Indiana Electricity Projections: The 2003 Forecast

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FOREWORD

This report presents the 2003 projections of future electricity requirements for the state of Indiana for the period 2002-2021. This study is part of an ongoing independent electricity forecasting effort conducted by the State Utility Forecasting Group (SUFG). SUFG was formed in 1985 when the Indiana legislature mandated a group be formed to develop and keep current a methodology for forecasting the probable future growth of electricity usage within Indiana. The Indiana Utility Regulatory Commission contracted with Purdue and Indiana Universities to accomplish this goal. SUFG produced its first set of projections in 1987 and has updated these projections periodically. This is the ninth set of projections.

The objective of SUFG, as defined in Indiana Code 8-1-8.5 (amended in 1985), is as follows:

To arrive at estimates of the probable future growth of the use of electricity...the commission shall establish a permanent forecasting group to be located at a state-supported college or university within Indiana. The commission shall financially support the group, which shall consist of a director and such staff as mutually agreed upon by the commission and the college or university, from funds appropriated by the commission. This group shall develop and keep current a methodology for forecasting the probable future growth of the use of electricity within Indiana and within this region of the nation. To do this the group shall solicit the input of residential, commercial and industrial consumers and the electric industry.

SUFG has maintained a similar format for this report as was used in recent reports to facilitate comparisons. Details on the operation of the modeling system are not included; for that level of detailed information, the reader is asked to contact SUFG directly or to look back to the 1999 forecast that is available for download from the SUFG website located at:

https://engineering.purdue.edu/IIES/SUFG

The authors would like to thank the Indiana utilities, consumer groups and industry experts who contributed their valuable time, information and comments to this forecast.

Finally, the authors would like to gratefully acknowledge the Indiana Utility Regulatory Commission for its input and suggestions.

This report was prepared by the State Utility Forecasting Group. The information contained in this forecast should not be construed as advocating or reflecting any other organization's views or policy position. Further details regarding the forecast and methodology may be obtained from SUFG at:

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CHAPTER 1
EXECUTIVE SUMMARY

Overview

In November 2001, the State Utility Forecasting Group (SUFG) released its eighth set of projections of future electricity requirements for the state of Indiana. That forecast was based on projections of economic activity that were produced in February 2001. Since then, the national economy has weakened considerably. This report, which is based on the August 2002 macroeconomic forecast from the Center for Econometric Modeling Research (CEMR) at Indiana University, reflects the current economic climate.

This forecast projects electricity usage to grow at a rate of 2.16 percent per year. This growth rate is similar to that seen in the late 1990s and includes a gradual economic recovery. Peak electricity demand is projected to grow at an average rate of 2.07 percent annually. This corresponds to about 420 megawatts (MW) of increased peak demand per year.

The 2003 forecast predicts Indiana electricity prices to remain steady in real (inflation adjusted) terms through the end of the decade and then slowly fall through the remainder of the forecast.

Previous SUFG forecasts have identified early resource needs that could be classified as peaking, which are intended to be operated only during periods of high electricity usage. Peaking resources are characterized by relatively low construction costs, but high operating costs. The recent addition of peaking generators to the statewide generation mix has reduced that need. While some additional peaking capacity will be needed in the future, this is the first SUFG forecast that identifies a substantial need for additional baseload capacity in the first few years. Baseload generators, which are intended to be used even during period of low demand, have relatively high constructions costs, but low operating costs. This forecast identifies a need for over 1,000 MW of additional baseload resources by 2008.

While SUFG identifies resource needs in its forecasts, it does not advocate any specific means of meeting them. Required resources could be met through conservation measures, purchases from merchant generators or other utilities, construction of new facilities or some combination thereof. The best method for meeting resource requirements may vary from one utility to another.

Other issues addressed in the forecast include:

- What is the impact of the economic slowdown on Indiana peak demand and electricity requirements?
- Can coal compete with natural gas as the fuel of choice for new electricity generators?
- How have recent wholesale electricity prices affected new generation plant construction?

Outline of the Report

The current forecast continues to respond to SUFG's legislative mandate to forecast electricity demand. It includes projections of electricity energy requirements, peak demand, prices, and capacity requirements. It also provides projections for each of the three major customer sectors: residential, commercial and industrial.

Chapter 2 of the full report briefly describes SUFG's forecasting methodology. A complete description of the SUFG regulated modeling system used to develop this forecast was included in the 1999 forecast and is available at the SUFG website:

https://engineering.purdue.edu/IIES/SUFG.

Chapter 3 through 7 describe the data inputs and integrated projections of electricity demand, supply and price for each major consumption sector in the state under three scenarios:

- the *base scenario*, which is intended to represent the most likely electricity forecast, i.e., the forecast has an equal probability of being low or high;

- the *low scenario*, which is intended to represent a plausible lower bound on the electricity sales forecast and thus, has a low probability of occurrence; and
- the *high scenario*, which is intended to represent a plausible upper bound on the electricity sales forecast and thus, has a low probability of occurrence.

Chapter 8 discusses the three issues of importance to Indiana electricity policymakers described on page 1-1.

Finally, Appendix A depicts the data sources used to produce the forecast and provides historical data for energy, peak demand and prices.

The Regulated Modeling System

The SUFG modeling system explicitly links electricity costs, prices and sales on a utility-by-utility basis under each scenario. Econometric and end-use models are used to project electricity use for each major customer group — residential, commercial and industrial -- using fuel prices and economic drivers to simulate growth in electric energy use. The projections for each utility are developed from a consistent set of statewide economic, demographic and fossil fuel price projections. In order to project electricity costs and prices, generation resource plans are developed for each utility and the operation of the generation system is simulated. These resource plans reflect "need" from both a statewide and utility perspective.

Resource needs are determined on a statewide basis by matching existing statewide resources to projected diversified statewide peak demand plus reserves. For planning purposes, SUFG assumed a 15 percent reserve margin[1] for the state. Due to diversity in demand among the utilities, a statewide 15 percent reserve margin occurs when individual utility reserve margins are roughly 11 percent. When the state reserve margin falls below 15 percent, resource additions are chosen from a list of resource options based on an analysis of load versus existing capacity for individual utilities.

The dynamic interactions between customer purchases, a utility's operating and investment decisions and customer rates are captured by cycling through the various submodels until an equilibrium, or balance, among demand, supply and price is attained.

Major Forecast Assumptions

In updating the modeling system to produce the current forecast, new projections were developed for all major exogenous variables.[2] These assumptions are summarized below.

Economic Activity Projections. One of the largest influences in any energy projection is growth in economic activity. Each of the sectoral energy forecasting models is driven by economic activity projections, i.e., personal income, population, commercial employment and industrial output. The economic activity assumptions for all three scenarios were derived from the Indiana macroeconomic model developed by CEMR. SUFG used CEMR's August 2002 projections for its base scenario. A major input to CEMR's Indiana model

[1] SUFG reports reserves in terms of reserve margins instead of capacity margins. Care must be taken when using the two terms since they are not equivalent. A 15 percent reserve margin is equivalent to a 13 percent capacity margin.

$$\text{Capacity Margin} = [(\text{Capacity-Demand}) / \text{Capacity}]$$

$$\text{Reserve Margin}=[(\text{Capacity-Demand}) / \text{Demand}]$$

[2] Exogeneous variables are those variables that are determined outside the modeling system and are then used as inputs to the system.

is a projection of total U.S. employment, which is derived from CEMR's model of the U.S. economy. The CEMR Indiana projections are based on a national employment projection of 0.98 percent growth per year over the forecast period. Indiana total employment is projected to grow at an average annual rate of 1.24 percent. Other key economic projections are:

- Real personal income (the residential sector model driver) is expected to grow at a 2.36 percent annual rate.
- Non-manufacturing employment (the commercial sector model driver) is expected to average 1.79 percent annual growth rate over the forecast horizon.
- Despite the continued decline of manufacturing employment, manufacturing Gross State Product (GSP) (the industrial sector model driver) is expected to rise at a 1.50 percent annual rate as gains in productivity offset declines in employment.

To capture some of the uncertainty in energy forecasting, SUFG also requested CEMR to produce low and high growth alternatives to its base economic projection. In effect, the alternatives describe a situation in which Indiana either loses or gains shares of national industries compared to the base projection.

Demographic Projections. Population growth for all scenarios is 0.25 percent per year. This projection is from the Indiana Business Research Center (IBRC) at Indiana University.

The SUFG forecasting system includes a housing model that utilizes population and income assumptions to project the number of households. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of 0.66 percent over the forecast period.

Fossil Fuel Price Projections. SUFG's current assumptions are based on the January 2003 projections produced by the Energy Information Administration (EIA) for the East North Central Region. SUFG's fossil fuel real price[3] projections are as follows:

- *Natural Gas Prices*: Gas price projections for all customers decrease slightly through 2006 and increase moderately over the remainder of the forecast horizon.
- *Utility Price of Coal*: Coal prices will decline slightly in real terms throughout the entire forecast horizon.

The Base Scenario

Figure 1-1 shows the current base scenario projection for electricity requirements in gigawatthours (GWh), along with the projections from the previous two forecast reports. Similarly, the base projection for peak demand is shown in Figure 1-2. The annual growth rates for electricity requirements and peak demand in this forecast are 2.16 and 2.07 percent, respectively, compared to 1.87 and 1.95 percent in the previous forecast.

In this instance, a comparison of growth rates for electricity requirements between the current and previous forecast can be misleading. Despite the higher growth rate, the trajectory for electricity requirements in this forecast actually lies below the one for the 2001 forecast. This is caused by the relative lack of growth in actual sales between 1999 and 2001. Therefore, as the two trajectories converge near the end of the forecast, the current forecast exhibits a higher growth rate. The industrial electricity sales projections in the two forecasts exhibit the same phenomenon (see Table 1-1). The electricity sales projections for the residential sector and commercial sector are closer to the 2001 projections.

[3] Real prices are calculated to reflect the change in the price of a commodity after taking out the change in the general price levels (i.e., the inflation in the economy).

Figure 1-1. Indiana Electricity Requirements in GWh (Historical, Current and Previous SUFG Base Forecasts)

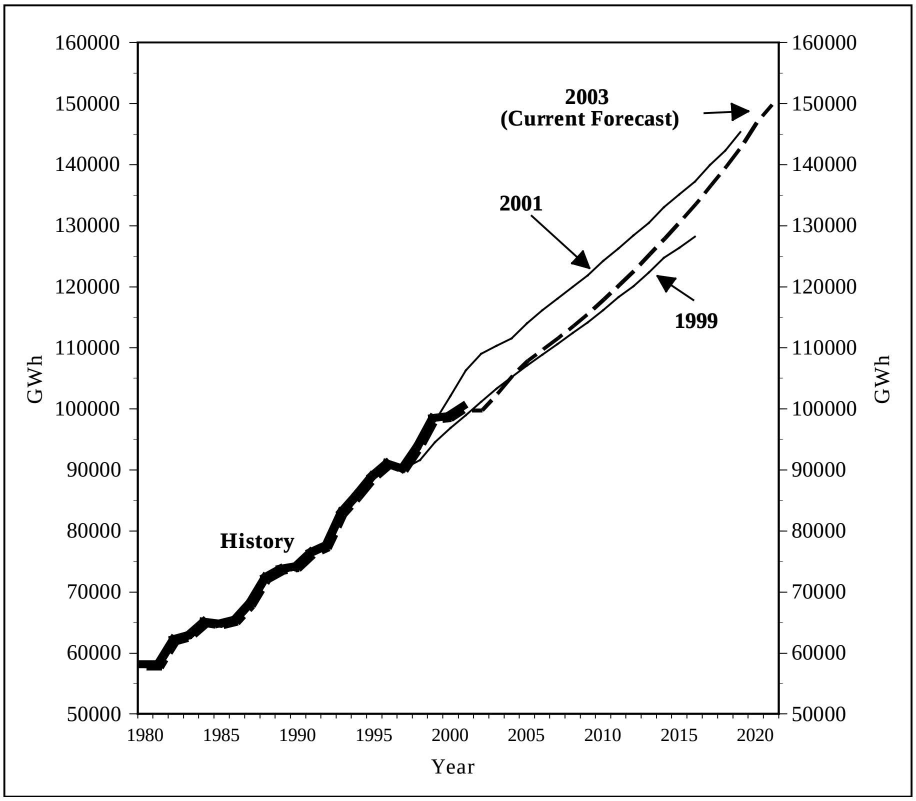


Table 1-1. Annual Electricity Sales Growth (%) By Sector (Current vs. 2001 Projections)

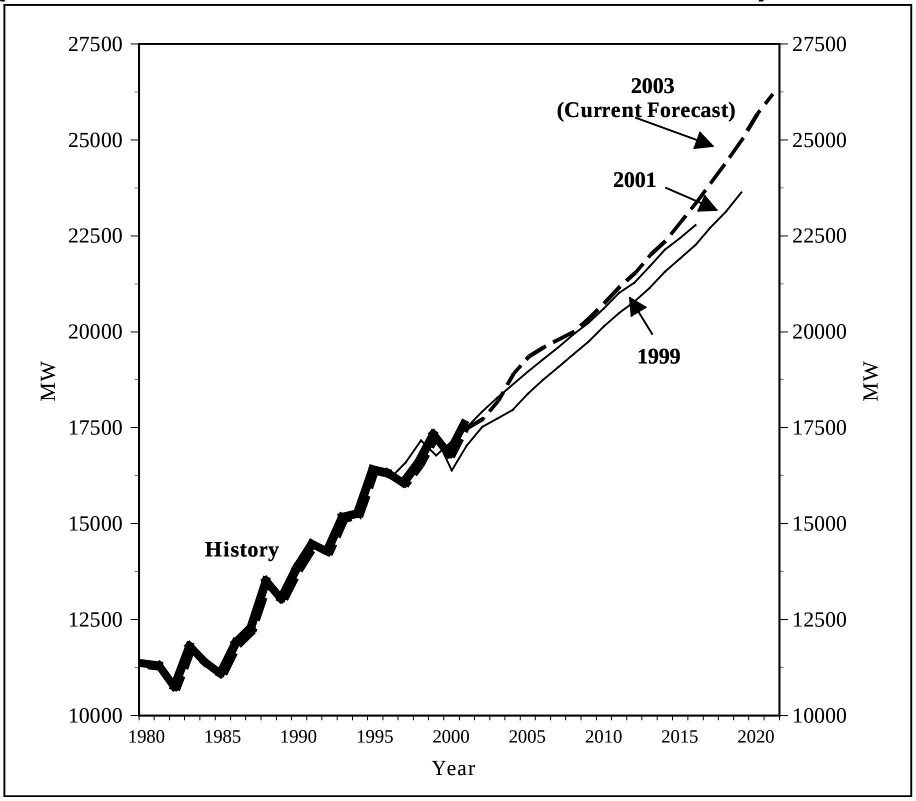
	Electricity Sales Growth	
Sector	Current (2002-2021)	2001 (2000-2019)
Residential	1.95	2.02
Commercial	2.71	2.57
Industrial	1.97	1.32
Total	**2.16**	**1.87**

The growth in peak demand is similar to that projected in 2001. The projections of peak demand are for normal weather patterns, and projected peak demand for long-run planning is reduced by interruptible loads.

Another measure of peak demand growth can be obtained by considering the year to year MW load change. In Figure 1-2, the annual increase is about 420 MW.

This forecast report marks a slight change in the way that growth rates are presented. In past reports, growth rates were calculated from the last year of actual data that was available to the last year of the forecast. This possibly could lead to misleading results if the last year of actual data was very different from normal. One example of this might be if the last actual year had an unusually hot summer, resulting in exceptionally high peak demand. By going from the actual observation to a projected value, which assumes normal weather, the growth rate would be skewed too low. Therefore, SUFG calculates growth rates for

Figure 1-2. Indiana Peak Demand Requirements in MW (Historical, Current and Previous SUFG Base Forecasts)



projections from the first forecast year to the last. As in previous forecasts, the period of time over which the growth rate is calculated is provided.

Resource Implications

SUFG's resource plans include both demand-side and supply-side resources to meet forecast demand. Demand-side management (DSM) impacts and interruptible loads are netted from the demand projection and supply-side resources are added as necessary to maintain a 15 percent reserve margin. Although this approach provides a reasonable basis for estimating future electricity prices for planning purposes, it does not ensure that the resource plans are least cost.

Demand-Side Resources

The current projection includes the energy and demand impacts of existing or planned utility-sponsored DSM programs. Incremental DSM programs, which include new programs and the expansion of existing programs, are projected to reduce peak demand by approximately 28 MW.

