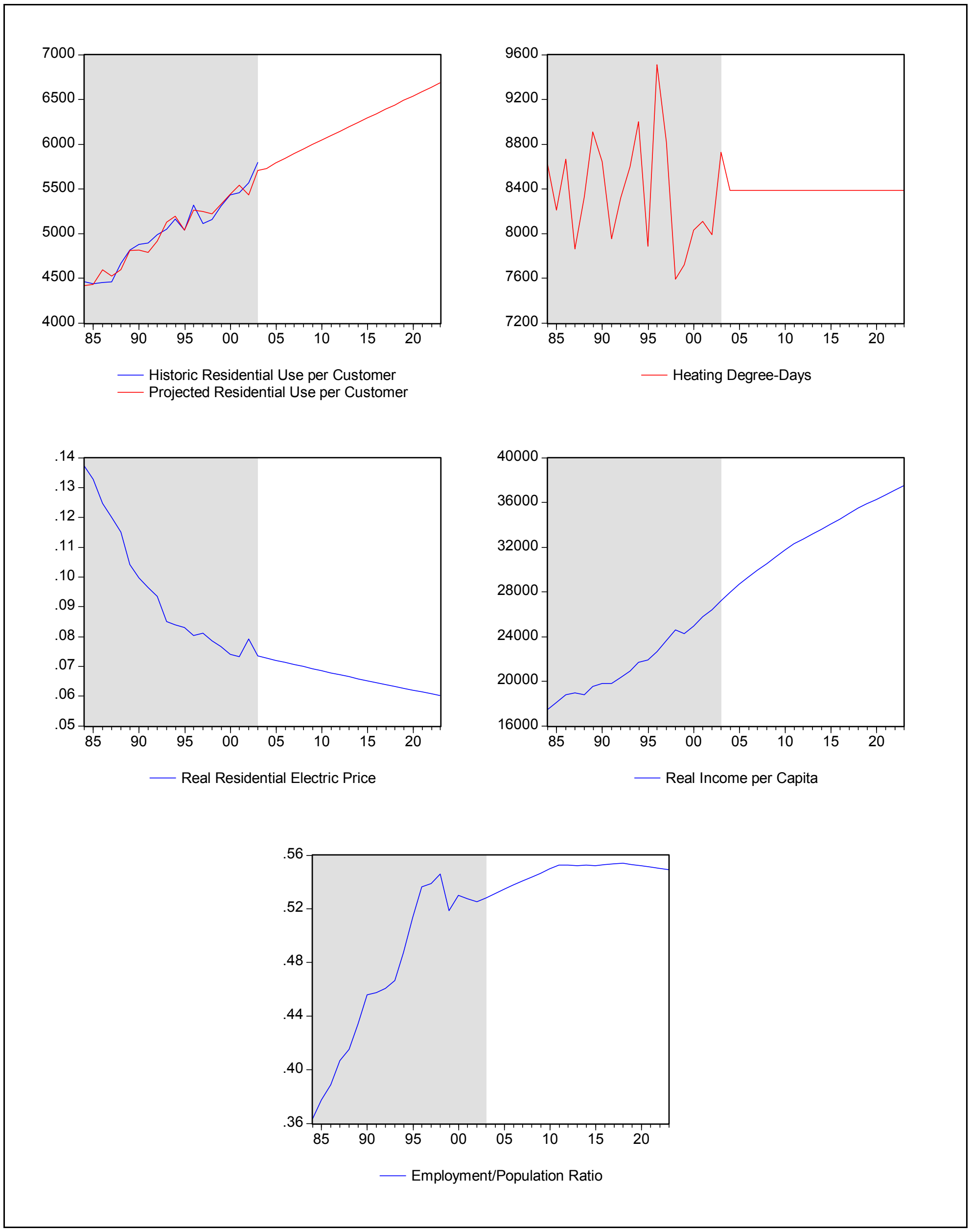
Heating Degree-Days - Heating degree-days are a proxy for the amount of electricity used for space heating, furnace fans and other incremental use related to cold weather. The extremely cold winters of 1996 and 1997 followed by abnormally mild winters through 2002 are especially evident in Figure 3.3. The impact of extreme winter weather on average usage is also evident. The projection of heating degree-days is based on the historic average figure over the 1988 to 2003 period.

Real Electric Price (03$) – The real price of electricity for EED residential customers has fallen steeply through the mid 1990's and has continued to fall at more moderate rates except for one blip in 2002. Typically this reflects stability in the total electric plant with per unit fixed costs declining because of increasing sales. The future forecast of electric prices will depend on the power supply and distribution plant requirements in the future. It is unlikely that the steep declines of the past will continue. The illustrative forecast provided here assumes real price decreases of 1.0 percent per year, which is roughly equivalent to nominal price increases of 2.0 percent per year.

Real Per Capita Income (03$) – Real per capita income forecasts for Delta County have been taken from the NPA series, which is somewhat more optimistic than the Woods & Poole equivalent. The NPA forecast growth rates are 2.0 percent per year over the next ten years and 1.6 percent per year through 2023 compared to the historic growth rate of 2.7 percent over the 1993-2003 period. It is important to recognize that the rapid economic growth experienced in the 1990's is unlikely to be sustained over the next two decades.

Employment-Population Ratio – Slowing economic growth is also reflected in the employment-population ratio, which rose sharply in the 1985 to 1998 period. Since 1998, this ratio has been rather stable and little growth is expected in the future.

Figure 3.3 Residential Econometric Model Inputs



We can summarize the influence of the key growth factors on residential use per customer as follows:

- The return of normal heating degree-days in FYE 2004 will tend to reduce the use per customer figure compared to the cold year of FYE 2003.

- Moderation of the rates of decrease in residential electric prices will tend to dampen growth rates of use per customer compared to the past.

- Lower future growth rates of per capita income will also tend to dampen increases in future residential usage figures.

- Lower employment-population ratios will tend to increase the time of occupancy of the households that EED serves, which will tend to increase electric usage.

- In total, future growth in use per customer is expected to be slower than in the past since the predominant future trends suggest dampened growth trajectories. Any comparison of historic and future growth rates must also recognize that 2003 usage was high because of an abnormally cold winter.