These DSM projections do not include the reductions in peak demand due to interruptible load contracts with large customers. Approximately 840 MW of large load is classified as interruptible in this forecast, about 200 MW less than in the 2001 forecast.

Supply-Side Resources

SUFG's base resource plan includes all currently planned capacity changes. Planned capacity changes include: certified, rate base eligible generation additions, retirements, deratings due to NOx control retrofits and net changes in firm out-of-state purchases and sales. SUFG does not attempt to forecast long-term out-of-state contracts other than those currently in place. Generic firm wholesale purchases are then added as necessary during the forecast period to maintain a statewide 15 percent reserve margin. The 15 percent reserve margin is a "rule-of-thumb" that reflects recent national average reserve margins. Due to diversity in demand between utilities, a statewide 15 percent reserve margin occurs when individual utility reserve margins are roughly 11 percent.

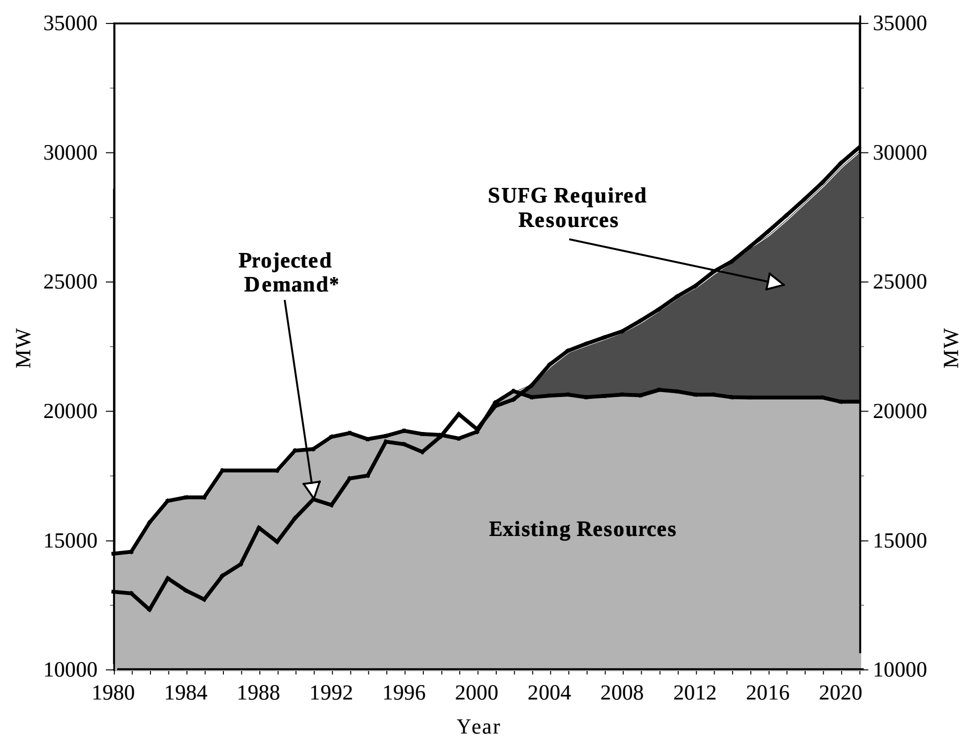
Resource Needs

Figure 1-3 and Table 1-2 show the statewide resource plan for the SUFG base scenario. Over the first half of the forecast period, about 3,700 MW of additional resources are required. The net change in generation includes the retirement of units as reported in the utilities' 2001 Integrated Resource Plan (IRP) filings. Over the second half of the forecast period, an additional 6,000 MW of resources are required to maintain target reserves.

Equilibrium Price and Energy Impact

SUFG's base scenario equilibrium real electricity price trajectory is shown in cents per kilowatthour (kWh) in Figure 1-4. Real prices are projected to remain steady for the first half of the forecast period and then slowly fall through the remainder of the forecast.

Figure 1-3. Indiana Total Demand and Supply in MW (SUFG Base)



*Projected Demand includes 15% Reserve Margin

Table 1-2. Indiana Resource Plan (SUFG Base)

Year	Uncontrolled Peak Demand [1]	Interruptible Loads	Net Peak Demand [2]	Existing/ Approved Capacity [3]	Incremental Change in Capacity [4]	Projected Additional Capacity Requirements [5]				Total Capacity [6]	Reserve Margin
						Peaking	Cycling	Baseload	Total		
2001			17531	20294		0	0	0	0	20294	16
2002	18451	689	17762	20749	455	0	0	0	0	20749	17
2003	18945	714	18231	20506	-243	250	240	60	550	21056	15
2004	19698	764	18934	20572	66	280	670	240	1190	21762	15
2005	20177	779	19398	20613	41	410	840	440	1690	22303	15
2006	20416	784	19633	20513	-100	500	890	660	2050	22563	15
2007	20644	799	19845	20565	52	600	840	810	2250	22815	15
2008	20856	809	20047	20615	50	650	740	1060	2450	23065	15
2009	21229	829	20400	20587	-28	750	810	1300	2860	23447	15
2010	21638	844	20794	20792	205	710	840	1580	3130	23922	15
2011	22068	844	21224	20732	-60	820	990	1880	3690	24422	15
2012	22425	844	21581	20607	-125	920	1130	2160	4210	24817	15
2013	22888	844	22044	20607	0	1030	1220	2480	4730	25337	15
2014	23254	844	22410	20507	-100	1160	1330	2800	5290	25797	15
2015	23744	844	22900	20504	-3	1270	1420	3160	5850	26354	15
2016	24257	844	23413	20504	0	1310	1480	3540	6330	26834	15
2017	24789	844	23945	20504	0	1400	1540	3980	6920	27424	15
2018	25333	844	24489	20504	0	1520	1640	4410	7570	28074	15
2019	25901	844	25057	20504	0	1630	1730	4870	8230	28734	15
2020	26553	844	25709	20341	-163	1900	1760	5460	9120	29461	15
2021	27075	844	26231	20341	0	2020	1840	5870	9730	30071	15

Notes:

1. Uncontrolled peak demand is the peak demand without any interruptible loads being called upon.
2. Net peak demand is the peak demand after the interruptible loads are taken into account.
3. Existing/approved capacity includes installed capacity plus approved new capacity plus firm purchases minus firm sales.
4. Incremental change in capacity is the change in existing/approved capacity from the previous year. The change is due to new, approved capacity becoming operational, retirements of existing capacity, and changes in firm purchases and sales.
5. Projected aditional capacity requirements is the cumulative amount of additional capacity needed to meet future requirements.
6. Total capacity requirements is the total statewide capacity required including existing/approved capacity and projected additional capacity requirements.

Since the change in prices over the forecast horizon is relatively small, price has little impact on the electricity requirements projection for this forecast.

SUFG's equilibrium price projections for two previous forecasts are also shown in Figure 1-4. The price projection labeled "2001" is the base from SUFG's 2001 forecast and the price projections labeled "1999" is the base case projection contained in SUFG's 1999 forecast. For the prior price forecasts, SUFG rescaled the original price projections to 2001 dollars (from 1996 dollars for the 1999 projection, and from 1999 dollars for the 2001 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

One major factor produces the differences among the price projections in Figure 1-4; namely, the capital cost assumptions for new generation equipment. Other factors such as energy and demand growth as well as fossil fuel price assumptions, especially coal, also influence the trajectory of future prices.

Low and High Scenarios

SUFG has constructed alternative, low and high growth scenarios. These low probability scenarios are used to indicate the forecast range, or dispersion of possible future trajectories. Figure 1-5 provides the statewide electricity requirements for the base, low and high scenarios. As shown in the figure, the annual growth rates for the low and high scenarios are about 0.90 percent lower and higher than the base scenario respectively. These differences are due to economic

Figure 1-4. Indiana Real Price Projections (2001 Dollars) (Historical, Current and Previous Forecasts)

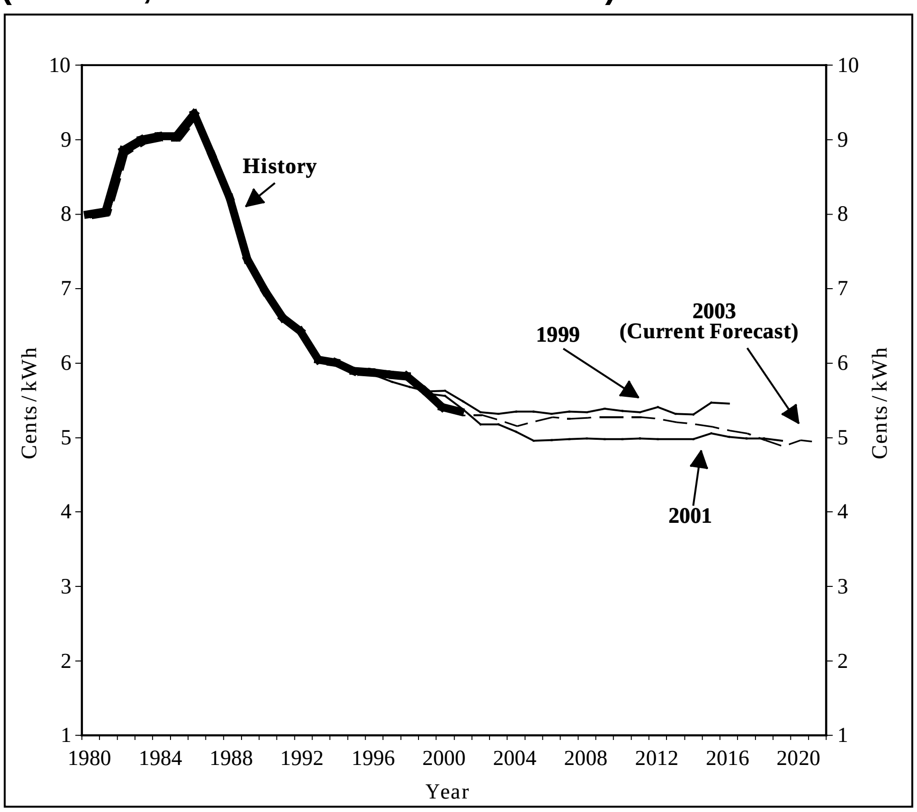
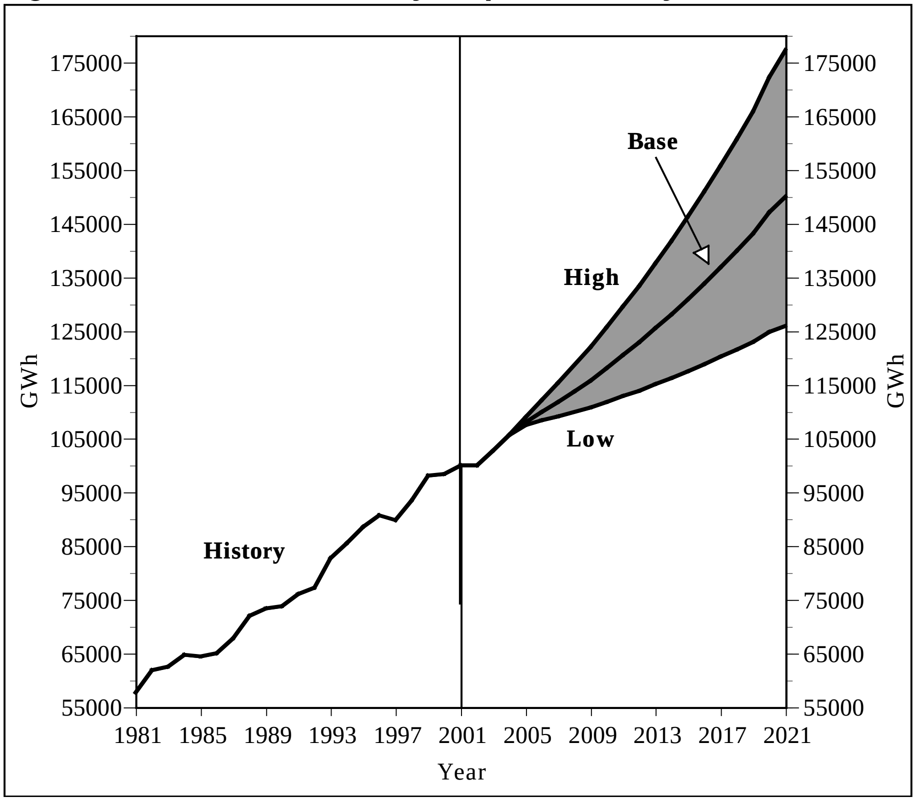


Figure 1-5. Indiana Electricity Requirements by Scenario in GWh



growth assumptions in the scenario-based projections. The trajectories for peak demand in the low and high scenarios are similar to the electricity requirements trajectories.

Issues of Interest to Policymarkers

Three issues of interest to policymakers are briefly addressed here. See Chapter 8 for more detailed discussions of these issues.

The Slowing Economy

Recent observations indicate that the current economic slowdown has had a greater effect on electricity requirements than on peak demand. This phenomenon occurs because the state's economy tends to be driven largely by the industrial sector, which is the single largest component of Indiana's electricity consumption. On the other hand, peak demand is driven largely by the residential sector, which has been much less affected by the economy. This issue is important since the need for new capacity is a function of peak demand.

Competition between Coal and Natural Gas

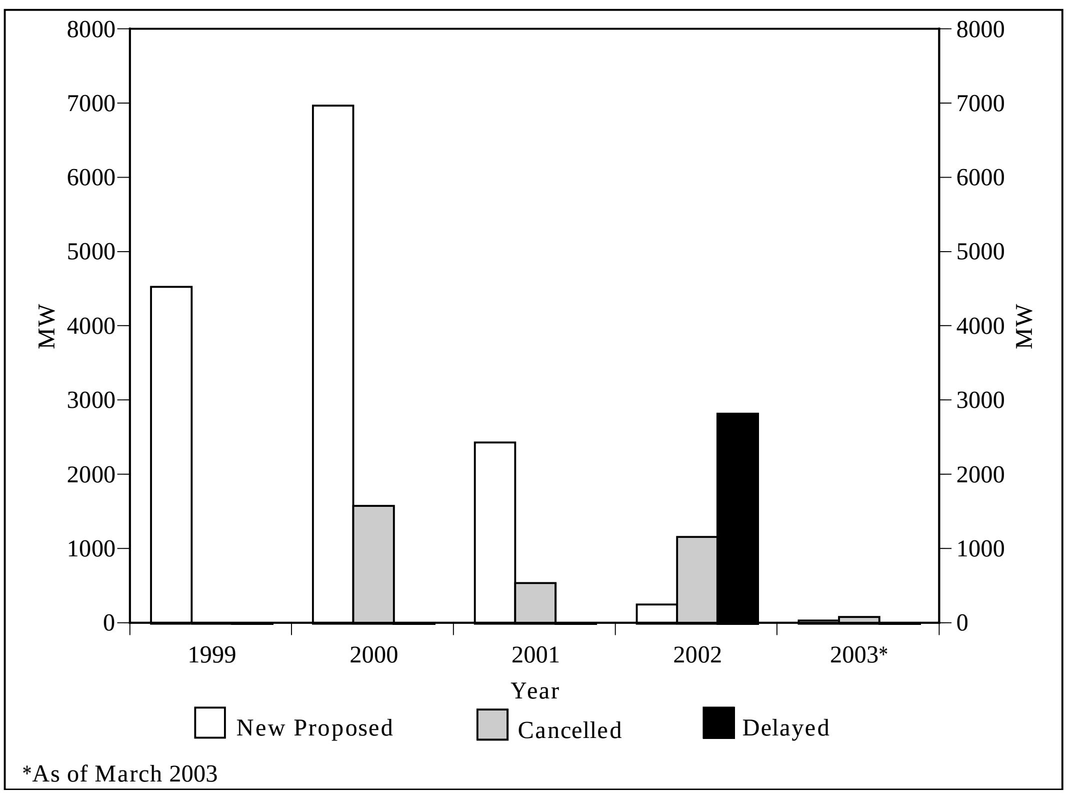
As Indiana enters a period when new base load capacity will be needed, the question of whether to use coal or natural gas for that capacity is a natural one. The decision to build coal-fired or natural gas-fired capacity is driven by three factors: the purchase and installation costs of the unit, the cost to operate the unit after it is built and the expected number of hours of operation during each year. Assuming the price of coal is 1 $/million British thermal unit (mmBtu) and the price of natural gas is 4 $/mmBtu, which are close to the present prices, a coal-fired unit would have to operate about 70 percent of the time or more to be economically competitive with a natural gas-fired unit. If the natural gas prices fell below 3.2 $/mmBtu, the coal-fired unit could not compete even if operated all the time. If natural gas prices rose to 5 $/mmBtu, the coal-fired unit can compete if operated more then half the time.