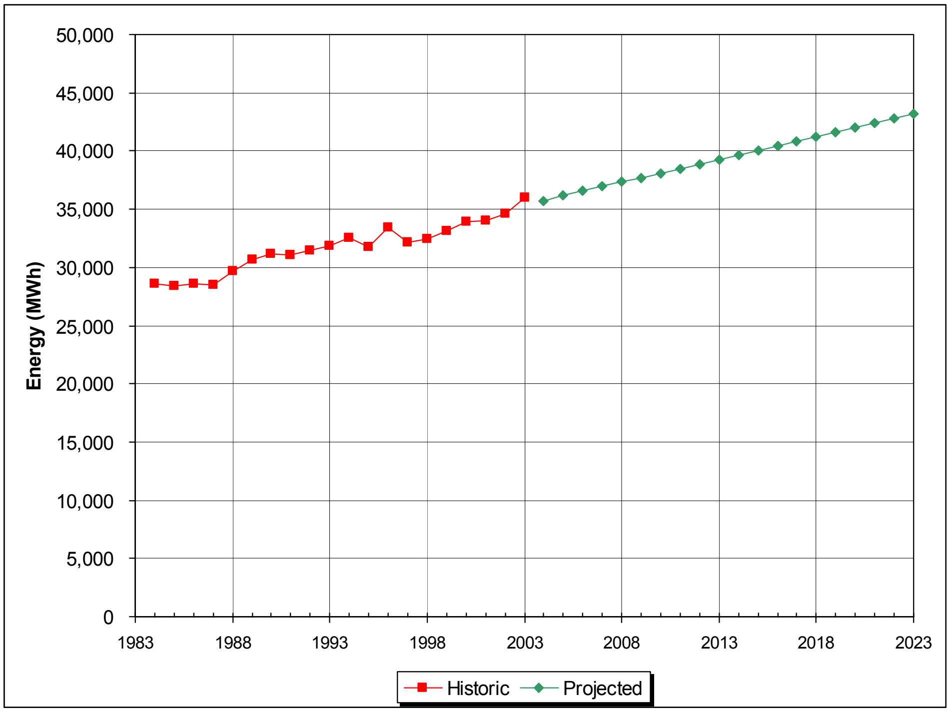
3.4 Residential Energy Sales

Projections of energy sales to the residential class are the product of the number of customers and the energy use per customer forecasts. Residential energy projections are summarized in Table 3.4 and in Figure 3.3. Total residential energy sales are projected to increase from 36,042 MWh in 2003 to 43,155 MWh in 2023 at an average annual rate of 0.9 percent.

Table 3.4 Residential Energy Projections

FY Ending	Customers	Usage	Sales (MWh)
1988	6,370	4,667	29,730
1993	6,310	5,048	31,850
1998	6,285	5,158	32,416
2003	6,221	5,794	36,042
2008	6,278	5,946	37,330
2013	6,333	6,193	39,222
2018	6,401	6,439	41,213
2023	6,453	6,687	43,155
Growth Rates			
1988 -2003	-0.2%	1.5%	1.3%
1993-2003	-0.1%	1.4%	1.2%
1998-2003	-0.2%	2.4%	2.1%
2003-2008	0.2%	0.5%	0.7%
2003-2013	0.2%	0.7%	0.8%
2003-2018	0.2%	0.7%	0.9%
2003-2023	0.2%	0.7%	0.9%

Figure 3.4 Escanaba Residential Energy Sales



4.0 THE COMMERCIAL AND INDUSTRIAL CLASSES

4.1 General

In 2003, EED served 1,144 commercial and industrial (C&I) accounts that comprised 70.0 percent of total electric sales. The C&I accounts are classified into two revenue classes: Commercial light class and large power class. There were 1,123 small C&I accounts in the commercial light class that used 51,748 MWh in FY2003, while the large power class was composed of 21 large C&I accounts whose total usage was 50,456 MWh. The commercial light class has been growing modestly over the last five years with the continuous growth in service employment. Energy sales to the large power class were stagnant with the depressed manufacturing sector economy between 1998 and 2002 but increased by more than 14 percent in 2003, mainly due to the expansion of one large C&I account. This section describes the forecast methods used and the results obtained for these two important classes.

4.2 Commercial Light Class Projections

The commercial light class includes a variety of small C&I accounts dominated by retail and service businesses. Energy sales to the small C&I class depend on changing economic conditions and weather patterns. The number of small C&I customers and average energy use per customer are projected separately, and are then multiplied to calculate total energy sales forecast for this class.

4.2.1 Commercial Light Customers

The number of commercial light customers increased from 1,077 to 1,123 over the past five years at an average annual rate of 0.8 percent. An econometric model has been developed to forecast the number of small C&I customers. The selected model relates the number of small C&I customers to real (inflation adjusted) income per capita and total employment in the trade area[3]. As the trade area income per person increases, residents will demand additional goods and services, causing growth in area retail and service sectors. More businesses will locate in the area to serve local homes and will create additional small C&I accounts for EED. Increase in total employment is also an

[3] The retail trade area for Escanaba is assumed to be Delta County for this analysis.

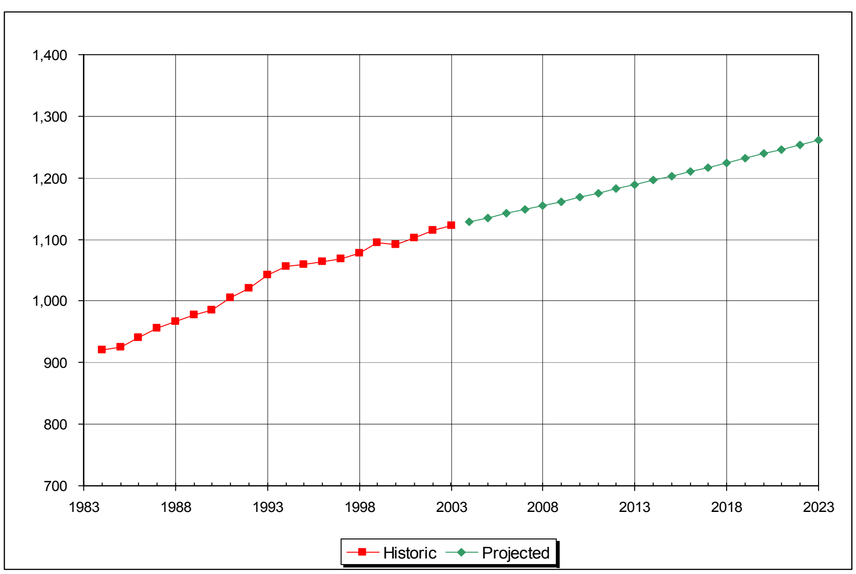
indicator of the local economic growth and the increase in number of local business establishments. As the number of local business establishments increases, the number of commercial light accounts will also increase. The selected econometric model is presented in Table 4.1.

Table 4.1 Commercial Light Customer Econometric Model

Dependent Variable: Commercial Light Customers Form: Log-Log Sample: 1984 2003			
Variable	Coefficient	t-Statistic	
Constant	2.196	9.919	
Per Capita Income (03$)	0.234	3.169	
Total Employment	0.246	3.592	
R-squared	0.967	Mean dependent var	6.935
S.E. of regression	0.012	S.D. dependent var	0.064
Durbin-Watson stat	1.064	F-statistic	250.5

Using this equation and income and employment forecasts from Woods & Poole, the number of commercial light customers is projected to increase at an average annual rate of 0.6 percent over the next twenty years. This is slightly lower than the growth rate of 0.8 percent experienced over the past five years, reflecting somewhat lower long-term expectations of future economic growth. The forecast results are presented in Figure 4.1 and in Table 4.3.

Figure 4.1 Escanaba Commercial Light Customer Forecast



4.2.2 Commercial Light Energy Use Per Customer

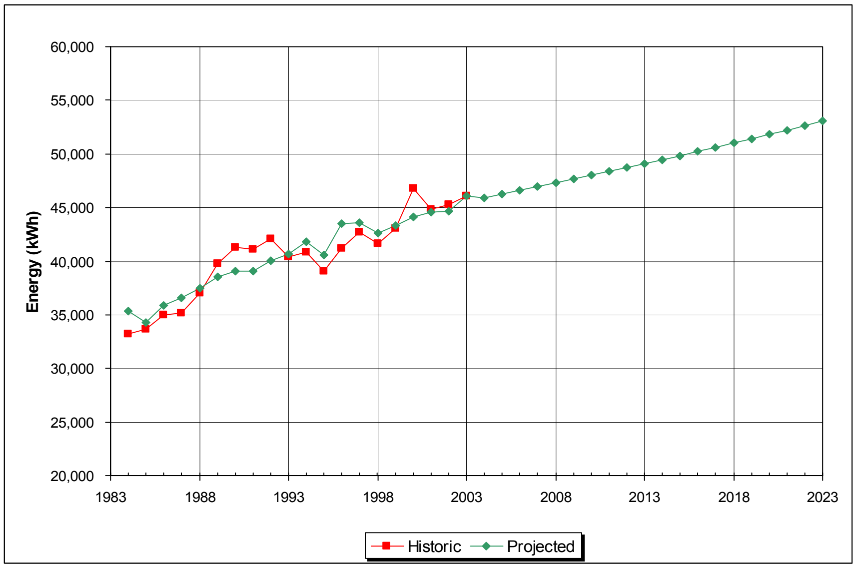
The average commercial light customer used 46,080 kWh in 2003. Average energy use for small C&I loads is generally more erratic than residential energy use due to the heterogeneity of small businesses.

An econometric model has been developed to forecast average energy use for the small C&I customers. The selected model relates the average energy use to trade area service employment and to heating degree-days. Increase in service employment indicates expansion of small commercial businesses and therefore increase in energy use of those businesses. Furthermore, new service related loads, also indicated by increase in service employment, tend to be more energy-intensive than older businesses and induce an increase in average energy use for the small C&I class. The econometric model is presented in Table 4.2 and the forecast results are presented in Figure 4.2.

Table 4.2 Commercial Light kWh per Customer Econometric Model

Dependent Variable: Commercial Light Use per Customer			
Form: Log-Log			
Sample: 1985 2003			
Included observations: 19			
Variable	Coefficient	t-Statistic	
Constant	4.878	3.225	
Heating Degree-Days	0.272	2.729	
Service Employment	0.391	2.985	
Auto-Regressive (1)	0.678	3.719	
R-squared	0.912	Mean dependent var	10.615
S.E. of regression	0.030	S.D. dependent var	0.093
Durbin-Watson stat	1.751	F-statistic	51.828
Inverted AR Roots	.68		

Figure 4.2 Commercial Light kWh per Customer



Trends in the independent variables that drive the C&I customer and energy forecasts are discussed in the following paragraphs. The dependent and independent variables are presented in Figure 4.3 and are described as follows:

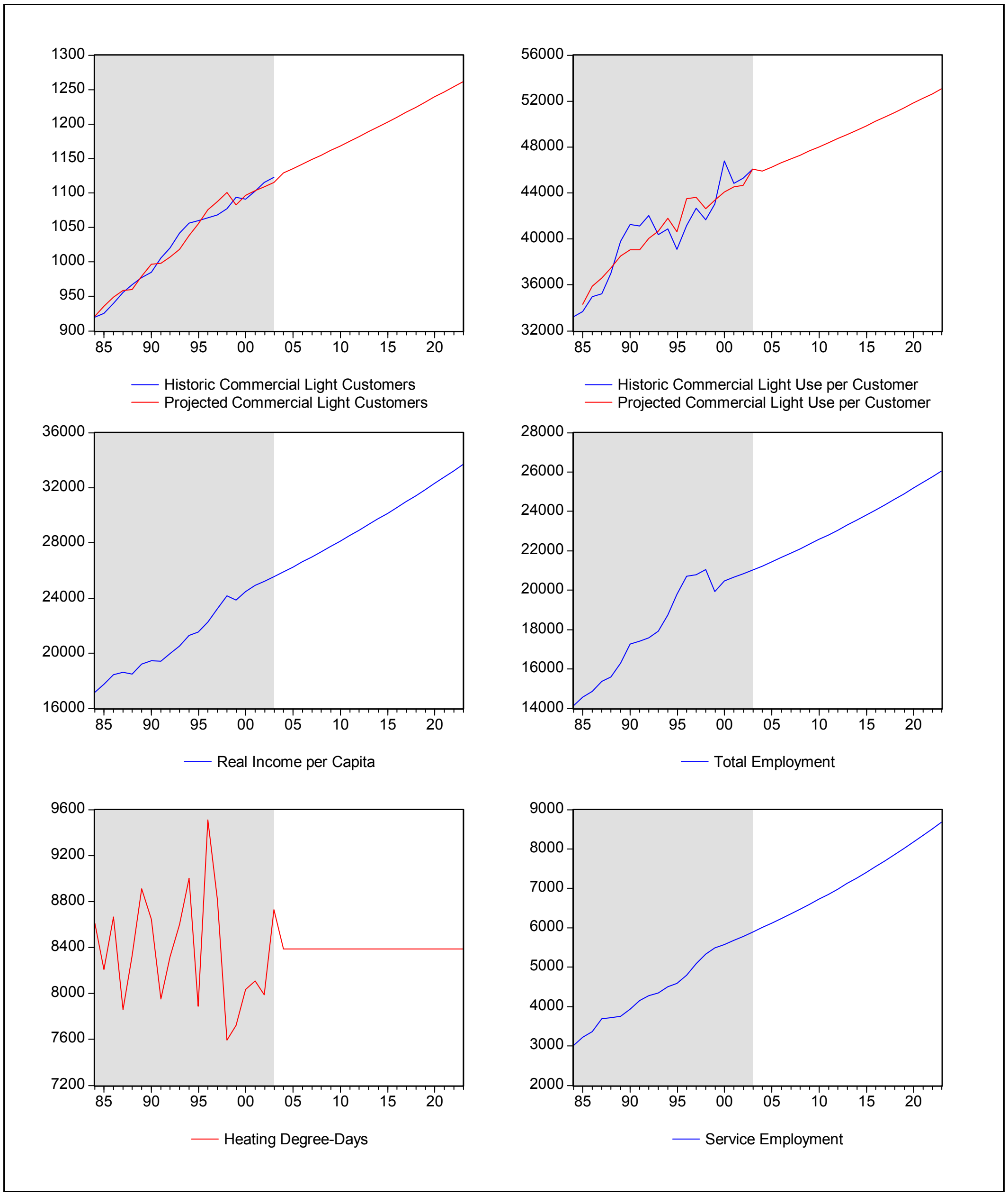
Real Income Per Capita – Per capita income net of inflation rose rapidly in the 1990's with continued national economic prosperity. Following a slight drop in 1999, growth continued, but on a much lower trajectory. The annual growth rate of 2.2 percent from 1993 to 2003 fell to 1.1 percent for 1998 to 2003. The Woods & Poole forecasts throughout the forecast period are for renewed expansion at annual rates of 1.4 percent.