Recent Trends in New Generation Construction

The wholesale price spikes that occurred in the Midwest in 1998 and 1999 spurred a rush in new generation plans as companies attempted to cash in on the high prices. A combination of increased capacity and milder summer weather has prevented the price spikes from recurring in the past three years. This has resulted in a slowing of new plant announcements and some delays and cancellations of previously announced plants. Figure 1-6 shows how the large amount of new proposed capacity in 1999 and 2000 has tailed off in the years thereafter. The figure also shows the recent increase in cancellations and delays.

The values in Figure 1-6 are derived from a database of new plants that SUFG developed in 1998. The database is updated periodically based on information in trade press articles and correspondence with plant developers and state regulators.

Figure 1-6. Incremental Changes in Proposed Capacity in Indiana by Year



OVERVIEW OF SUFG ELECTRICITY MODELING SYSTEMS

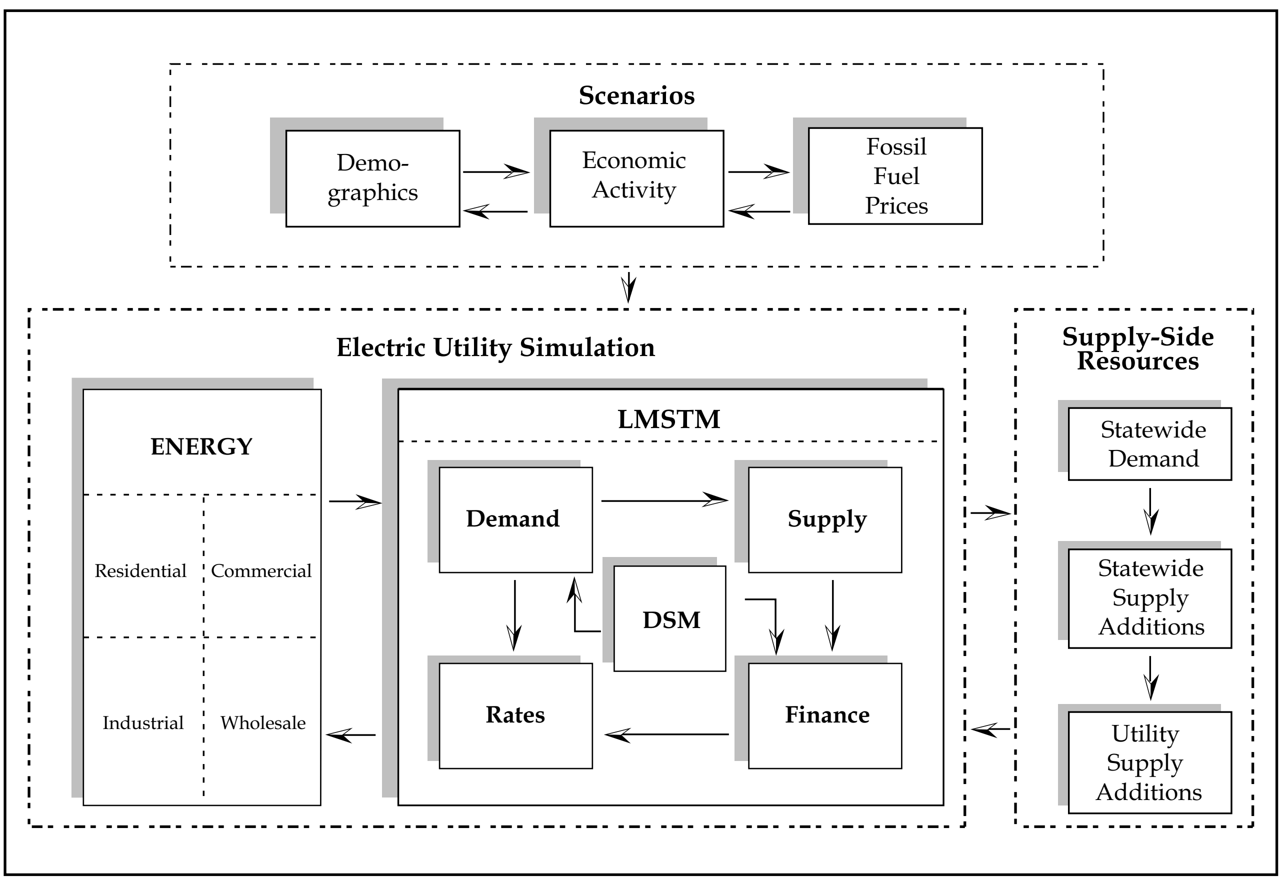
Regulated Modeling System

SUFG's integrated electricity modeling system projects electricity demand, supply and price for each electric utility in the state assuming continued regulation. The modeling system captures the dynamic interactions between customer demand, the utility's operating and investment decisions, and customer rates by cycling through the various submodels until an equilibrium is attained. The SUFG modeling system is unique among utility forecasting and planning models because of its comprehensive and integrated characteristics. The basic system components (submodels) and their principal linkages are illustrated in Figure 2-1 and then briefly described.

Energy Submodel

SUFG has developed and acquired both econometric and end-use models to project energy use for each major customer group. These models use fuel prices and economic drivers to simulate growth in energy use. The end-use models provide detailed projections of end-use saturations, building shell choices and equipment choices (fuel type, efficiency and rate of utilization). The econometric models capture the same effects but in a more aggregate way. These models use statistical relationships estimated from historical data on fuel prices and economic activity variables.

Figure 2-1. SUFG's Regulated Modeling System



Load Management Strategy Testing Submodel

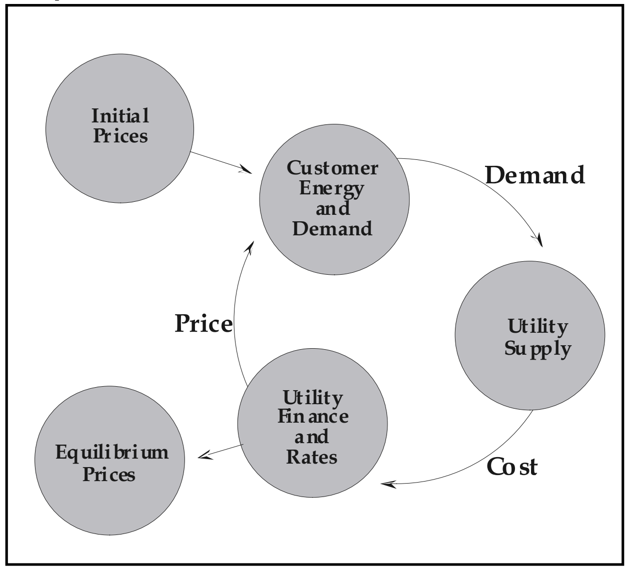
Developed by Electric Power Software, the Load Management Strategy Testing Model (LMSTM) is an electric utility system simulation model that integrates four submodels: demand, supply, finance and rates. Combined in this way, LMSTM simulates the interaction of customer demand, system generation, total revenue requirements and customer rates. LMSTM also preserves chronological load shape information throughout the simulation to capture time dependencies between customer demand (including DSM), and system operations and customer rates.

LMSTM is used to model the five investor-owned utilities (IOUs): Indiana Michigan Power Company (I&M), Indianapolis Power & Light Company (IPL), Northern Indiana Public Service Company (NIPSCO), PSI Energy, Inc. (PSI Energy) and Southern Indiana Gas & Electric Company (SIGECO). In addition, LMSTM is used for the three not-for-profit (NFP) utilities: Hoosier Energy Rural Electric Cooperative, Inc. (HEREC), Indiana Municipal Power Agency (IMPA) and Wabash Valley Power Association (WVPA).

Price Iteration

The energy modeling system cycles through five integrated submodels: energy, demand, supply, finance and rates. During each cycle, price changes in the model cause customers to adjust their consumption of electricity, which in turn affects system demand, which in turn affects the utility's operating and investment decisions. These changes in demand and supply bring forth yet another change in price and the cycle is complete. After each cycle, the modeling system compares the "after" electricity prices from the rates submodel to the "before" prices input to the energy consumption models. If these prices match, they are termed equilibrium prices in the sense that they balance demand and supply, and the iteration ends. Otherwise, the modeling system continues to cycle through the submodels until an equilibrium is attained as is illustrated in Figure 2-2.

Figure 2-2. Cost-Price-Demand Feedback Loop



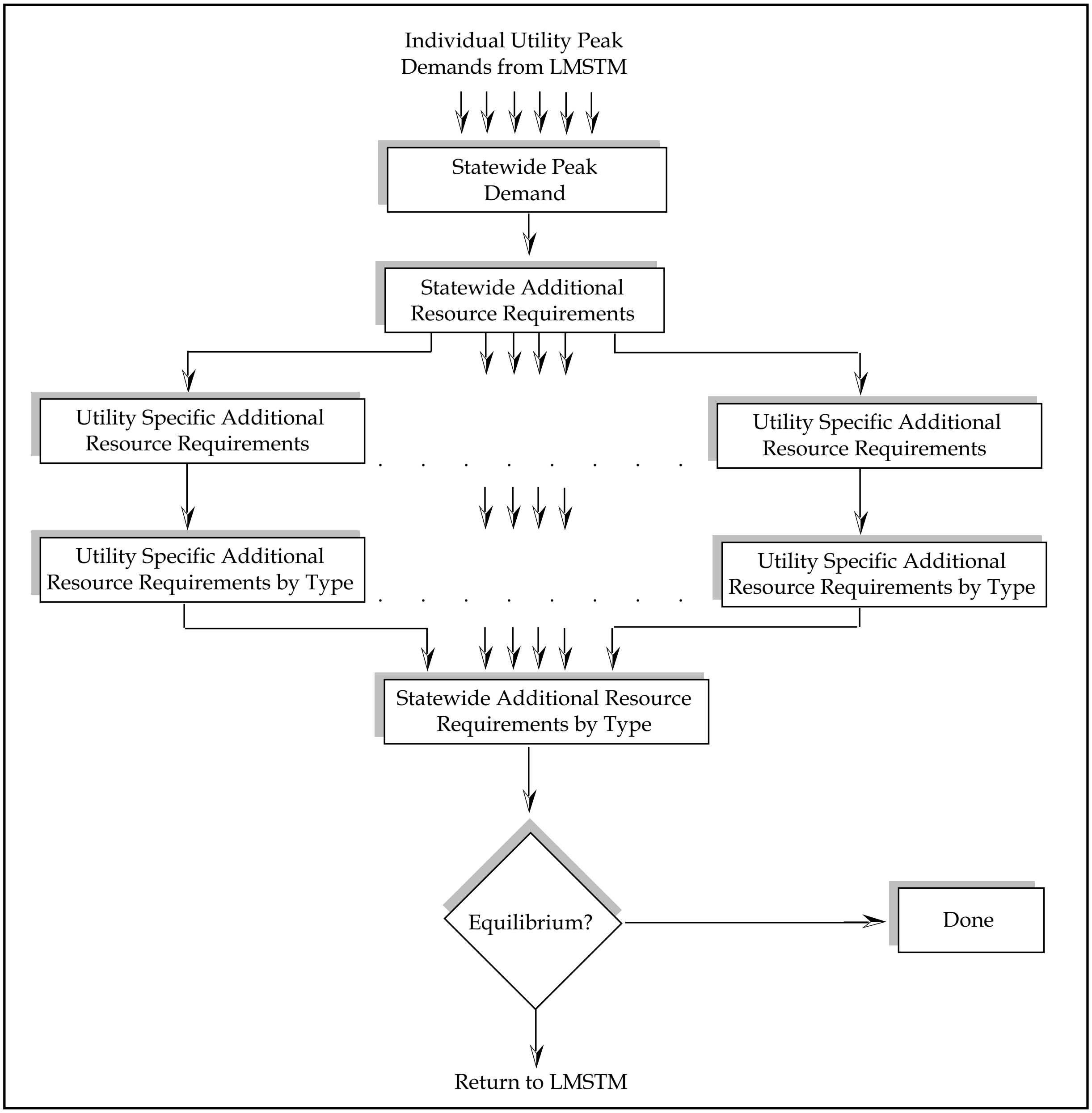
Supply-Side Resources

SUFG determines required resources according to a target statewide 15 percent reserve margin, but allocates those resources to three types (peaking, cycling and baseload) according to individual utility needs. This process is illustrated in the flowchart shown in Figure 2-3.

Individual utility peak demands developed from LMSTM are aggregated while accounting for load diversity and interruptible loads to determine the statewide peak demand for each year of the forecast. Load diversity occurs because the peak demands for all utilities do not occur at the same time. The additional resources required are determined for each year by comparing the peak demand with a 15 percent reserve margin to the existing capacity. The existing capacity has been adjusted for retirements, utility purchases and sales, and new construction that has been approved by the Indiana Utility Regulatory Commission (IURC).

The required resources are then assigned to the individual utilities with the lowest reserve margins, so that all utilities have similar reserve margins. These utility specific additional resource requirements are then assigned to one of the three types. This is accom-

Figure 2-3. Resource Requirements Flowchart



plished by comparing the utility's demand, which is divided into the three types using actual historical annual loadshapes, to the utility's existing generation resources, which are also assigned to the three types.

The statewide resource requirements by type are determined by summing the individual utility requirements. The overall process is done iteratively until an equilibrium is reached where resource requirements do not change from one iteration to the next.

Uncertainty

As stated above, SUFG's electricity projections are conditional on assumptions, such as economic growth, construction costs and fossil fuel prices. These assumptions are a principal source of uncertainty in any energy forecast. Another major source of uncertainty is the statistical error inherent in the structure of any forecasting model. To provide an indication of the importance of these sources of uncertainty, scenario-based projections are developed by operating the modeling system under varying sets of assumptions. These low probability, low and high scenarios capture much of the uncertainty associated with economic growth, fossil fuel prices and statistical error in the model structure.

Chronology

This is the ninth forecast SUFG has prepared. Previous forecasts were published in 1987, 1988, 1990, 1993, 1995, 1996, 1999 and 2001. In addition to these statewide forecasts, SUFG prepared forecasts of Indiana utility service area growth for the IURC's use in four Certificate of Need cases. Tables 2-1 through 2-4 present the chronology of enhancements and extensions of the SUFG electricity modeling system. Table 2-5 provides a list of software acronyms, along with a brief description of each.

Presentation and Interpretation of Forecast Results

There are several methods for presenting the various projections associated with the forecast. The actual projected value for each individual year can be provided or a graph of the trajectory of those values over time can be used. Additionally, average compound growth rates can be provided. There are advantages and disadvantages associated with each method. For instance, while the actual values provide a great deal of detail, it can be difficult to visualize how rapidly the values change over time. While growth rates provide a simple measure of how much things change from the beginning of the period to the end, they mask anything that occurs in the middle. For these reasons, SUFG generally uses all three methods for presenting the major forecast projections.

This forecast report marks a slight change in the way that growth rates are presented. In past reports, growth rates were calculated from the last year of actual data that was available to the last year of the forecast. This possibly could lead to misleading results if the last year of actual data was very different from normal. One example of this might be if the last actual year had an unusually hot summer, resulting in exceptionally high peak demand. By going from the actual observation to a projected value, which assumes normal weather, the growth rate would be skewed too low. Therefore, SUFG calculates growth rates for projections from the first forecast year to the last. As in previous forecasts, the period of time over which the growth rate is calculated is provided.