Total Employment – Total employment for Delta County mirrors the growth trends of per capital income. For the past decade, the annual growth rate was 1.6 percent but no growth occurred from 1998 through 2003. The Woods & Poole forecast shows future growth accelerating to rates of 1.0 percent for the next 10 years and 1.1 percent over the next two decades.

Service Employment – Service employment has been less cyclic than total employment. The ten-year historic growth rate of 3.1 percent per year fell slightly to 2.0 percent for the 1998 to 2003 period. The Woods & Poole forecast sees continued growth at 2.0 percent per year for the next twenty years.

Heating Degree-Days – Heating degree-days are a proxy for the amount of electricity used for space heating, furnace fans and other incremental use related to cold weather. A positive correlation is anticipated between Commercial Light per customer usage and heating degree-days. The projections of heating degree-days are based on historic average figures over the 1988 to 2003 period.

Figure 4.3 Commercial Light Econometric Model Inputs



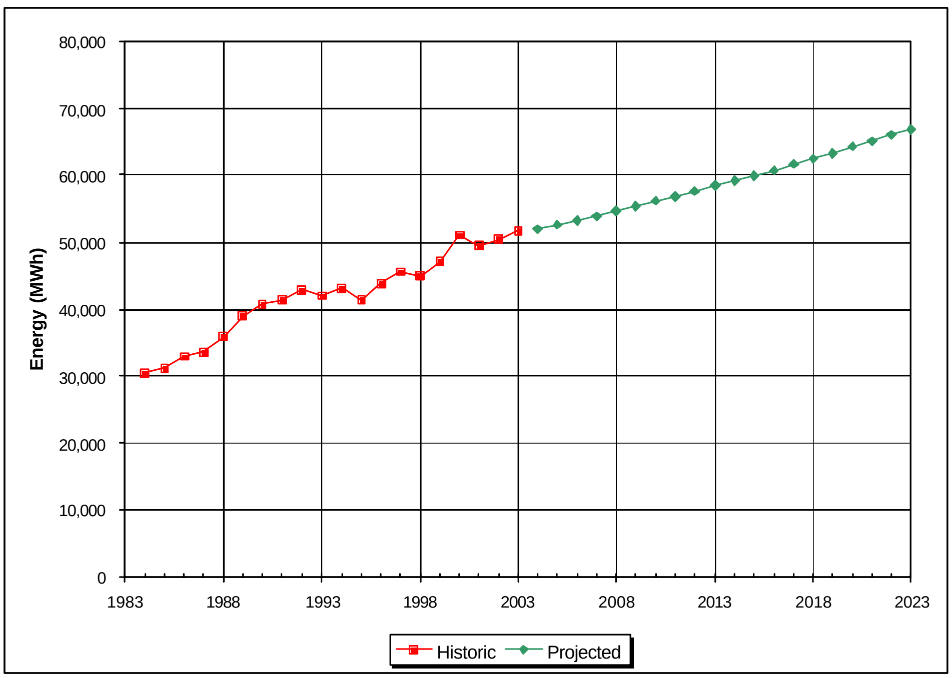
4.2.3 Commercial Light Energy Sales

The forecast of total energy sales to the commercial light class is the product of the customer and energy use per customer forecasts presented in this section. Sales to the small C&I class were 51,748 MWh in 2003 and are expected to increase at an average rate of 1.3 percent per year to 66,929 MWh in 2023. The commercial light energy forecast is summarized in Table 4.3 and Figure 4.4.

Table 4.3 Commercial Light Forecasts

Fiscal Year Ending June	Customers	kWh per Customer	Energy Sales (MWh)
1993	1,042	40,390	42,087
1998	1,077	41,684	44,894
2003	1,123	46,080	51,748
2008	1,155	47,296	54,618
2013	1,189	49,093	58,359
2018	1,224	51,007	62,443
2023	1,262	53,047	66,929
Annual Growth Rates:			
1993-2003	0.8%	1.3%	2.1%
1998-2003	0.8%	2.0%	2.9%
2003-2008	0.6%	0.5%	1.1%
2003-2013	0.6%	0.6%	1.2%
2003-2023	0.6%	0.7%	1.3%

Figure 4.4 Commercial Light Energy Sales



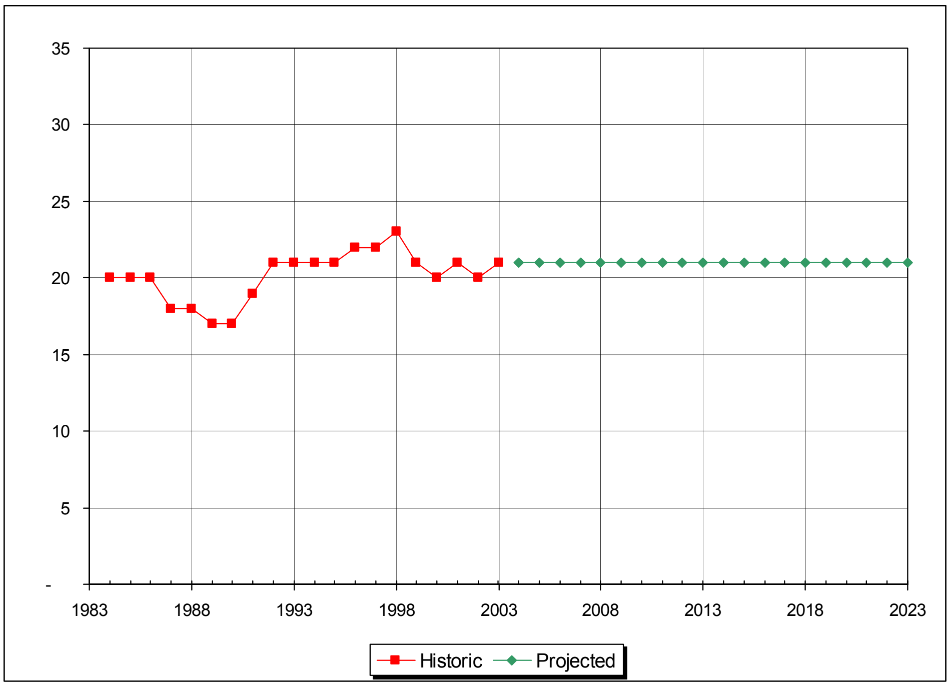
4.3 Large Power Class Projections

The large power class comprises 21 large C&I accounts dominated by large manufacturing facilities, school buildings, hospitals and large retail stores. Energy sales to the large C&I class depend mainly on changing economic conditions. The number of large power customers has been stable since 1998 and is not expected to change significantly. The total energy sales to those large C&I customers are projected by econometric modeling.

4.3.1 Large Power Customers

The number of large power customers has been stable at about 21 since 1991. Therefore, since there are no known changes in the foreseeable future, the projected number of large power customers is held constant at 21 over the next twenty years.

Figure 4.5 Escanaba Large Power Customers



4.3.2 Large Power Energy Sales

An econometric model has been developed to forecast total energy sales to the large C&I customers. The selected model relates the total large power energy sales to Delta County manufacturing employment and to an annual trend variable. A shift variable is used to capture the large expansion of a major load in 2003. An increase in manufacturing employment indicates expansion of large industrial manufacturing operations and therefore increased energy use by the large industrial class. An annual trend variable is included to track the combined effect of long-term trends of general economic conditions, industrial energy intensity and efficiency, fuel switches, etc. EMP, EED's largest industrial account, expanded their manufacturing operations substantially and thus increased their energy usage by more than 50 percent in 2003. As a consequence, the large power energy sales grew more than 14 percent in 2003. The shift variable that captures this change assumes that the expanded operations and usage will continue throughout the forecast period. The econometric model is presented in Table 4.4.

Table 4.4 Large Power Energy Sales Econometric Model

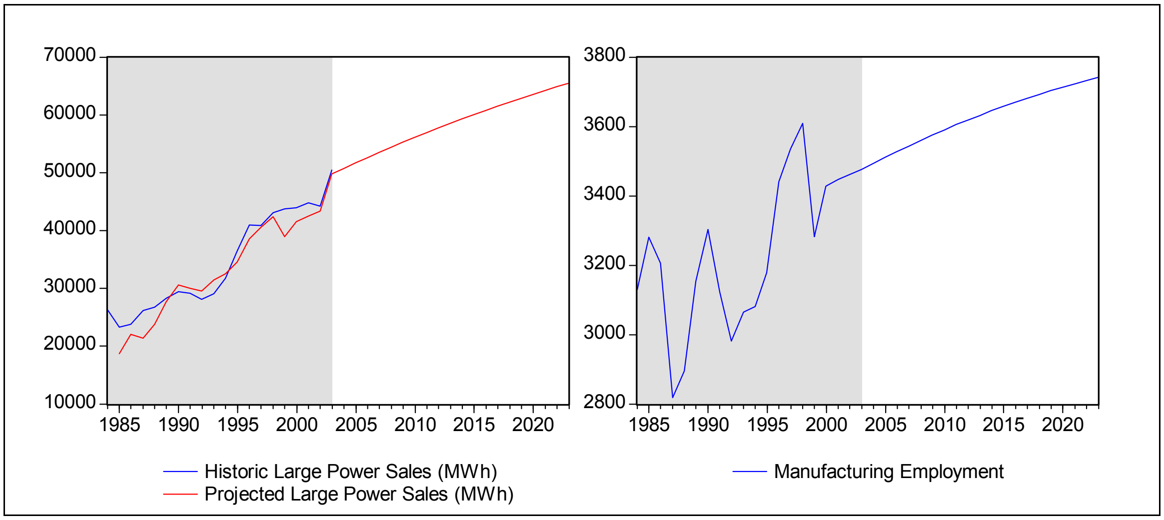
Dependent Variable: Large Power Sales			
Form: Log-log			
Sample: 1985 2003			
Included observations: 19			
Variable	Coefficient	t-Statistic	
Constant	7.906	3.529	
Manufacturing Employment	1.092	3.878	
Trend	0.269	8.997	
Dummy 2003-on	0.119	1.626	
R-squared	0.936	Mean dependent var	17.341
S.E. of regression	0.068	S.D. dependent var	0.247
Durbin-Watson stat	1.044	F-statistic	74.183

The independent variables that drive the large C&I energy sales forecasts are discussed in the following paragraphs. The dependent and independent variables are presented in Figure 4.5 and are described as follows:

Manufacturing Employment – Manufacturing employment for Delta County has been volatile over the last twenty years. The growth rate of 1.3 percent per year over the past decade fell to -0.7 percent for the last five years. This is common for relatively small areas with a number of large employers that compete in cyclic economic sectors. The Woods & Poole forecast is for modest growth at an annual rate of 0.4 percent over the next twenty years.

Annual Trend – The coefficient of the annual trend variable measures the net effect of general trends of economic conditions, industrial energy intensity and efficiency, fuel switches, etc. The positive coefficient of the variable indicates a long-term positive growth trend of the energy sales to large C&I customers.

Table 4.5 Large Power Econometric Model Inputs

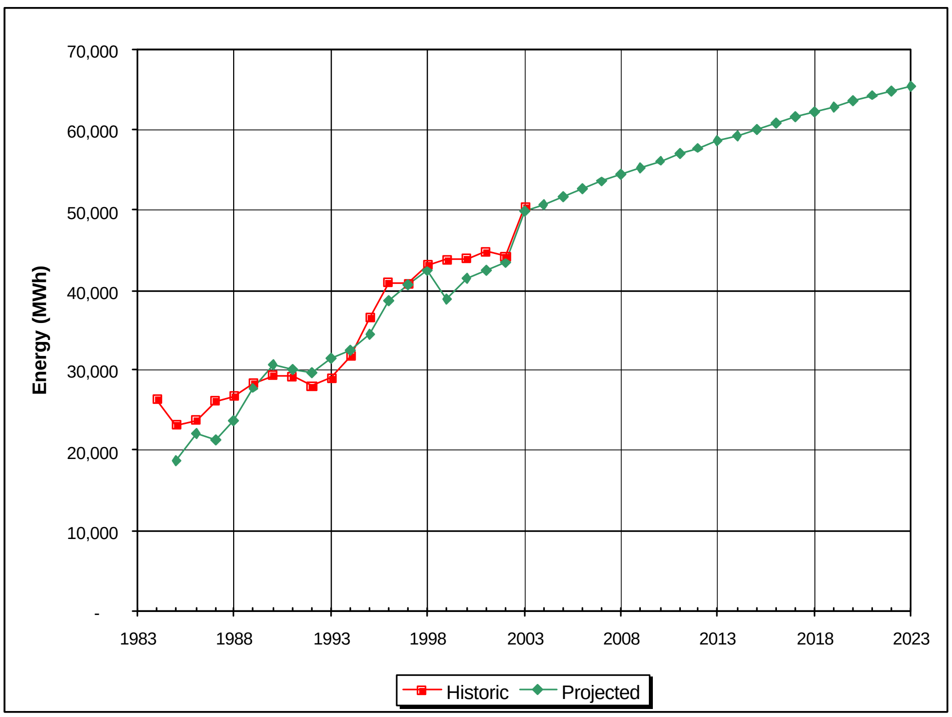


Sales to the large C&I class were 50,456 MWh in 2003 and are expected to increase at an average rate of 1.3 percent per year to 65,472 MWh in 2023. In 2003, sales to the top five large C&I accounts comprised about 60.0 percent of the total Large Power energy sales. The top five loads are EMP, Sault Ste Marie Bridge Company, St. Francis Hospital, Bay De Noc Community College and Super One Foods. According the most recent survey, three of those large C&I customers anticipate a steady growth of 1 to 2 percent per year for the next five years and two of them expect no growth. Thus, the econometric class sales forecast appears to be consistent with the expectations for these dominant large loads. This forecast would not accommodate service to any major new large power accounts locating in Escanaba. The large power forecast is summarized in Table 4.5 and Figure 4.6.