Table 2-1. Chronology of Regulated Modeling Enhancements

1985	•SUFG Established
1987	•Econometric Models --SUFG Residential (Five IOUs) --SUFG Commercial (Statewide) --Cornel Industrial (Statewide End-Use Models) --Commercial Energy Demand Modeling System (CEDMS: Statewide) --Residential Electric End-Use Energy Modeling System (REEMS: Statewide) •Peak Load --Load Factor
1988	•Load Shape - Hourly Electric Load Model (HELM) •Forecasting Capability for NFPs Added •Industrial End-Use Planning Methodology (INDEPTH) Industrial Econometric Model
1991	•Movement to More Utility-Specific Modeling Begun •Load Shape - Load Management Strategy Testing Model (LMSTM) Demand Submodel
1993	•Utility-Specific Modeling --INDEPTH (IOUs) --CEDMS (IOUs) --Housing (All) •Updated Residential and Commercial Econometric Elasticity Models for NFPs
1994	•Iron & Steel Industry Modeled
1995	•Iron & Steel Industry Model Updated •Aluminum Industry Modeled •Foundries Industry Modeled •Transportation Industry Modeled •Motor Model Developed
1996	•Residential Econometric Models Updated •Commercial End-Use Model Recalibrated
2000	•NOx Control Retrofits Modeled
2001	•Wholesale Market Generic Purchases Modeled

Table 2-2. Chronology of Supply, Finance and Rates Enhancements

1987	• Total Electric Planning Model (TELPLAN: IOUs)
1991	• Load Management Strategy Testing Model (LMSTM: IOUs)
1993	• LMSTM (NFPs)
1994	• Integrated Resource Planning (IRP) Manager
1998	• SEPRIL Report, "Plant Design, Performance, and Cost Comparison Study"
2001	• Inclusion of Wholesale Market Generic Purchases

Table 2-3. Chronology of Demand-Side Management Enhancements

1990	• Conservation Potential and Acid Rain Studies
1991	• DSIMPACT • Modeled IOU DSM
1993	• Explicit Modeling of Utility DSM Programs DSManager
1994	• Technology-Based End-Use Energy Modeling System (TEEMS)

Table 2-4. Chronology of Model Applications

1987	• SUFG 1987 Forecast
1988	• SUFG 1988 Forecast • SUFG Acid Rain Studies
1989	• Indiana State Agency Workgroup Acid Rain Studies
1990	• SUFG 1990 Forecast • ISAW Acid Rain Studies
1991	• PSI Energy Certificate of Need Combustion Turbine (CT)
1992	• IPL Certificate of Need (CT) • PSI Energy Certificate of Need (Destec)
1993	• SUFG 1993 Forecast
1994	• SUFG 1994 Forecast • Quarterly Update (4) of 1993
1996	• SUFG 1996 Forecast
1998	• SUFG Interim Report on Competitive Restructuring
1999	• SUFG 1999 Forecast
2000	• NOx Impact Study
2001	• SUFG 2001 Forecast
2002	• SUFG 2002 Forecast Update • PSI Certificate of Need (CTs)
2003	• SUFG 2003 Forecast

Table 2-5. Acronyms and Definitions

CEDMS	-	Commercial Energy Demand Modeling System. Off-shoot of TVA end-use model, supported and enhanced by Jerry Jackson and Associates
CPLEX	-	A mathematical optimizer for linear and integer programming problems
DSIMPACT	-	A detailed DSM evaluation model developed for SUFG by Ed Frye to link SUFG's energy models to DSM program evaluation
DSManager	-	Demand-Side Manager. An EPRI sponsored DSM screening model supported by Electric Power Software
GAMS		General Algebraic Modeling System. This computer platform has higher order computer programming languages that are designed to interface with other mathematical solvers, such as CPLEX
HELM	-	Hourly Electric Load Model. Builds up end use (or more aggregate) load using 8760 hourly loads per year. Developed with EPRI sponsorship
INDEPTH	-	Methodology for forecasting and shaping industrial electricity use at the service area level.
IRP-Manager	-	Integrated Resource Planning Manager. A detailed planning model which simultaneously evaluates DSM programs and supply-side resources under uncertainty. Developed and support by Electric Power Software
ISAW		Indiana State Agency Workgroup. An interagency workgroup which analyzed compliance strategies for several clean air proposals
LMSTM	-	Load Management Strategy Testing Model. A detailed dispatch, finance, rates and environmental analysis model with explicit treatment of DSM. Supported by Electric Power Software
REEMs	-	Residential Electric End-Use Energy Modeling System. Off-shoot of TVA end-use model, originally supported by Dennis O'Neal of Texas A&M
TEEMs	-	Technology-Based End-Use Energy Modeling System jointly developed by SUFG and EPS. TEEMS integrates the functions of end-use forecasting and DSM resource forecasting into a single modeling framework with a common database
TELPLAN	-	Total Electric Planning Model. This model includes dispatch, finance and environmental analysis capabilities. EPRI sponsored in early 1980s

INDIANA PROJECTIONS OF ELECTRICITY REQUIREMENTS, PEAK DEMAND, RESOURCE NEEDS AND PRICES

Introduction

This chapter presents the forecast of future electricity requirements and peak demand. It also includes the associated new resource requirements and price implications. This report includes three scenarios of future electricity demand and supply: base, low and high. The base scenario is developed from a set of exogenous assumptions that is considered "most likely," i.e., each assumption has an equal probability of being lower or higher. Additionally, SUFG developed low and high growth scenarios based on plausible sets of exogenous assumptions that have a lower probability of occurrence. These scenarios are designed to indicate a plausible forecast range, or degree of uncertainty underlying the base projection. The most probable projection is presented first.

Most Probable Forecast

As shown in Figures 3-1 and 3-2, SUFG's current base scenario projection indicates annual growth of electricity requirements and peak demand of 2.16 and 2.07 percent, respectively. The shaded numbers in the tables and the heavy line in the graphs indicate historical values.

As shown in Table 3-1, the growth rate for electricity sales in this forecast is higher than in the 2001 forecast. The higher growth rate is caused primarily by a higher growth rate in the industrial sector, with small changes in the growth rates for electricity sales in the residential and commercial sectors.

Table 3-1. Annual Electricity Sales Growth (%) By Sector (Current vs. 2001 Projections)

	Electricity Sales Growth	
Sector	Current (2002-2021)	2001 (2000-2019)
Residential	1.95	2.02
Commercial	2.71	2.57
Industrial	1.97	1.32
Total	**2.16**	**1.87**

In this instance, a comparison of growth rates for electricity requirements between the current and previous forecast can be misleading. Despite the higher growth rate, the trajectory for electricity requirements in this forecast actually lies below the one for the 2001 forecast. This is caused by the relative lack of growth in actual sales between 1999 and 2001. Therefore, as the two trajectories converge near the end of the forecast, the current forecast exhibits a higher growth rate. The industrial electricity sales projections in the two forecasts exhibit the same phenomenon (see Table 1-1). The electricity sales projections for the residential sector and commercial sector are closer to the 2001 projections.

The growth in peak demand is slightly higher than that projected in 2001. Another measure of peak demand growth can be obtained by considering the average year to year MW load change. In Figure 3-2, the annual increase is 420 MW compared to about 360 MW per year in the previous forecast.

Resource Implications

SUFG's resource plans include both demand-side and supply-side resources to meet forecast demand. DSM impacts and interruptible load are netted from the demand projection and supply-side resources are added as necessary to maintain a 15 percent reserve margin. Although this approach provides a reasonable basis for estimating future electricity prices for planning purposes, it does not ensure that the resource plans are least cost.

Demand-Side Resources

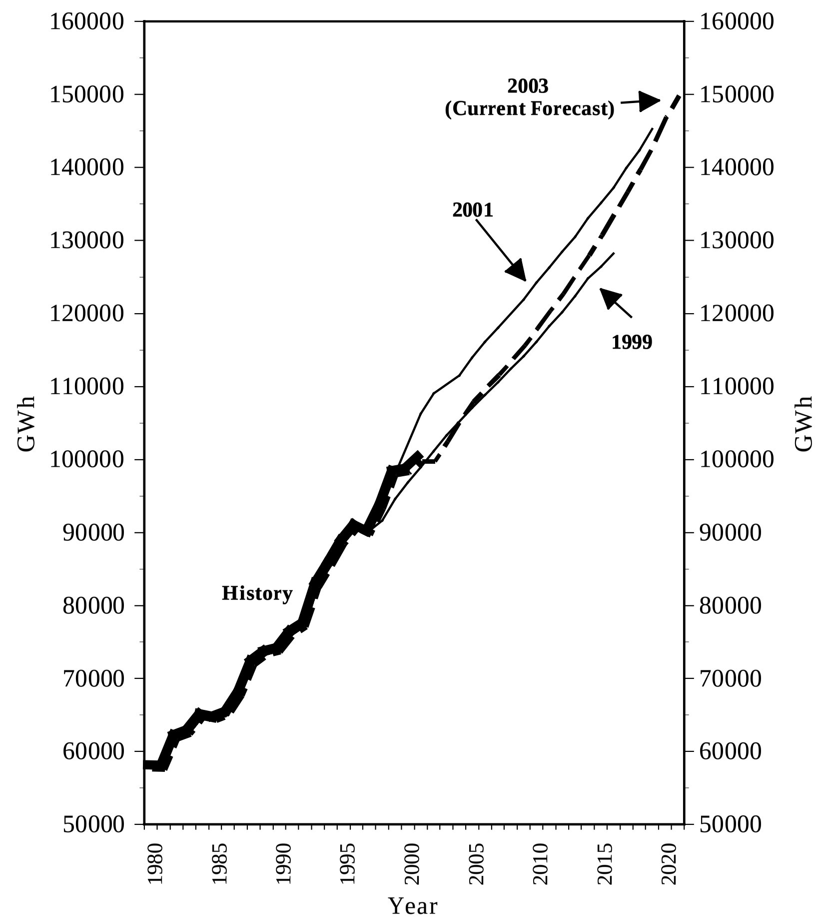
The current projection includes the energy and demand impacts of existing or planned utility-sponsored DSM programs. Incremental DSM programs, which include new programs and the expansion of existing

Figure 3-1. Indiana Electricity Requirements in GWh (Historical, Current and Previous Forecasts)

	Year of Forecast		
Year	1999	2001	2003
1990	73742	73742	73742
1991	76034	76034	76034
1992	77207	77207	77207
1993	82669	82669	82669
1994	85446	85446	85446
1995	88514	88514	88514
1996	90637	90637	90637
1997	90237	89773	89773
1998	91634	93429	93429
1999	94561	98001	98001
2000	96867	102116	98332
2001	98922	106257	99933
2002	101170	109014	99934
2003	103298	110294	102680
2004	105179	111515	105592
2005	107058	113997	108053
2006	108833	116118	109944
2007	110601	118017	111758
2008	112433	120012	113769
2009	114148	121892	115798
2010	116124	124225	118115
2011	118291	126317	120546
2012	120130	128418	122899
2013	122389	130497	125532
2014	124797	133048	128116
2015	126406	135161	130895
2016	128237	137244	133805
2017		139973	136839
2018		142342	139920
2019		145333	143145
2020			147067
2021			150013

Average Compound Growth Rates

Forecast Period	1997-16	2000-19	2002-21
	1.87	1.87	2.16



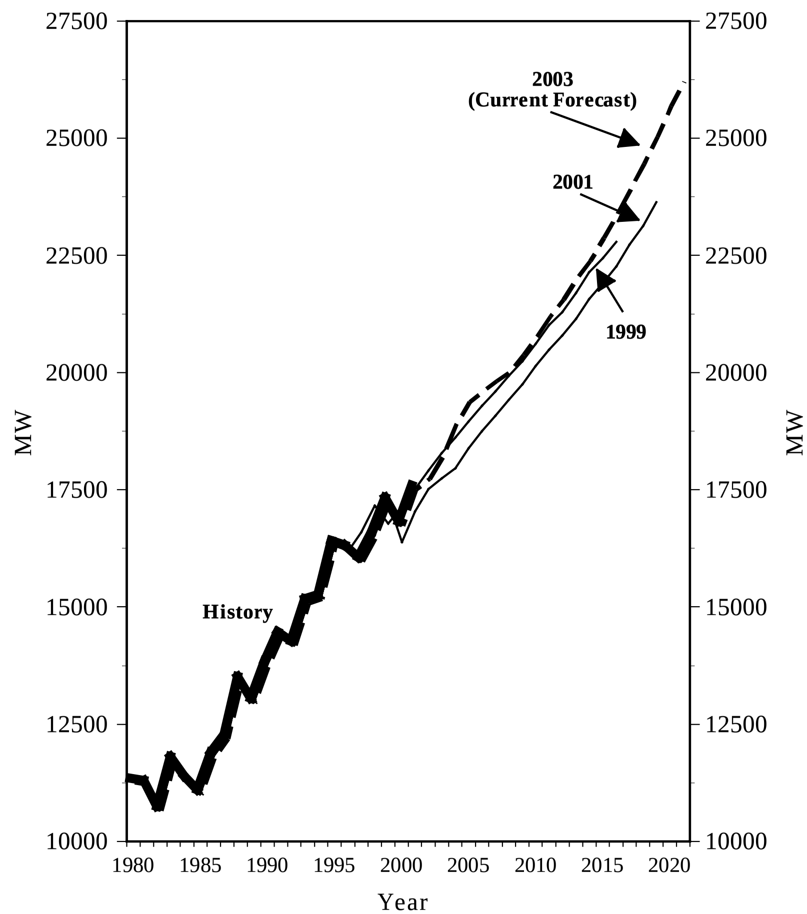
Notes: The shaded numbers in the table and the heavy line in the graph are historical values. (For an explanation on how SUFG arrives at these numbers, see Appendix A.)

Figure 3-2. Indiana Peak Demand Requirements in MW (Historical, Current and Previous Forecasts)

Year	1999	2001	2003
	Year of Forecast		
1990	13775	13775	13775
1991	14403	14403	14403
1992	14209	14209	14209
1993	15103	15103	15103
1994	15198	15198	15198
1995	16342	16342	16342
1996	16184	16254	16254
1997	16596	15993	15993
1998	17168	16527	16527
1999	16779	17266	17266
2000	17145	16383	16757
2001	17514	17038	17531
2002	17917	17519	17762
2003	18279	17739	18231
2004	18620	17964	18934
2005	18962	18385	19398
2006	19288	18748	19633
2007	19604	19080	19845
2008	19936	19422	20047
2009	20248	19756	20400
2010	20614	20143	20794
2011	21019	20493	21224
2012	21290	20795	21581
2013	21703	21146	22044
2014	22142	21568	22410
2015	22443	21912	22900
2016	22789	22269	23413
2017		22729	23945
2018		23133	24489
2019		23633	25057
2020			25709
2021			26231

Average Compound Growth Rates Forecast

Period	1997-16	2000-19	2002-21
	1.68	1.95	2.07



Notes: The shaded numbers in the table and the heavy line in the graph are historical values. (For an explanation on how SUFG arrives at these numbers, see AppendixA.)

programs, are projected to reduce peak demand by approximately 10 MW.

These DSM projections, which include new programs and the expansion of existing programs, do not include the reductions in peak demand due to interruptible load contracts with large customers. Approximately 840 MW of large load is classified as interruptible in this forecast, about 200 MW less than in the 2001 forecast.

Supply-Side Resources

SUFG's base resource plan includes all currently planned capacity changes. Planned capacity changes include: certified, rate base eligible generation additions, retirements, deratings due to nitrogen oxides (NOx) control retrofits and net changes in firm out-of-state purchases and sales. SUFG does not attempt to forecast long-term out-of-state contracts other than those currently in place. Generic firm wholesale purchases are then added at prices that reflect SUFG estimates of long-run average costs for these purchases as necessary during the forecast period to maintain a statewide 15 percent reserve margin. The 15 percent reserve margin is a "rule-of-thumb" that reflects recent national average reserve margins. Due to diversity in demand between utilities, a statewide 15 percent reserve margin occurs when individual utility reserve margins are roughly 11 percent.

Three types of generic firm wholesale purchases are included:

1. peaking purchases;
2. cycling purchases; and
3. coal-fired baseload purchases.

Based on projections of fuel and equipment costs and likely capacity factors for these units, SUFG would expect peaking units to be gas-fired combustion turbines (CT), cycling units to be gas-fired combined cycle (CC) plants, and baseload units to be pulverized coal (PC) plants meeting SO2 and NOx environmental requirements. Purchase price projections for each of these purchase types are set to recover the long-run cost of generating electricity from each unit.

Table 3-2 and Figure 3-3 show the statewide resource plan for the SUFG base scenario. Over the first half of the forecast period, about 3,700 MW of resource additions are required, with about half being of the base load variety. The net change in generation includes the retirement of units as reported in the utilities' 2001 IRP filings, changes in firm purchases and sales, and the addition of approved new capacity. Over the second half of the forecast period, an additional 6,000 MW of resources are required to maintain target reserves.

Previous forecasts have identified early resource needs of the peaking type. The recent addition of peaking generators to the statewide generation mix has reduced that need. While some additional peaking capacity will be needed in the future, this is the first SUFG forecast that identifies a substantial need for additional base load resources in the first few years (e.g., over 1,000 MW by 2008). The timing of the need for additional baseload resources is consistent with previous forecasts. Since this report comes two years after the 2001 forecast, the need is more immediate. This forecast also identifies a need for additional cycling resources in the short term.