Table 4.6 Large Power Forecasts

Fiscal Year Ending June	Customers	kWh per Customer	Energy Sales (MWh)
1993	21	1,383,153	29,046
1998	23	1,871,458	43,044
2003	21	2,402,666	50,455
2008	21	2,590,559	54,408
2013	21	2,786,609	58,518
2018	21	2,961,388	62,189
2023	21	3,117,695	65,476
Annual Growth Rates:			
1993-2003	0.0%	5.7%	5.7%
1998-2003	-1.8%	5.1%	3.2%
2003-2008	0.0%	1.5%	1.5%
2003-2013	0.0%	1.5%	1.5%
2003-2023	0.0%	1.3%	1.3%

Figure 4.6 Large Power Energy Sales



5.0 OTHER CLASSES

5.1 General

EED has three additional small customer classes: municipal accounts, street lighting and the dusk to dawn class, which consists primarily of exterior lighting for residential and commercial accounts. The municipal class accounted for 4.0 percent of 2003 EED sales while the lighting classes accounted for 2.0 percent of EED sales. Since these classes are small, simple trending has been used to forecast them as explained in the rest of this section.

5.2 Municipal Class

EED served 105 municipal accounts in 2003. The number of accounts grew rapidly until 1999, with additions of ten new accounts per year from 1989 to 1999. Since 1999, municipal customers have been stable, ranging from 103 to 107. In the past five years, the average additions have been 2.4 per year. It is likely that municipal accounts will be added in the future. The forecast assumes modest expansion of two new municipal accounts per year.

Annual use per municipal account has been rather stable for the past decade with an average of 59,944 kWh and a range from 8.0 percent below to 13.0 percent above this average. The forecast of use per customer for 2004 has been set equal to the ten-year average figure. From 2005 on, annual increases have been assumed at a rate of 0.5 percent, which matches the historic growth rate from 1988 through 2003. Table 5.1 summarizes the municipal class forecast.

Table 5.1 Municipal Class Forecast

FYE	Customers	Use/Cust	Sales MWh
1988	52	58,103	3,021
1993	59	74,952	4,422
1998	93	60,368	5,614
2003	105	62,834	6,598
2008	115	61,208	7,039
2013	125	62,826	7,853
2018	135	64,487	8,706
2023	145	66,191	9,598
Annual Growth Rates			
1988-03	4.8%	0.5%	5.3%
1993-03	5.9%	-1.7%	4.1%
1998-03	2.5%	0.8%	3.3%
2003-08	1.8%	-0.5%	1.3%
2003-13	1.8%	0.0%	1.8%
2003-18	1.7%	0.2%	1.9%
2003-23	1.6%	0.3%	1.9%

5.3 Street Lighting and Dusk to Dawn

EED treats municipal street lighting as a single account that used 1,976 MWh in 2003. Lighting loads typically remain very stable unless there is an active program to replace old fixtures with higher efficiency lights. In the last five years, the average sales to this class were 1,980 MWh with a range of variations from 1.1 percent below to 0.5 percent above this average. The forecast for this class simply assumes that there will be a single customer using 1,980 MWh per year.

Dusk to dawn accounts have remained stable at 334 for the last three years. Use per customer has averaged 1,734 kWh per year over the last four years. Both customers and usage per customer are expected to remain at these levels over the forecast horizon.

6.0 TOTAL ENERGY REQUIREMENTS AND PEAK DEMANDS

6.1 General

Projections of energy sales to each customer class have been presented in previous sections of this report. This section combines those forecasts to calculate total energy sales and to develop the forecast of total energy requirements. Historically, total energy requirements have been estimated as total purchases plus generation less economy sales from 1994 through 2003. Prior to 1994, total energy requirements are estimated as total retail sales plus losses, which are estimated at 4.0 percent of the total energy requirement. Total energy requirement at the generator and/or purchased delivery point is a key planning parameter for power supply studies. In addition, power supply studies rely centrally on forecasts of future peak demands and the reserves necessary to assure that those peaks can be met reliably. This section also develops the forecasts of seasonal peak demands and the design loads for the power supply study.

6.2 Annual Energy Requirements

EED's total energy requirements are comprised of:

1. Retail sales
2. EED's own use
3. Distribution losses

Since EED does not separate own use and losses in their historic reporting, these two components have been combined here as well.

Figure 6.1 and Table 6.1 summarize sales histories and forecasts to each of EED's customer classes. As is evident in Figure 6.1, the commercial light and large power classes are expected to grow more rapidly than the residential class. Surveys of the major large power loads showed anticipated growth was typically in the 1.0 percent to 2.0 percent range for those that expect to grow. Other major loads expected usage to remain stable. Residential sales grow more slowly than in the past primarily because of slower growth in average usage per customer. Reported historic data for losses and own use are erratic and appear to be on the low side. For the forecast, losses and own use have been assumed equal to 4.0 percent of total energy requirements.

Energy sales are expected to increase from 147 GWh in 2003 to 188 GWh in 2023, which is an average annual growth rate of 1.2 percent. Total energy requirements are forecasted to increase from 150 GWh to 196 GWh in this same period, which represents average annual growth at a rate of 1.3 percent. Figure 6.2 provides a graphic comparison of historic and expected growth in total energy requirements for EED.

Figure 6.1 EED Energy Sales by Class

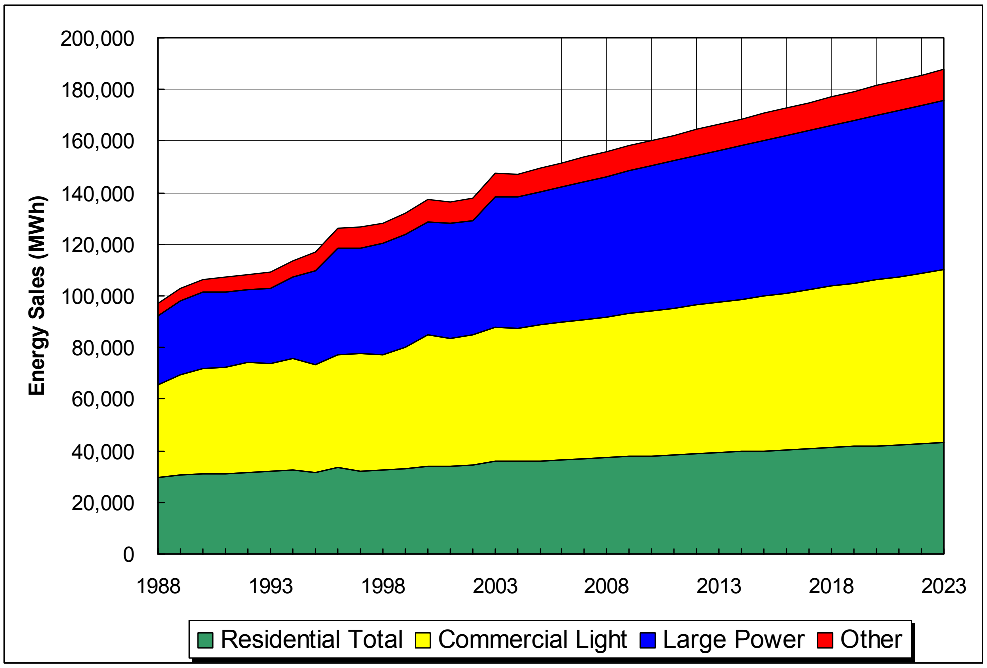
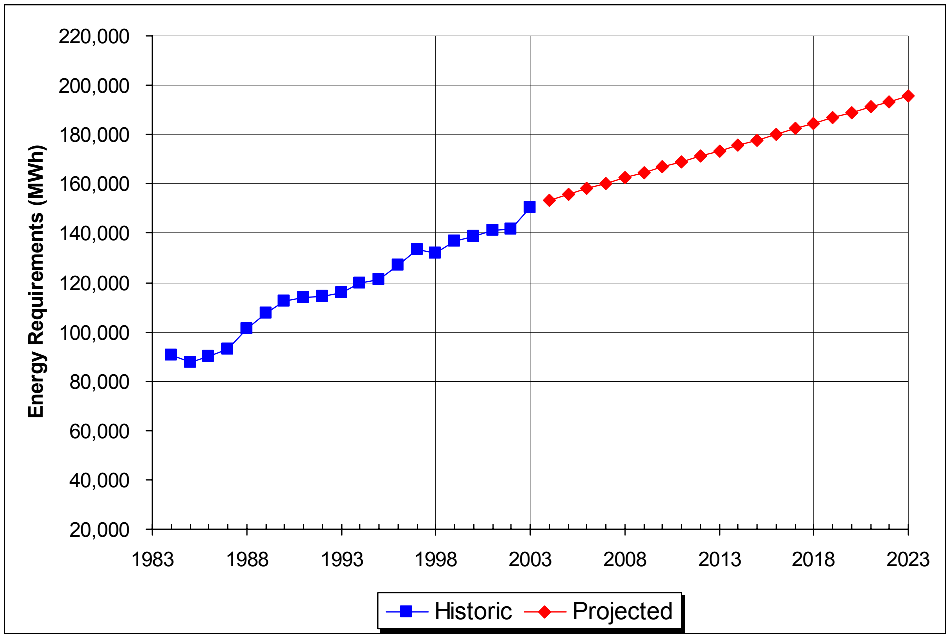


Table 6.1 EED Total Retail Sales and Energy Requirements (MWh)

FYE	Residential	Commercial	Lg Power	Other	Retail Sales	Losses	Total Reqrd
1988	29,730	35,797	26,776	4,958	97,260	4,052	101,312
1993	31,850	42,087	29,046	6,361	109,344	6,297	115,641
1998	32,416	44,894	43,044	7,953	128,306	3,680	131,986
2003	36,042	51,748	50,456	9,157	147,404	3,027	150,430
2008	37,330	54,618	54,402	9,599	155,949	6,498	162,447
2013	39,222	58,359	58,519	10,413	166,513	6,938	173,451
2018	41,213	62,443	62,189	11,265	177,110	7,380	184,490
2023	43,155	66,929	65,472	12,157	187,713	7,821	195,534
Annual Growth Rates							
1988-03	1.3%	2.5%	4.3%	4.2%	2.8%	-1.9%	2.7%
1993-03	1.2%	2.1%	5.7%	3.7%	3.0%	-7.1%	2.7%
1998-03	2.1%	2.9%	3.2%	2.9%	2.8%	-3.8%	2.7%
2003-08	0.7%	1.1%	1.5%	0.9%	1.1%	16.5%	1.5%
2003-13	0.8%	1.2%	1.5%	1.3%	1.2%	8.6%	1.4%
2003-18	0.9%	1.3%	1.4%	1.4%	1.2%	6.1%	1.4%
2003-23	0.9%	1.3%	1.3%	1.4%	1.2%	4.9%	1.3%

Figure 6.2 EED Total Energy Requirements



6.3 Seasonal Peak Demands

While total energy requirements are important for power supply planning, capacity decisions relate more directly to the total sources required to cover expected peak demands plus reserves. Since capacity prices in the upper Midwest vary widely between seasons, it is useful to recognize the peaks for both winter and summer seasons. Most probable power suppliers or purchasers for EED will be in either the Mid-Continent Area Power Pool (MAPP) or in the Mid-American Interconnected Network (MAIN). MAPP seasonal definitions of May through October for summer and November through April for winter have been used to define the seasons for this study.

Econometric models that tie monthly peaks to monthly energy requirements and to weather conditions on the days of peaks were explored but ultimately rejected since these factors did not adequately explain the observed history. This effort was also hindered by substantial gaps in the available daily weather data for weather stations near Escanaba. To obtain a complete series, one would need to use Green Bay data, which may not accurately reflect Escanaba conditions at time of peak.

The alternative forecast methodology used is based on seasonal load factors which in turn requires estimates of winter and summer total energy requirements. The energy forecasts have all been developed on EED's fiscal years, which end in June of each calendar year. Thus the energy forecasts need to be adjusted from a fiscal year to a MAPP year to synchronize the peak demand and energy forecasts. The MAPP year ending in 1995 consists of the winter period from November 1994 through April 1995 followed by the summer period from May 1995 through October 1995. The EED fiscal year ending in 1995 consists of July 1994 through June 1995. From 1994 through 2002, the ratio of EED energy requirements for the MAPP years was 101.1 percent of the equivalent fiscal year data. That factor has been used to convert all future fiscal year total energy requirements to a MAPP year basis. MAPP year total energy requirements were then split into summer and winter components based on the nine-year average split of 50.0 in each season. There was no clear trend to support a change in this allocation for the future.