While SUFG identifies resources needs in its forecasts, it does not advocate any specific means of meeting them. Required resources could be met through conservation measures, purchases from merchant generators or other utilities, construction of new facilities or some combination thereof. The best method for meeting resource requirements may vary from one utility to another.

Equilibrium Price and Energy Impact

The SUFG modeling system is designed to forecast an equilibrium price that balances electricity supply and demand. This is accomplished through the cost-price-demand feedback loop. The impact of this fea-

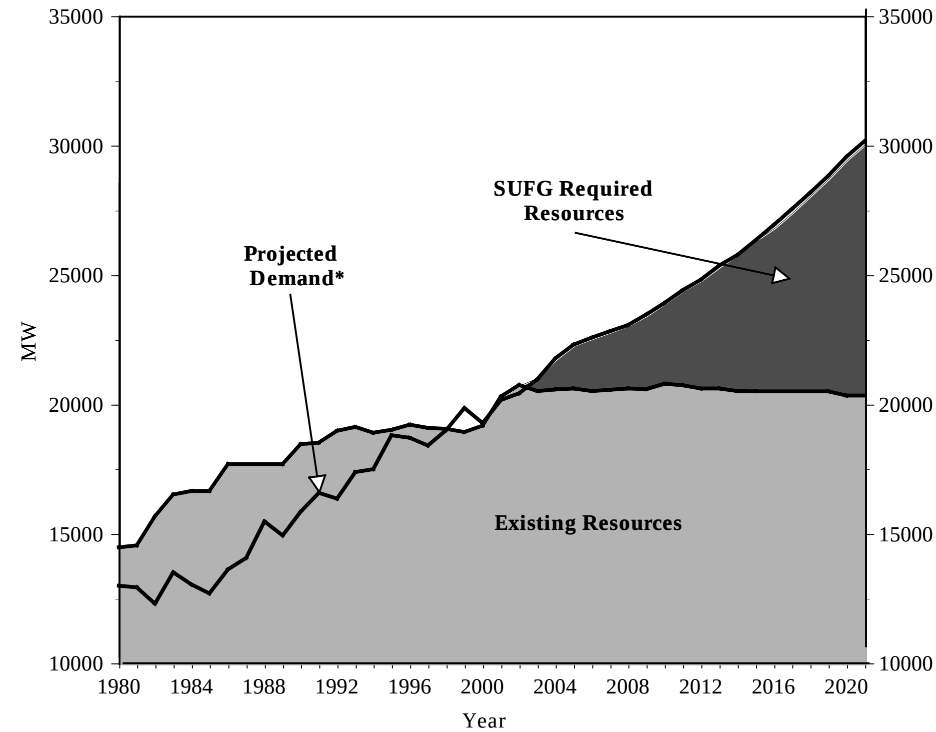
Table 3-2. Indiana Resource Plan (SUFG Base)

Year	Uncontrolled Peak Demand [1]	Interruptible Loads	Net Peak Demand [2]	Existing/ Approved Capacity [3]	Incremental Change in Capacity [4]	Projected Additional Capacity Requirements [5]				Total Capacity [6]	Reserve Margin
						Peaking	Cycling	Baseload	Total		
2001			17531	20294		0	0	0	0	20294	16
2002	18451	689	17762	20749	455	0	0	0	0	20749	17
2003	18945	714	18231	20506	-243	250	240	60	550	21056	15
2004	19698	764	18934	20572	66	280	670	240	1190	21762	15
2005	20177	779	19398	20613	41	410	840	440	1690	22303	15
2006	20416	784	19633	20513	-100	500	890	660	2050	22563	15
2007	20644	799	19845	20565	52	600	840	810	2250	22815	15
2008	20856	809	20047	20615	50	650	740	1060	2450	23065	15
2009	21229	829	20400	20587	-28	750	810	1300	2860	23447	15
2010	21638	844	20794	20792	205	710	840	1580	3130	23922	15
2011	22068	844	21224	20732	-60	820	990	1880	3690	24422	15
2012	22425	844	21581	20607	-125	920	1130	2160	4210	24817	15
2013	22888	844	22044	20607	0	1030	1220	2480	4730	25337	15
2014	23254	844	22410	20507	-100	1160	1330	2800	5290	25797	15
2015	23744	844	22900	20504	-3	1270	1420	3160	5850	26354	15
2016	24257	844	23413	20504	0	1310	1480	3540	6330	26834	15
2017	24789	844	23945	20504	0	1400	1540	3980	6920	27424	15
2018	25333	844	24489	20504	0	1520	1640	4410	7570	28074	15
2019	25901	844	25057	20504	0	1630	1730	4870	8230	28734	15
2020	26553	844	25709	20341	-163	1900	1760	5460	9120	29461	15
2021	27075	844	26231	20341	0	2020	1840	5870	9730	30071	15

Notes:

1. Uncontrolled peak demand is the peak demand without any interruptible loads being called upon.
2. Net peak demand is the peak demand are interruptible loads are taken into account.
3. Existing/approved capacity includes installed capacity plus approved new capacity plus firm purchases minus firm sales.
4. Incremental change in capacity is the change in existing/approved capacity from the previous year. The change is due to new, approved capacity becoming operational, retirements of existing capacity, and changes in firm purchases and sales..
5. Projected aditional capacity requirements is the cumulative amount of additional capacity needed to meet future requirements.
6. Total capacity requirements is the total statewide capacity required including existing/approved capacity and projected additional capacity requirements.

Figure 3-3. Indiana Resource Plan (SUFG Base)



*Projected Demand includes 15% Reserve Margin

ture on the forecast of electricity requirements can be significant.

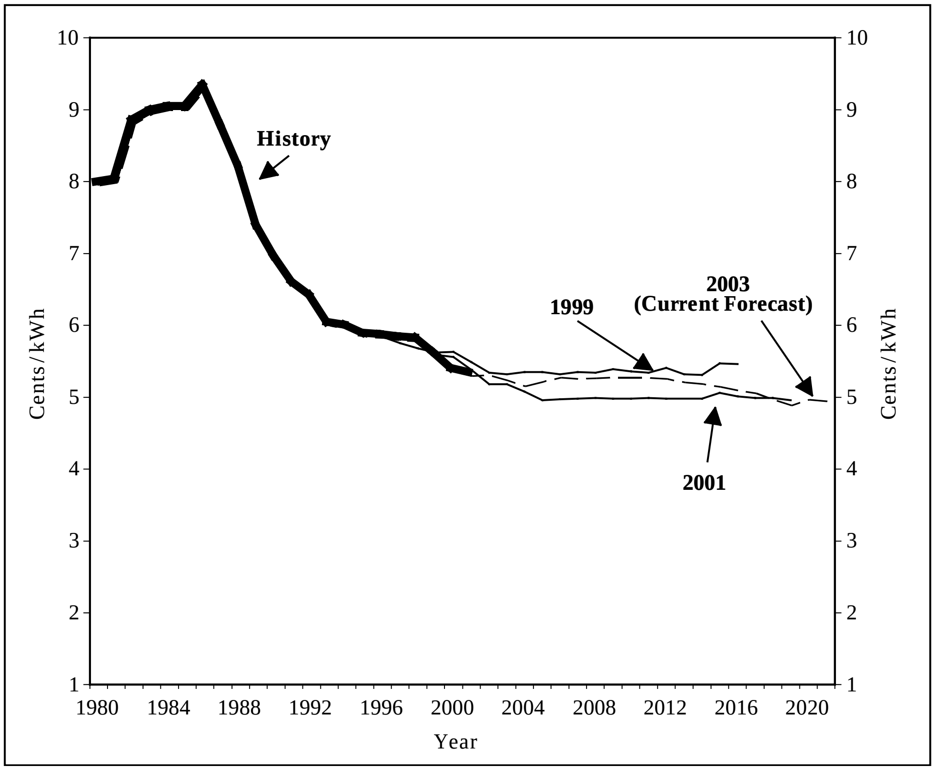
SUFG's base scenario equilibrium real electricity price trajectory is shown in Figure 3-4. Real prices are projected to remain steady for the first half of the forecast period and then slowly fall through the remainder of the forecast. Since the change in prices over the forecast horizon is small, price has little impact on the electricity requirements projection for this forecast.

SUFG's equilibrium price projections for two previous forecasts are also shown in Figure 3-4. The price projection labeled "1999" is the base case projection contained in SUFG's 1999 forecast and the one labeled "2001" is the base case projections from SUFG's 2001 report. For the prior price forecasts, SUFG rescaled the original price projections to 2001 dollars (from 1996 dollars for the 1999 projection, and from 1999 dollars for the 2001 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

Two major factors primarily determine the differences among the price projections in Figure 3-4; namely, the capital cost assumptions for new generation equipment and the cost of controlling emissions from coal-fired generation facilities. Other factors such as energy and demand growth as well as fossil fuel price assumptions, especially coal, also influence the trajectory of future prices. More detail regarding the assumptions and procedures used in SUFG's 1999 and 2001 price forecasts may be found in previous SUFG reports.

SUFG's projected generation additions are determined from a statewide as well as individual utility perspective. Thus, SUFG's integrated electricity modeling system develops a base resource plan and electricity price projections for each utility.

Figure 3-4. Indiana Real Price Projections (2001 Dollars) (Historical, Current and Previous Forecasts)



Low and High Scenarios

SUFG has constructed alternative, low and high growth scenarios. These low probability scenarios are used to indicate the forecast range, or dispersion of possible future trajectories. Figures 3-5 and 3-6 provide the statewide electricity requirements and peak demand projections for the base, low and high scenarios. As shown in those figures, the annual growth rates for the low and high scenarios are about 0.90 percent lower and 0.90 percent higher than the base scenario for both energy requirements and peak demand. These differences are due to economic growth assumptions in the scenario-based projections.

Resource and Price Implications Of Low and High Scenarios

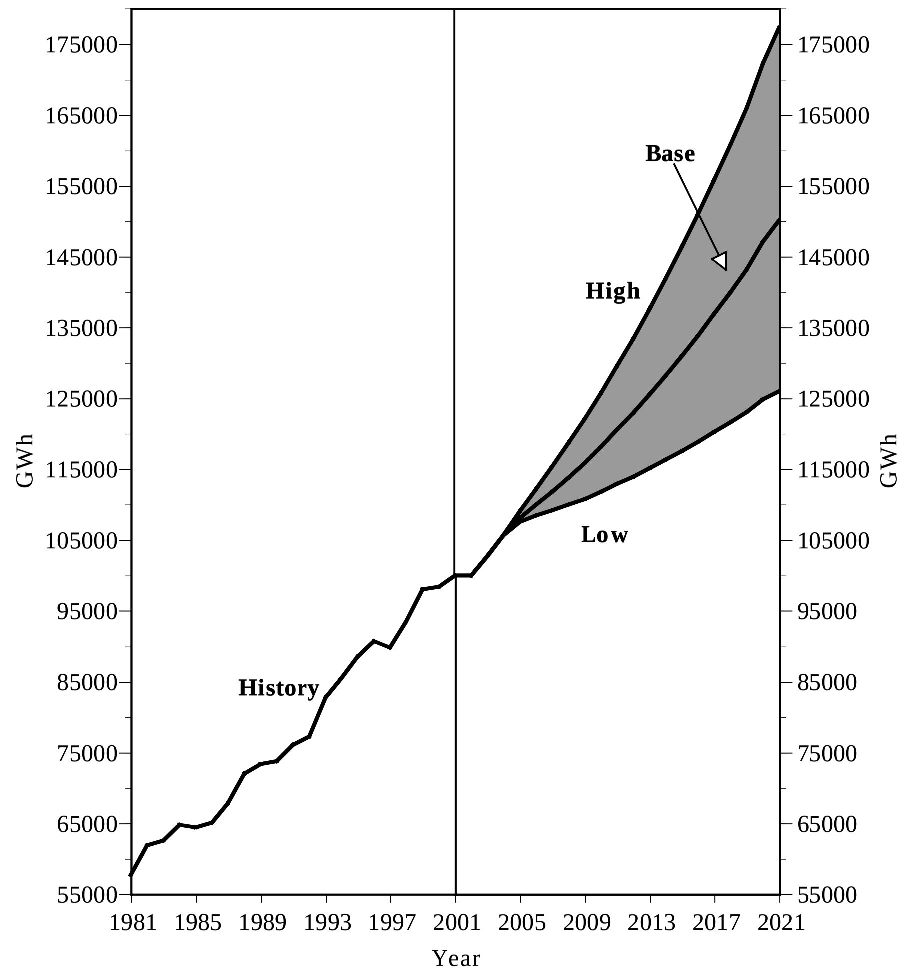
Resource plans are developed for the low and high scenarios using the same methodology as the base plan. Demand-side resources, including interruptible loads, are the same in all three scenarios, as are retirements. Table 3-3 shows the statewide supply-side additions for each scenario. Approximately 15,000 MW over the horizon are required in the high scenario compared to less than 5,000 MW in the low scenario. By the end of the forecast period, electricity prices in the high case are 7 percent higher than in the base case. This is because nearly 5,300 MW of additional wholesale purchases are acquired relative to the base scenario. Prices in the low scenario are only about 5 percent lower than the base scenario despite significantly fewer resource additions. This is caused by the lack of sales growth, which in addition to delaying the need for resource additions, results in allocation of fixed costs of existing generation resources and firm purchases to fewer kWh.

Figure 3-5. Indiana Electricity Requirements by Scenario in GWh

Year	Base	Low	High
1996	90637	90637	90637
1997	89773	89773	89773
1998	93429	93429	93429
1999	98001	98001	98001
2000	98332	98332	98332
2001	99933	99933	99933
2002	99934	99933	99944
2003	102680	102678	102701
2004	105592	105589	105625
2005	108053	107473	108960
2006	109944	108379	112158
2007	111758	109098	115337
2008	113769	109938	118676
2009	115798	110748	122015
2010	118115	111783	125719
2011	120546	112882	129560
2012	122899	113879	133374
2013	125532	115091	137562
2014	128116	116252	141799
2015	130895	117477	146299
2016	133805	118808	150954
2017	136839	120204	155772
2018	139920	121553	160717
2019	143145	122975	165863
2020	147067	124816	172223
2021	150013	125961	177230

Average Compound Growth Rates

Selected Periods	Base	Low	High
1980-85	2.22	2.22	2.22
1985-90	2.75	2.75	2.75
1990-95	3.72	3.72	3.72
1995-00	2.13	2.13	2.13
2000-05	1.90	1.79	2.07
2002-21	**2.16**	**1.23**	**3.06**



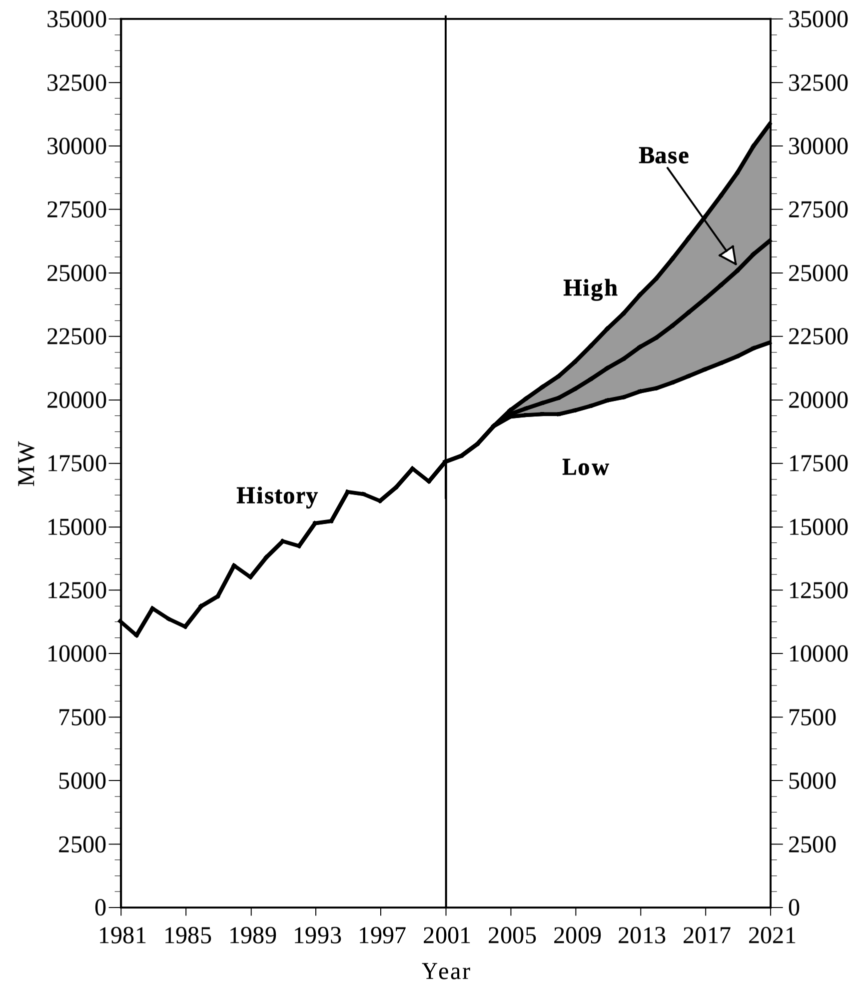
Notes: The shaded numbers in the table and the heavy line in the graph are historical values. (For an explanation on how SUFG arrives at these numbers, see Appendix A.)

Figure 3-6. Indiana Peak Demand Requirements by Scenario in MW

Year	Base	Low	High
1996	16254	16254	16254
1997	15993	15993	15993
1998	16527	16527	16527
1999	17266	17266	17266
2000	16757	16757	16757
2001	17531	17531	17531
2002	17762	17762	17764
2003	18231	18231	18235
2004	18934	18933	18940
2005	19398	19300	19559
2006	19633	19370	20021
2007	19845	19401	20469
2008	20047	19406	20897
2009	20400	19555	21471
2010	20794	19735	22098
2011	21224	19941	22768
2012	21581	20071	23373
2013	22044	20298	24102
2014	22410	20423	24746
2015	22900	20655	25526
2016	23413	20903	26331
2017	23945	21162	27164
2018	24489	21416	28023
2019	25057	21685	28914
2020	25709	22000	29968
2021	26231	22228	30832

Average Compound Growth Rates

Selected Periods	Base	Low	High
1980-85	-0.45	-0.45	-0.45
1985-90	4.55	4.55	4.55
1990-95	3.48	3.48	3.48
1995-00	0.50	0.50	0.50
2000-05	2.97	2.87	3.14
2002-21	**2.07**	**1.19**	**2.94**



Notes: The shaded numbers in the table and the heavy line in the graph are historical values. (For an explanation on how SUFG arrives at these numbers, see Appendix A.)

Table 3-3. Indiana Resource Requirements in MW (SUFG Scenarios)

Year	Base				Low				High			
	Peaking	Cycling	Base Load	Total	Peaking	Cycling	Base Load	Total	Peaking	Cycling	Base Load	Total
2002	0	0	0	0	0	0	0	0	0	0	0	0
2003	250	240	60	550	250	240	60	50	250	240	60	550
2004	280	670	240	1190	280	670	240	550	280	680	250	1210
2005	410	840	440	1690	400	810	390	1190	480	880	530	1890
2006	500	890	660	2050	410	840	500	1600	590	960	960	2510
2007	600	840	810	2250	490	760	500	1750	740	960	1270	2970
2008	650	740	1060	2450	490	640	570	1750	820	900	1700	3420
2009	750	810	1300	2860	570	670	660	1700	980	1010	2110	4100
2010	710	840	1580	3130	470	670	780	1900	980	1090	2540	4610
2011	820	990	1880	3690	510	770	920	1920	1150	1280	3020	5450
2012	920	1130	2160	4210	580	880	1030	2200	1290	1480	3500	6270
2013	1030	1220	2480	4730	630	920	1180	2490	1430	1580	4100	7110
2014	1160	1330	2800	5290	690	970	1330	2730	1570	1700	4670	7940
2015	1270	1420	3160	5850	760	1020	1480	2990	1740	1810	5300	8850
2016	1310	1480	3540	6330	790	1030	1600	3260	1880	1910	5880	9670
2017	1400	1540	3980	6920	850	1090	1790	3420	2050	2020	6560	10630
2018	1520	1640	4410	7570	910	1130	1960	3730	2240	2120	7280	11640
2019	1630	1730	4870	8230	980	1200	2160	4000	2400	2280	7970	12650
2020	1900	1760	5460	9120	1210	1220	2430	4340	2760	2450	8810	14020
2021	2020	1840	5870	9730	1270	1270	2570	4860	2930	2590	9490	15010

CHAPTER 4
MAJOR FORECAST INPUTS AND ASSUMPTIONS

Introduction

The models SUFG utilizes to project electric energy sales, peak demand and prices require external, or exogenous, assumptions for several key inputs. Some of these input assumptions pertain to the level of economic activity, population growth and age composition for Indiana. Other assumptions include fossil fuel prices, which are used to generate electricity and compete with electricity to provide end-use service. Also included are estimates of the energy and peak demand reductions due to utility load management programs.

This section describes SUFG's scenarios, presents the major input assumptions and provides a brief explanation of forecast uncertainty.

Macroeconomic Scenarios

The assumptions related to macroeconomic activity determine, to a large degree, the essence of SUFG's forecasts. These assumptions determine the level of various activities such as personal income, employment and manufacturing output, which in turn directly influence electricity consumption. Due to the importance of these assumptions and to illustrate forecast uncertainty, SUFG used alternative projections or scenarios of macroeconomic activity provided by CEMR.

- The *base scenario* is intended to represent the electricity forecast that is "most likely" and has an equal probability of being high or low.
- The *low scenario* is intended to represent a plausible lower bound on the electricity sales forecast and has a low probability of occurrence.
- The *high scenario* is intended to represent a plausible upper bound on the electricity sales forecast and also has a low probability of occurrence.

These scenarios are developed by varying the major forecast assumptions, i.e., Indiana's share of the national economy.

Economic Activity Projections

National and state economic projections are produced by the CEMR twice each year. For this forecast, SUFG adopted CEMR's August 2002 economic projections as its base scenario. CEMR also produced high and low growth alternatives to the base projection for SUFG's use in its high and low scenarios.

CEMR developed these projections from its U.S. and Indiana macroeconomic models. The Indiana economic forecast is generated in two stages. First, a set of exogenous assumptions affecting the national economy are developed by CEMR and input to its model of the U.S. economy. Second, the national economic projections from this model are input to the Indiana model that translates the national projections into projections of the Indiana economy.

The CEMR model of the U.S. economy is a large scale quarterly econometric model. Successive versions of the model have been used for more than 15 years to generate short-term forecasts. The model has a detailed aggregate demand sector that determines output. It also has a fully specified labor market submodel. Output determines employment, which then affects the availability of labor. Labor market tightness helps determine wage rates, which, along with employment, interest rates and several other variables determine personal income. Fiscal policy variables, such as spending levels and tax rates, interact with income to determine federal, state and local budgets. Monetary policy variables interact with output and price variables to determine interest rates.

A major input to CEMR's Indiana model is a projection of total U.S. employment, which is derived from CEMR's model of the U.S. economy.

MAJOR FORECAST INPUTS AND ASSUMPTIONS

The Indiana model has four main modules. The first disaggregates total U.S. employment into 19 manufacturing and 11 non-manufacturing sectors. The second module then projects the share of each industry in Indiana. Additional relationships are used to project average weekly hours and average hourly earnings by industry. These are used with employment to calculate a total wage bill. The third module projects the remaining components of personal income. In the fourth module, labor productivity combined with employment projections is used to calculate real Gross State Product (GSP), or output, by industry.

The main exogenous assumptions in the national projections used in the CEMR forecast are:

- Federal tax rates and grants to state and local governments will increase slightly, but transfer payments show strong growth especially in the last half of the forecast period. As a result, the federal budget maintains a modest deficit through most of the forecast horizon, but the deficit increases as transfer payments increase at the end of the forecast horizon.
- Imports continue to exceed exports, but at a slowing rate (measured in dollars), which leads to a continued, but narrowing negative net trade balance.

As a result of these assumptions, real Gross Domestic Product (GDP) for the U.S. economy is projected to grow at an average annual rate of 3.19 percent and U.S. employment growth averages 0.98 percent over the 2002 to 2021 period.

In Indiana, total employment is projected to grow at an average annual rate of 1.24 percent. The key economic projections are:

- Real personal income (the residential sector model driver) is expected to grow at a 2.36 percent annual rate.
- Non-manufacturing employment (the commercial sector model driver) is expected to average a 1.79 percent annual growth rate over the forecast horizon.
- Despite the continued decline of manufacturing employment, manufacturing GSP (the industrial sector model driver) is expected to rise at a 1.50 percent annual rate as gains in productivity offset declines in employment.

CEMR's macroeconomic projections reflect a continuation of the economic slowdown for the first few years of the forecast. Real Indiana personal income growth is sluggish at 1.67 percent per year through 2007 compared to 2.36 percent per year for the entire forecast horizon. Indiana non-manufacturing employment actually grows slightly faster in the first few years of the forecast, but Indiana total employment growth remains constant at about 1.25 percent per year as Indiana manufacturing employment declines. Manufacturing output (real GSP) grows at an annual rate of 1.33 percent early in the forecast compared to 1.50 percent per year over the entire forecast horizon. Indiana manufacturing output for 2003 is projected to be roughly the same as that for 2001 and 2002, but output levels similar to that of 2000 are not projected until 2007.

A summary comparison of CEMR’s projections used in SUFG’s previous and current electricity projections and historical growth rates for recent historical periods is provided in Table 4-1.

To capture some of the uncertainty in energy forecasting, CEMR provided a low and high growth alternative to its base economic projection. In effect, the alternatives describe a situation in which Indiana either loses or gains shares of national industries compared to the base projection. In the high growth alternative, the Indiana average growth rate of personal income is increased by 1.15 percent per year (to 3.51), non-manufacturing employment growth increases almost 0.75 percent (to 2.53) while Indiana real manufacturing GSP growth is raised more than 1.05 percent to 2.58. In the low growth alternative, the average rates of real personal income, non-manufacturing employment and real manufacturing GSP are reduced by similar amounts (to 1.91, 0.94 and 0.16 respectively.)

Demographic Projections

Household projections are a major input to the residential energy forecasting model. The SUFG forecasting system includes a housing model which utilizes population and income assumptions to project households or customers.

The population projections utilized in SUFG's electricity forecasts were obtained from the Indiana Business Research Center at Indiana University (IBRC). The IBRC population growth forecast for Indiana is 0.25 percent a year. This projection was developed in 1993 and includes projections of county population by age group. SUFG also reviewed a second set of population projections, developed in the early 1990s by the Family Research Center, Department of Sociology at Indiana University-Purdue University, Indianapolis (IUPUI). Both studies project population to grow less rapidly in Indiana than for the nation. Population projection increases are marginally higher in the IBRC forecast.

Population growth is low during the projection period because the age distribution in Indiana is skewed from young adults of childbearing age to older adults with higher mortality rates. Fertility rates in the state have been below replacement level since the mid-1970s and are projected to decline even further because of the net out migration of young adults during the 1980s. As birthrates drop and the existing population grows older, deaths exceed births and the state's population begins to naturally decrease by about 2020 given that the trend continues.

Indiana population growth has slowed markedly in recent years. The number of people over age 35 (the groups with fewer occupants per household) is projected to grow more rapidly than the total population. Thus, household formations are expected to grow more rapidly than total population.

The historical growth of household formations (number of residential customers) has slowed down significantly from slightly over 2 percent during the late 1960s and early 1970s to about 1 percent currently. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of about 0.70 percent over the forecast period.

Fossil Fuel Price Projections

The price of fossil fuels such as coal, natural gas and oil affects electricity demand in separate and opposite ways. To the extent that any of these fuels are used to generate electricity, they are a determinant of average electricity prices. Electricity generation in Indiana is currently fueled almost entirely by coal. Thus, when coal prices increase, electricity prices in Indiana rise and electricity demand falls, all else being equal. On the other hand, fossil fuels compete directly with electricity to provide end-use services, i.e., space and water heating, process use, etc. When prices for these fuels increase, electricity becomes relatively more attractive and electricity demand tends to rise, all else being equal. As fossil fuel prices increase, the impacts on electricity demand are somewhat offsetting. The net impact of these opposite forces depends on their impact on utility costs, the responsiveness of customer demand to electricity price changes and the availability and competitiveness of fossil fuels in the end-use services markets. The SUFG modeling system is designed to simulate each of these effects as well as the dynamic interactions among all effects.

In this forecast, SUFG has used January 2003 fossil fuel price projections from EIA for the East North Cen-

Table 4-1. Growth Rates for Current and Past CEMR Projections of Selected Economic Activity Measures (%)

	Short-Run History for Selected Recent Periods				Long-Run Forecast Feb. 2001	Long-Run Forecast Aug. 2002
	1980-1985	1985-1990	1990-1995	1995-2000	2000-2019	2002-2021
United States						
Real Personal Income	3.30	2.95	2.04	4.08	3.22	3.04
Total Employment	1.50	2.36	1.38	2.37	0.96	0.98
Real Gross Domestic Product	3.13	3.25	2.38	4.35	3.45	3.19
Personal Consumer Expenditure Deflator	5.14	3.79	2.77	1.87	2.70	2.28
Indiana						
Real Personal Income	1.47	2.50	2.48	3.37	2.62	2.36
Employment:						
Total	0.22	2.84	1.91	1.22	1.17	1.24
Manufacturing	-1.49	0.91	1.40	0.07	-0.80	-1.17
Non-Manufacturing						
Real Gross State Product	1.17	3.82	2.20	1.97	1.72	1.79
Total	6.65	6.17	5.83	4.78	1.60	2.14
Manufacturing	5.84	4.76	7.95	4.68	1.41	1.50
Non-Manufacturing	7.04	6.81	4.86	4.84	1.68	2.41

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Outlooks."

tral Region of the U.S. All SUFG projections are in terms of real prices (2001 dollars), i.e., projections with the effects of inflation removed. The general patterns of the fossil fuel price projections are that:

- Coal prices will decline slightly in real terms throughout the entire forecast horizon.
- Gas price projections for all customers decrease slightly through 2006 and increase moderately over the remainder of the forecast horizon.
- Distillate prices exhibit a pattern similar to natural gas over the entire forecast horizon, with a more pronounced decline early in the horizon and a stronger increase in the last three-fourths of this horizon.

The pattern of fossil fuel price projections is presented as growth rates in Table 4-2 for selected periods.

Demand-Side Management and Interruptible Loads

Demand-side management (DSM) refers to a variety of utility-sponsored programs designed to influence customer electricity usage in ways that produce desired changes in the utility's loadshape, i.e., changes in the time pattern or magnitude of a utility's load. These programs include energy conservation programs that reduce overall consumption and load shifting programs that move demand to a time when overall system demand is lower.

Incremental DSM, which includes new programs and the expansion of existing programs, require ad-

Table 4-2. Growth Rates for Real Fossil Fuel Price Projections (%)

	2002-2006 "Decline"	2006-2021 "Trend"	2002-2021 "Horizon"
Coal			
Electric Utilities	-0.16	-0.61	-0.51
Industrial Customers	-0.58	-0.65	-0.63
Natural Gas			
Electric Utilities	0.39	2.42	1.99
Residential Customers	-0.23	0.69	0.49
Commercial Customers	-0.42	0.97	0.67
Industrial Customers	-0.22	1.49	1.13
Distillate			
Electric Utilities	-3.16	1.72	0.67
Residential Customers	-1.44	1.22	0.65
Commercial Customers	-2.96	1.64	0.66
Industrial Customers	-2.57	1.49	0.62

Source: EIA Annual Energy Outlook, 2003 DOE/EIA-0383(2003), January 2003 Supplement Tables.

justments to be made in the forecast. These adjustments are made by changing the utility's demand by the appropriate level of energy and peak demand for the DSM program. DSM programs that were in place in 2001 are considered to be embedded in the calibration data, so no adjustments are necessary.

Interruptible loads, such as large customers who agree to curtail a fixed amount their demand during critical periods in exchange for more favorable rates, are typically treated differently than traditional DSM. Interruptible loads are subtracted from the utility's peak demand in order to determine the amount of new capacity required.

Table 4-3 shows the amount of embedded and incremental DSM in terms of energy and peak demand reductions, as well as the amount of interruptible load available in Indiana. These estimates are derived from utility integrated resource plan (IRP) filings and from information collected by EIA. While estimates of incremental DSM has declined dramatically in recent years (from 900 MW in the 1996 forecast to 28 MW in this forecast), interruptible loads have increased (from 510 MW in 1996 and 840 MW in this forecast).