The final step in developing the seasonal peak forecasts was to project the seasonal load factors. Our recent forecasts for numerous utilities in Minnesota, Wisconsin and the lower peninsula of Michigan have shown dramatically faster growth in summer peaks than in winter peaks. This reflects both the changing composition of class sales with increased concentration in the commercial and industrial classes and rapid increases in the saturation of central air conditioning in both commercial and residential buildings. EED's summer load factor has declined from 66.6 percent in 1994 to 53.3 percent in 2002.[4] The summer load factor has been projected to continue decreasing at a rate of 0.2 percent per year, which reduces the 2003 figure of 56.8 percent to 52.8 percent by 2023. The EED winter load factor has generally been higher than the summer equivalent but has also trended gradually downward. The decrease from 1994 to 2003 has been from 66.2 percent to 64.4 percent. The 2004 forecast is based on the historic four-year average of 66.1 percent and continuing decreases of 0.1 percent per year, which results in a 2023 winter load factor of 64.1 percent. Since much of the growth in sales is coming from a few large power customers, significant changes in their seasonal and peak usage patterns could result in modifications of these load factor projections.

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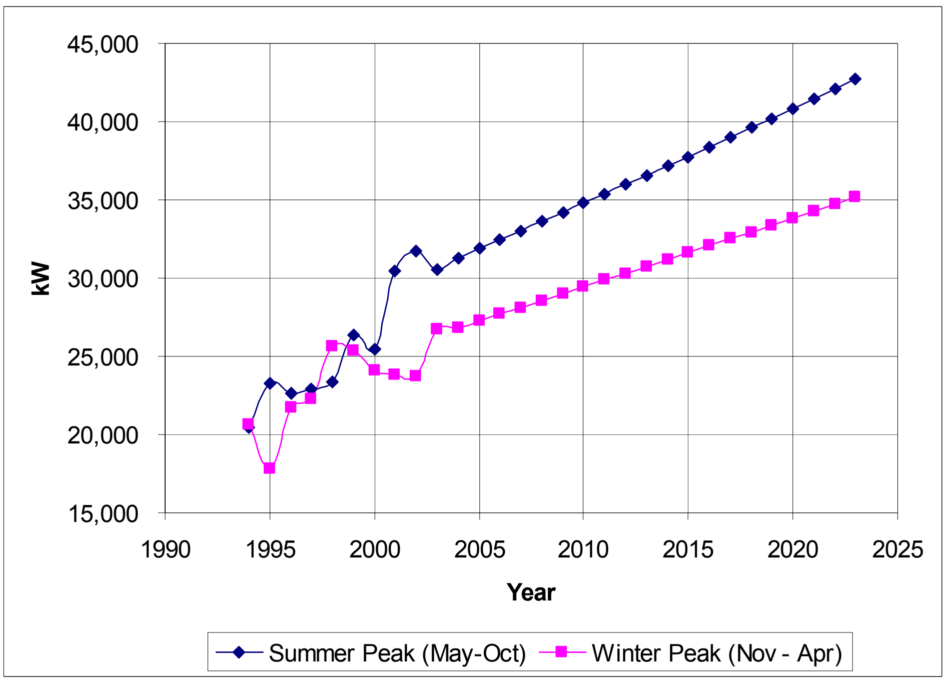
[4] Data for summer 2003 have not been used for this study to this point. That data should be considered as soon as it becomes available to allow calibration of the forecast to the most recent experience. The 2003 summer load factor has been estimated as 56.8 percent, which represents the four-year average figure.

Figure 6.3 and Table 6.2 present the seasonal peak demand forecasts. Prior to 2000, EED loads were closely balanced with the peak occurring in either winter or summer depending on the weather in a particular year. Since 2000, however, the summer peak has been dominant. Based on the historic trends in EED load factors and energy splits and the experience of numerous other regional utilities with similar weather conditions, it is anticipated that the summer peak will continue to dominate and that the gap between winter and summer demands will grow.

Figure 6.3 Seasonal Coincident Peak Demands



The summer peak, which is also the annual peak throughout the forecast period, is expected to increase from 31,725 kW in 2002 to 42,765 kW by 2023, which represents a growth rate of 1.4 percent per year.

Table 6.2 EED Seasonal Coincident Peak Demands

MAPP Year	Winter TER MWh	Winter LF %	Winter Peak kW	Summer TER MWh	Summer LF %	Summer Peak kW
1994	59,736	66.2%	20,616	59,795	66.6%	20,500
1995	59,886	76.9%	17,776	64,903	63.7%	23,259
1996	64,514	67.8%	21,731	64,379	64.9%	22,649
1997	68,550	70.1%	22,312	64,349	64.0%	22,944
1998	67,489	60.0%	25,668	66,788	65.3%	23,364
1999	69,120	62.1%	25,400	68,842	59.5%	26,400
2000	69,543	65.9%	24,100	67,591	60.5%	25,500
2001	73,689	70.7%	23,800	71,707	53.7%	30,500
2002	69,995	67.4%	23,700	74,079	53.3%	31,725
2003	75,226	64.4%	26,685	76,029	56.8%	30,582
2008	82,079	65.6%	28,567	82,102	55.8%	33,617
2013	87,639	65.1%	30,737	87,664	54.8%	36,550
2018	93,217	64.6%	32,946	93,243	53.8%	39,599
2023	98,797	64.1%	35,190	98,825	52.8%	42,765

6.4 Design Loads

In planning reliable power supply, it is essential to consider both load forecast uncertainty and the reserves necessary to cover forced outages of generating units. Based on the historic fits of the energy forecasting equations, it is reasonable to assume a broadening range of about plus or minus one percent per year for each year of the forecast period. Thus, summer energy requirements could be as high as 119 GWh in 2023. The summer load factor forecast could also be calibrated to the lowest recent historic figure rather than the four-year average, which would reduce the 2023 estimate to 49.3 percent. The combined impact of these sensitivity tests would be to increase the 2023 summer peak forecast to 54.9 MW compared to the base forecast of 42.8 MW. This analysis provides a reasonable estimate of the upper end of the probable forecast range.

For a utility with no reliable connections to an integrated grid, power supply plans were often developed to cover a first order contingency defined as a forced outage of the largest generating unit at the time of the system peak. This required utilities to carry numerous small units or very large reserves. As utilities became more interconnected through transmission networks, each could rely on capacity from other utilities within their reliability region to provide reserve capacity. In that context, loss-of-load probability studies were developed to establish reasonable planning reserve margins. Typical required reserves in the MAPP reliability region, for example, are between 15 and 20 percent of the peak demands.

To a certain extent, the selection of the appropriate planning reserve must reflect the philosophy of the utility regarding the relative costs of capacity and the risks of outages. PSE proposes to discuss this matter with EED to gain concurrence on the appropriate level of planning reserves to include in the power supply plan. Our initial inclination is to plan for the peak forecast plus 20 percent reserves, but this should be confirmed with EED.