The decline in incremental DSM is primarily due to two factors. First, as the new DSM programs of the 1990s matured, the energy and peak demand reductions became embedded in the calibration data with

Table 4-3. Energy and Peak Demand Reductions

Embedded DSM		Incremental DSM		Interruptible
MW	GWh	MW	GWh	MW
180	890	28	17	840

little opportunity for additional incremental reductions. Second, many utilities reevaluated their DSM programs in the face of the changing structure of the electricity industry in the late 1990s.

The interruptible load numbers include both traditional interruptible contracts, whereby the customer shuts off its load when certain criteria are met, and buy through contracts, whereby the customer has the option of shutting off the load or purchasing the power at the wholesale price. For both types of interruptible load, the utility does not have to acquire additional peak generating capacity ahead of time to meet that load. Therefore, interruptible and buy through loads are subtracted from total peak demand for capacity planning purposes. The peak demand projections in this report are net of both types of interruptible loads; that is those loads have been removed from the projections.

When analyzing wholesale markets, the distinction between interruptible and buy through loads becomes more important. Traditional interruptible loads may be assumed to be absent from the system during time of high demand and prices, while buy through loads may still be present, with the higher prices passed directly to the customer.

Forecast Uncertainty

There are three sources of uncertainty in any energy forecast:

1. exogenous assumptions,
2. stochastic model error, and
3. non-stochastic model error.

Projections of future electricity requirements are conditional on the projections of exogenous variables. Exogenous variables are those for which values must be assumed or projected by other models or methods outside the energy modeling system. These exogenous assumptions, which include demographics, economic activity and fossil fuel prices, are not known with certainty. Thus, they represent a major source of uncertainty in any energy forecast.

Stochastic error is inherent in the structure of any forecasting model. Sampling error is one source of stochastic error. Each set of observations (the historical data) from which the model is estimated constitutes a sample. When one considers stochastic model error, it is implicitly assumed that the model is correctly specified and that it is using correctly measured data. Under these assumptions the error between the estimated model and the true model (which is always unknown) has certain properties. The expected value of the error term is equal to zero. However, for any observation in the sample, it may be positive or negative. The errors from a number of samples follow a pattern, which is described as the normal probability distribution, or bell curve. This particular normal distribution has a zero mean, and an unknown, but estimable variance. The magnitude of stochastic model error is directly related to the magnitude of the estimated variance of this distribution. The greater the variance is, the larger the error will be.

In practice, virtually all models are less than perfect. Non-stochastic model error results from specification errors, measurement errors and/or use of an inappropriate estimation method.

RESIDENTIAL ELECTRICITY SALES

Overview

SUFG uses both econometric and end-use models of residential electricity sales. These different modeling approaches have specific strengths and complement each other. The econometric model is used to project the number of customers in two groups, those with and those without electric space heating systems, as well as average electricity use by each customer groups. The SUFG staff originally developed the econometric model in 1987 when it was estimated from utility specific data. Since then, it has been reestimated three times, once in 1988 and again in 1994 and 1996. In addition, SUFG has acquired a proprietary end-use model, Residential End-Use Energy Modeling System (REEMS), which blends econometric and engineering methodologies to project energy use on a very disaggregated basis. REEMS is a descendant of the first generation of end-use models developed at Oak Ridge National Labs (ORNL) during the late 1970s.

Although these modeling approaches are complementary, these two models forecast very differently. Given the same set of primary inputs, the econometric model projects nearly twice as much growth as the end-use model. Experience has shown the econometric model to be much more accurate. For this reason, SUFG continues to rely on its econometric model to project residential electricity sales.

A general description of the residential econometric model follows, along with a brief historical perspective on residential electricity consumption trends in Indiana.

Historical Perspective

The growth in residential electricity consumption has generally reflected changes in economic activity, i.e., real household income, real energy prices and total households. Each of four recent periods has been characterized by distinctly different trends in these market factors and in each case, residential electricity sales growth has reflected the change in market conditions. Since 1999 economic activity has slowed dramatically with a resultant decline in electric energy sales growth (see Figure 5-1).

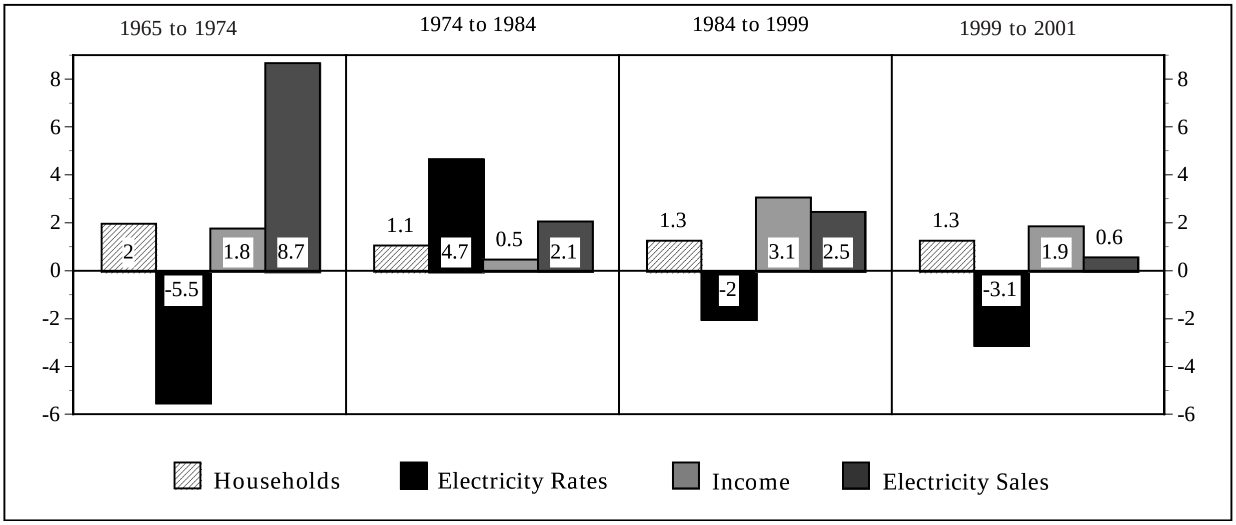
The explosion in residential electricity sales (nearly 9 percent per year) during the decade prior to the Organization of Petroleum Exporting Countries (OPEC) oil embargo in 1974 coincided with the economic stimuli of falling prices (nearly 6 percent per year in real terms) and rising incomes (nearly 2 percent per year in real terms). This period also was marked by a boom in the housing industry as residences increased at an average rate of 2 percent per year.

In the decade following the embargo, the growth in residential electricity sales slowed dramatically. Except for some softening in electricity prices during 1979-81, real electricity prices climbed at approximately the same rate during the post-embargo era as they had fallen during the pre-embargo era. This resulted in a swing in electric prices of more than 10 percent. Growth in real household income was a miniscule 0.5 percent, less than one-third that seen in the previous period. The housing market also went from boom to bust, averaging only half the growth of the pre-embargo period. This turnaround in economic conditions and electricity prices is reflected in the dramatic decline in the growth of residential electricity sales from nearly 9 percent per year prior to 1974, to just 2 percent per year over the next decade.

Events turned again during the mid-1980s. Real household income grew at more than the pre-embargo rate, 3.1 percent per year. Real electricity prices declined 2.0 percent per year at one third the pre-embargo rate. Households grew only at a slightly higher rate than in the post-embargo decade, about 1.3 percent per year. Despite these more favorable market conditions, annual sales growth increased only 0.4 percent to 2.5 percent per year.

Several market factors contributed to the small difference in sales growth between the post-embargo and more recent period. First, and perhaps most importantly, is the difference in the availability and price of

Figure 5-1. State Historical Trends in the Residential Sector (Annual Percent Change)



natural gas between the two periods. Restrictions on new natural gas hook-ups during the post-embargo period and supply uncertainty caused electricity to gain market share in major end-use markets previously dominated by natural gas, i.e., space heating and water heating. More recently, plentiful supply and falling natural gas prices through 1999 have caused natural gas to recapture market share. Next in importance are equipment efficiency standards and the availability of more efficient appliances. Appliance efficiency improvement standards did not begin until late in the post-embargo era. Lastly, appliance saturations tend to grow more slowly as they approach full market saturation and the major residential end uses are nearing full saturation.

In the last few years (1999 to present) residential household growth has remained at the 1.3 percent annual rate observed over the 1984 to 1999 period, real electric rates have continued to decline, but the growth in both personal income and electricity consumption, while positive, has slowed markedly. While these more recent observations are based on very short periods of time, the effect of the economic slowdown appears obvious.

Model Description

An important consideration in modeling residential electricity sales is how best to disaggregate electricity use. The SUFG econometric model divides residential customers into two customer groups: electric and non-electric space heating. Sales for each customer group are estimated by multiplying projected number of customers in each group by their estimated kWh consumption per customer. This market segmentation is necessary since significant differences exist in the appliance portfolios of typical electric and non-electric space heating customers. Households with electric space heating systems tend to have much higher saturations of electric water heating, cooking and clothes drying, as well as central air conditioning. For these reasons, electric space heating customers consume almost twice the amount of electricity as non-electric space heating customers. In addition to these differences, historical consumption trends for these two customer groups, as shown in Panels D and E of Figure 5-2, have tended to move in opposite directions as well. Yet another reason for dividing residential customers into electric and non-electric space heating groups is shown in Panel B of Figure 5-2. The growth of electric space heating was quite rapid throughout both the pre- and post-embargo period. Panel A of Figure 5-2 depicts the falling price of electricity relative to natural gas during both periods. Relative electricity and gas prices bottomed out in 1983 and since then, the penetration of electricity in the space heating market has fallen by more than half.

Space Heating Fuel Choice Model

A logit model, based on relative fuel costs, is used to project space heating fuel choice (electric vs. non-electric). This model was estimated from data for the five Indiana IOUs. The dependent variable in this model, referred to as a logit, is the ratio of electricity's share of new space heating systems to that of all other fuels. Market share, or penetration, is defined as the change in electric space heating customers as a fraction of net new customers. The advantages of modeling penetration rather than saturation are that penetration captures current activity, is independent of the rate of customer growth and exhibits greater year-to-year variation. Under SUFG's base case assumptions of stable electricity prices and increasing natural gas prices, the fuel choice model projects the penetration of electric space heating to average about 45 percent over the forecast horizon (for the five IOUs combined). This results in space heating saturation of 25 percent by the end of the forecast horizon (Panel C).

After projecting the share of new residential customers choosing electric space heating systems, the residential econometric model next projects average electricity consumption for each customer group.

Average kWh Sales: Non-Electric Heating Customers

About 80 percent of all residential customers are non-electric heating customers. Prior to 1974, average electricity consumption by these customers increased about 6 percent per year. Since 1974, average use has increased moderately, averaging about 0.5 percent per year from 1975-85 and about 1.6 percent thereafter.

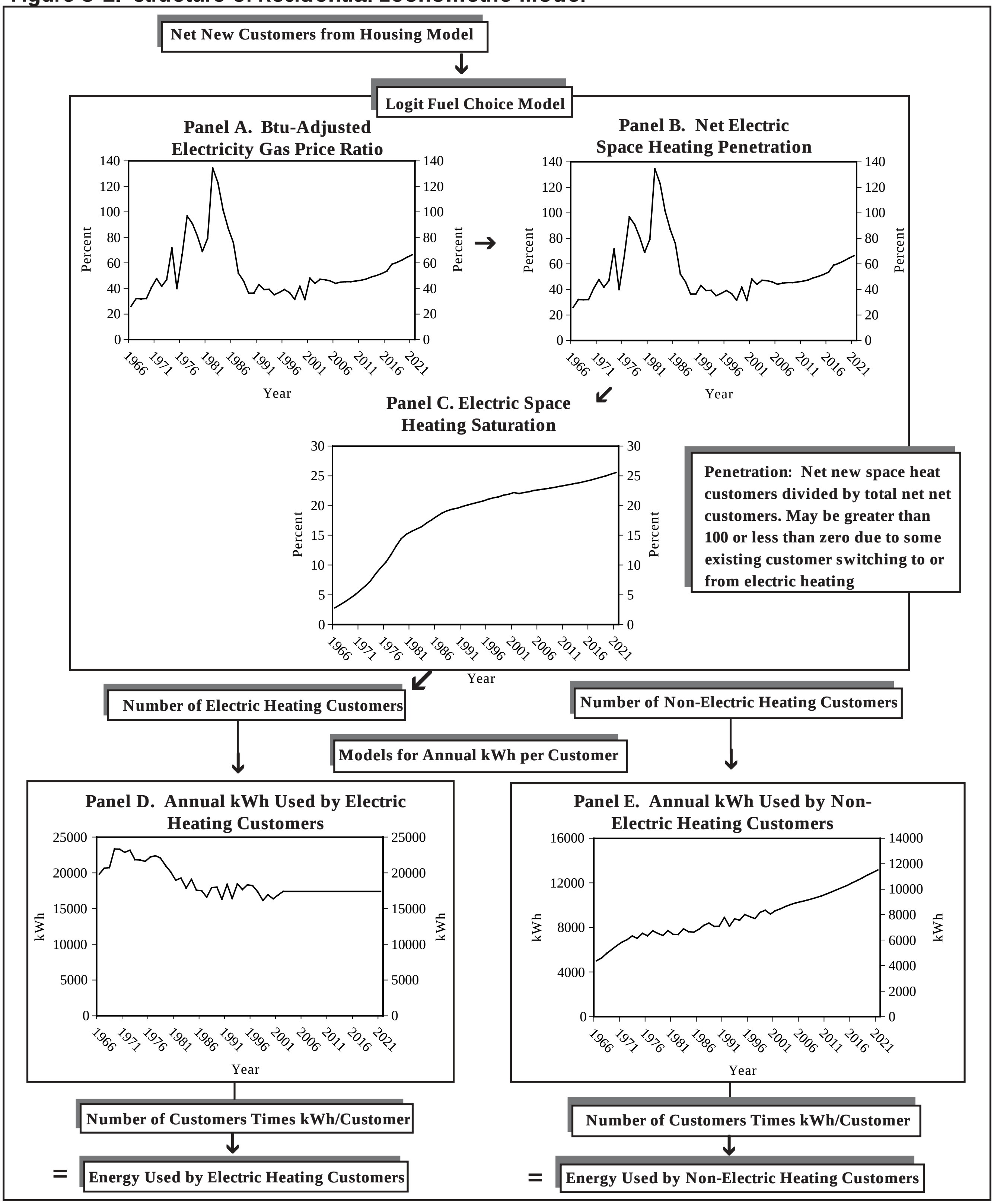
A robust econometric demand model, known as the log-log expenditure share model, is used to estimate the demand for electricity by non-electric heating customers. This relationship is capable of picking up emerging nonlinearities or saturation effects not detected by ordinary demand models. This is especially important since the model is used to generate long-range forecasts.

Average kWh Sales: Electric Space Heating Customers

Average sales to electric space heating customers declined significantly throughout the 1970s and 1980s (see Panel D in Figure 5-2). This downward trend is most likely attributable to lower consumption by new electric space heating customers (better insulated buildings, heat pumps and a changing mix of type and size of new electrically heated homes) than it is to decreases in consumption by existing customers (i.e., lower thermostat settings and envelope retrofits), although the latter has most likely occurred as well. The application of econometric analysis to capture these effects is not likely to provide reliable or even plausible results on an aggregate level. The heterogeneity among customers over time is too great. SUFG performed limited econometric analysis of this component without success.

Consumption data for the last several years indicate that the rapid decline in average energy consumption by electric space heating customers has leveled off after falling nearly 20 percent between the late 1970s and the mid-1980s. A review of the thermal integrity and electric space heating technology curves from the residential end-use model suggested that savings beyond 20 percent would require a substantial increase in the real price of electricity. Given this result, in combination with the outlook for constant or declining real electricity prices during the forecast period and the

Figure 5-2. Structure of Residential Econometric Model



apparent leveling off of the decline in usage in recent years, SUFG assumes that the space heating component of a space heating customer's consumption will remain constant throughout the forecast period at about 7,500 kWh per year.

The non-space heating component of an electric space heating customer's consumption currently averages about 10,000 kWh. Changes in real incomes, real electricity prices and real appliance prices should have little effect on future consumption levels since electric space heating customers already have very high saturations of all major household appliances. Thus, SUFG assumes that this component of a space heating customer's consumption will also remain constant during the forecast period (marginal efficiency improvements will offset marginal saturation and utilization increases). These are the same assumptions made for SUFG's first forecast in 1987. They have been reviewed each year as new data have become available.

Summary Of Results

The remainder of this chapter describes SUFG's current residential electricity sales projections. First, the current projection of residential sales growth is explained in terms of the model sensitivities and changes in the major explanatory variables. Next, the current base projection is compared to past base projections and then to the current high and low scenario projections. Also, at each step, significant differences in the projections are explained in terms of the model sensitivities and changes in the major explanatory variables.

Model Sensitivities

The major economic drivers in the residential econometric model include residential customers, household income, and electricity, natural gas and oil prices. The sensitivity of the residential electricity projection to changes in these variables was simulated one at a time by increasing each variable ten percent above the base scenario levels and observing the change in electricity use. The results are shown in Table 5-1.

Electricity consumption increases substantially due to increases in both the number of customers and household income. As expected, electricity rate increases reduce electric consumption. Changes in oil prices do not materially affect electricity consumption.

Table 5-1. Residential Model Long-Run Sensitivities

10 Percent Increase In:	Causes This Percent Change in Electric Use
Number of Customers	11.1
Electric Rates	-2.4
Natural Gas Price	1.0
Distillate Oil Prices	0.0
Appliance Prices	-1.8
Household Income	2.0

Indiana Residential Electricity Sales Projections

Actual sales, as well as past and current projections, are shown in Figure 5-3. The shaded numbers in the table and the heavy line in the graph are historical consumption. The growth rate for the current base projection of Indiana residential electricity sales is 1.95 percent, slightly lower than SUFG's 2001 projection. Table 5-2 shows the growth rates of the major residential drivers for the current scenarios and the SUFG 2001 base case. In all of the residential sector drivers, the current base exhibits somewhat higher growth resulting in a higher residential electricity use forecast. The growth rates for the fossil fuel (oil and natural gas) prices over the forecast horizon are very sensitive to the beginning year due to the recent volatility in prices. Long-term patterns for the entire forecast horizon are very similar for both the current and previous projections. Table 5-3 summarizes SUFG's base projections of residential electricity sales growth since 1996. These projections are broken down by the portion of the growth rate attributable to the growth in number of customers and growth in utilization per customer, before and after DSM. As the table shows, approximately one third of projected sales growth is attributable to customer growth and two thirds to changes in electric intensity (price and income effects). The net effect of changes in energy prices is to increase electric intensity about 0.2 percent per year. The small amount of residential DSM, primarily load shifting, has virtually no effect on residential electric intensity growth. The remaining growth in electric intensity is accounted for by income growth and declining real appliance prices.

As shown in Figure 5-4, the growth rates for the high and low residential scenarios are about 0.4 percent higher and 0.2 lower than the base scenario. This difference is due to differences in the growth of total customers and household income.

Indiana Residential Electricity Price Projections

Historical values and current projections of residential electricity prices are shown in Figure 5-5. In real terms residential electricity prices have been declining since the mid-1980s. SUFG projects this trend to continue until about 2005 when slower declines in utility steam coal prices coupled with the need for additional generation resources lead to relatively constant electricity prices. SUFG's real price projections for the individual IOUs all follow the same patterns as the state as a whole, but there are variations across the utilities.

Table 5-2. Residential Model Explanatory Variables -- Growth Rates by Forecast (%)

Forecast	Current Scenario (2002-2021)			2001 Forecast (2000-2019)
	Base	Low	High	Base
No. of Customers	0.66	0.66	0.69	0.71
Appliance Prices	-3.00	-3.00	-3.00	-3.00
Electric Rates	-0.38	-0.12	-0.52	-0.98
Natural Gas Price	0.26	0.26	0.26	-0.42
Oil Prices	0.43	0.43	0.43	-0.77
Household Income	1.69	1.24	2.81	1.91

Table 5-3. History of SUFG Residential Sector Growth Rates (%)

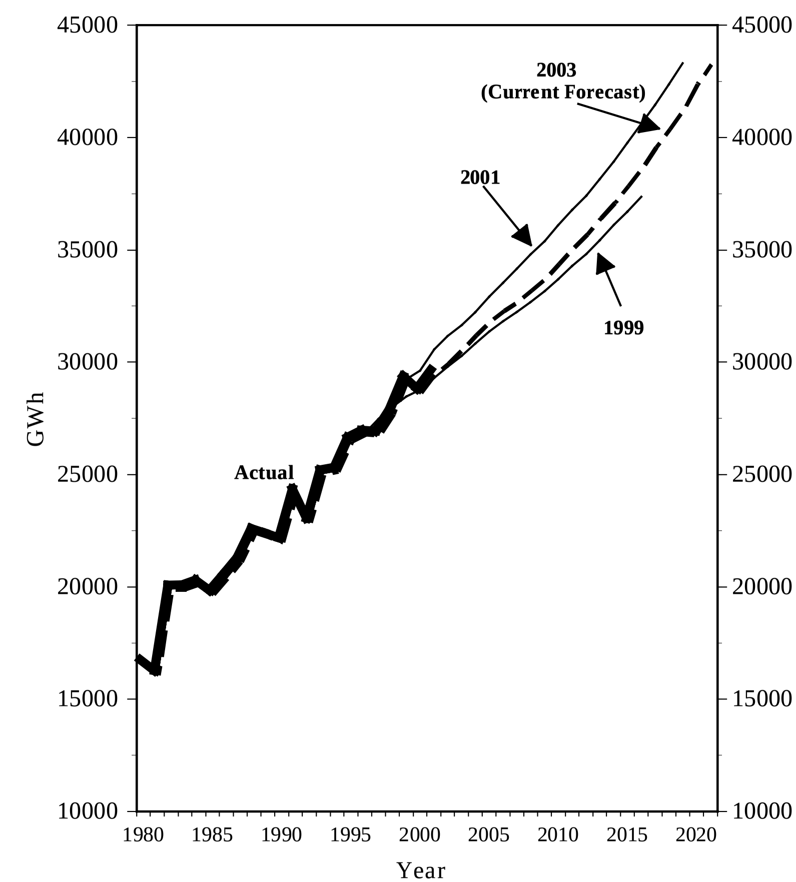
Forecast	No. of Customer	Prior to DSM		After DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2003 SUFG Base (2002-2021)	0.66	1.30	1.96	1.29	1.95
2001 SUFG Base (2000-2019)	0.71	1.31	2.02	1.31	2.02
1999 SUFG Base (1997-2016)	0.67	0.96	1.63	0.96	1.63

Figure 5-3. Indiana Residential Electricity Sales in GWh (Historical, Current and Previous Forecasts)

Year	Year of Forecast 1999	2001	2003
1990	22037	22037	22037
1991	24215	24215	24215
1992	22916	22916	22916
1993	25060	25060	25060
1994	25176	25176	25176
1995	26513	26513	26513
1996	26833	26833	26833
1997	27476	26792	26792
1998	28011	27745	27745
1999	28468	29238	29238
2000	28783	29625	28684
2001	29300	30569	29516
2002	29791	31161	29988
2003	30280	31651	30615
2004	30811	32213	31256
2005	31353	32918	31873
2006	31823	33525	32335
2007	32242	34159	32742
2008	32686	34797	33244
2009	33154	35396	33785
2010	33693	36090	34433
2011	34299	36778	35103
2012	34813	37420	35742
2013	35430	38158	36461
2014	36109	38939	37148
2015	36696	39766	37903
2016	37366	40625	38709
2017		41471	39612
2018		42382	40427
2019		43319	41285
2020			42444
2021			43317

Average Compound Growth Rates

Forecast Period	1997-16	2000-19	2002-21
	1.63	2.02	1.95



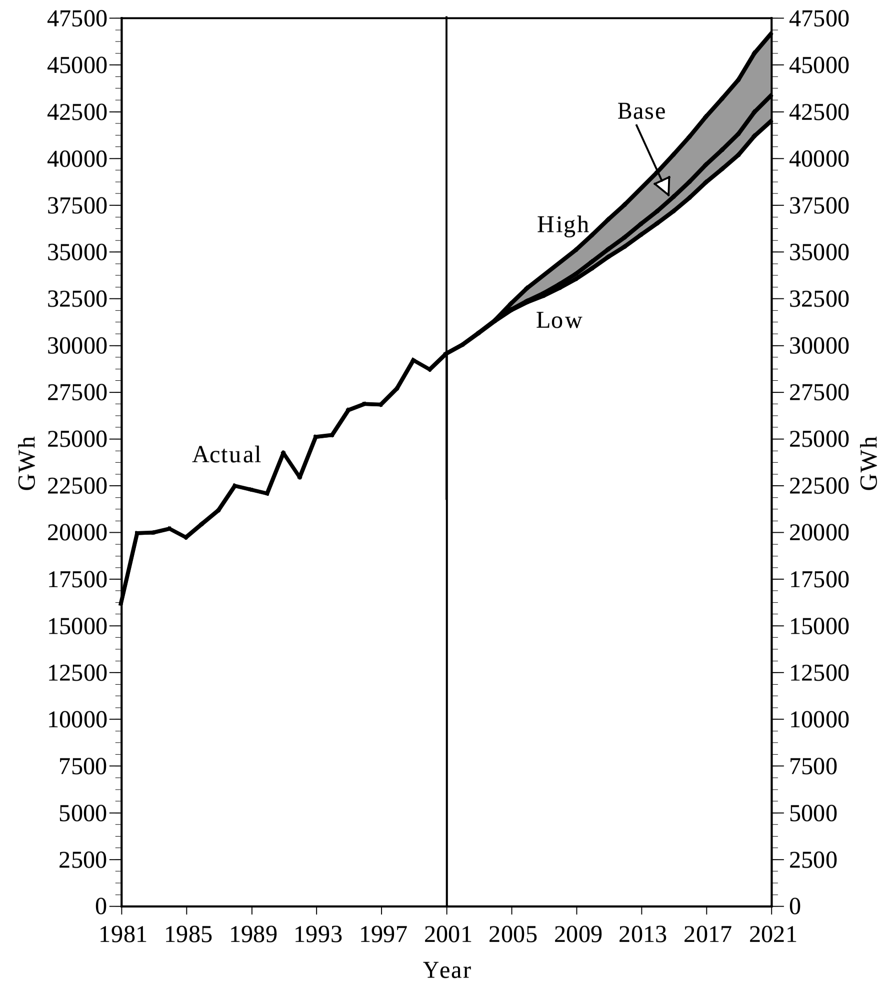
Notes: The shaded numbers in the table and the heavy line in the graph are historical requirements. (For an explanation on how SUFG arrives at these numbers, see Appendix A)

Figure 5-4. Indiana Residential Electricity Sales by Scenario in GWh

Year	Base	Low	High
1996	26833	26833	26833
1997	26792	26792	26792
1998	27663	27663	27663
1999	29180	29180	29180
2000	28684	28684	28684
2001	29516	29516	29516
2002	29988	29987	29997
2003	30615	30613	30634
2004	31256	31253	31287
2005	31873	31843	32205
2006	32335	32261	33021
2007	32742	32611	33704
2008	33244	33040	34395
2009	33785	33511	35071
2010	34433	34086	35865
2011	35103	34687	36688
2012	35742	35247	37479
2013	36461	35880	38360
2014	37148	36491	39227
2015	37903	37146	40159
2016	38709	37860	41121
2017	39612	38672	42180
2018	40427	39393	43163
2019	41285	40155	44176
2020	42444	41161	45589
2021	43317	41953	46605

Average Compound Growth Rates

Selected Periods	Base	Low	High
1980-85	3.48	3.48	3.48
1985-90	2.26	2.26	2.26
1990-95	3.77	3.77	3.77
1995-00	1.59	1.59	1.59
2000-05	2.13	2.11	2.34
2002-21	**1.95**	**1.78**	**2.35**



Notes: The shaded numbers in the table and the heavy line in the graph are historical values. (For an explanation on how SUFG arrives at these numbers, see Appendix A)

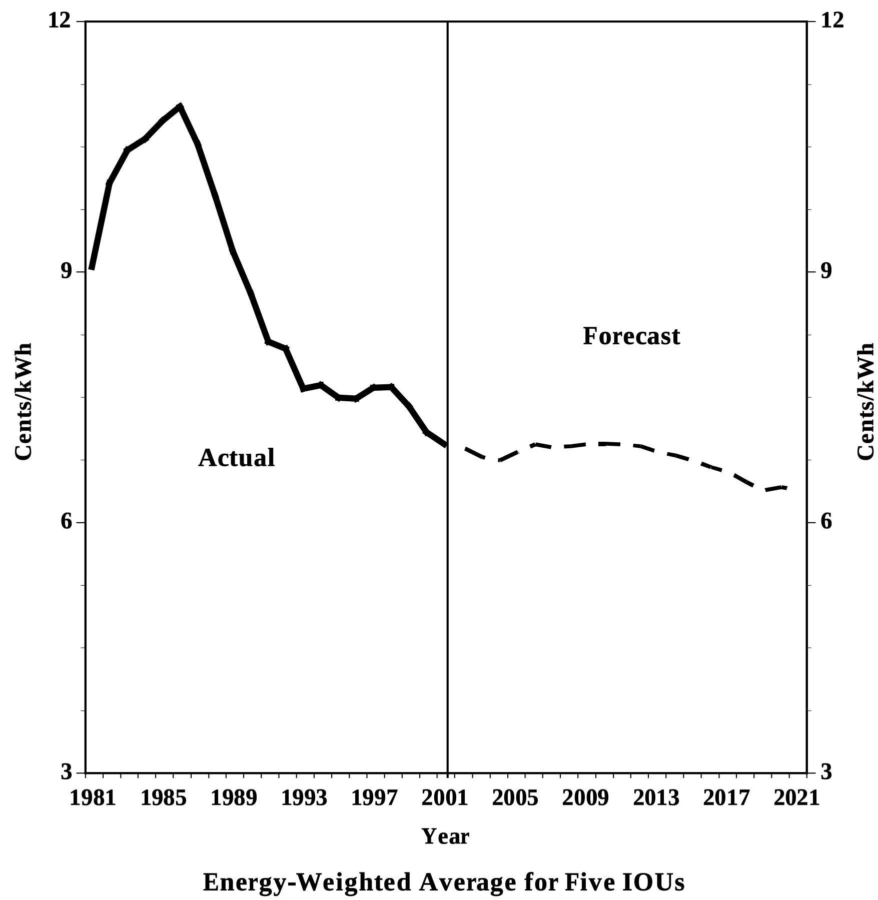
Figure 5-5. Indiana Residential Base Real Price Projections (in 2001 Dollars)

Year	Cents/ kWh
1980	8.87
1981	9.04
1982	10.04
1983	10.44
1984	10.57
1985	10.79
1986	10.96
1987	10.51
1988	9.89
1989	9.23
1990	8.72
1991	8.14
1992	8.06
1993	7.58
1994	7.62
1995	7.47
1996	7.46
1997	7.59
1998	7.60
1999	7.37
2000	7.06

Year	Cents/ kWh
2001	6.92
2002	6.90
2003	6.80
2004	6.76
2005	6.86
2006	6.95
2007	6.92
2008	6.93
2009	6.95
2010	6.96
2011	6.95
2012	6.93
2013	6.86
2014	6.82
2015	6.76
2016	6.68
2017	6.62
2018	6.50
2019	6.40
2020	6.44
2021	6.41

Average Compound Growth Rates

Selected Periods	(%)
1980-85	4.00
1985-90	-4.17
1990-95	--3.04
1995-00	--1.14
2000-05	-056
2002-21	**-0.38**



Energy-Weighted Average for Five IOUs

Notes: The shaded numbers in the table and the heavy line in the graph are historical values. (For an explanation on how SUFG arrives at these numbers, see Appendix A.)

COMMERCIAL ELECTRICITY SALES

Overview

SUFG has two distinct models of commercial electricity sales, econometric and end-use, that have specific strengths and complement each other. SUFG staff developed the econometric model and acquired a proprietary end-use model, Commercial Energy Demand Modeling System (CEDMS). CEDMS, like its residential counterpart, REEMS, is a descendant of the first generation of end-use models developed at ORNL during the late 1970s for the Department of Energy (DOE). CEDMS, however, bears little resemblance to its ORNL ancestor. Jerry Jackson and Associates actively supports CEDMS and it continues to define the state-of-the-art in commercial sector end-use forecasting models.

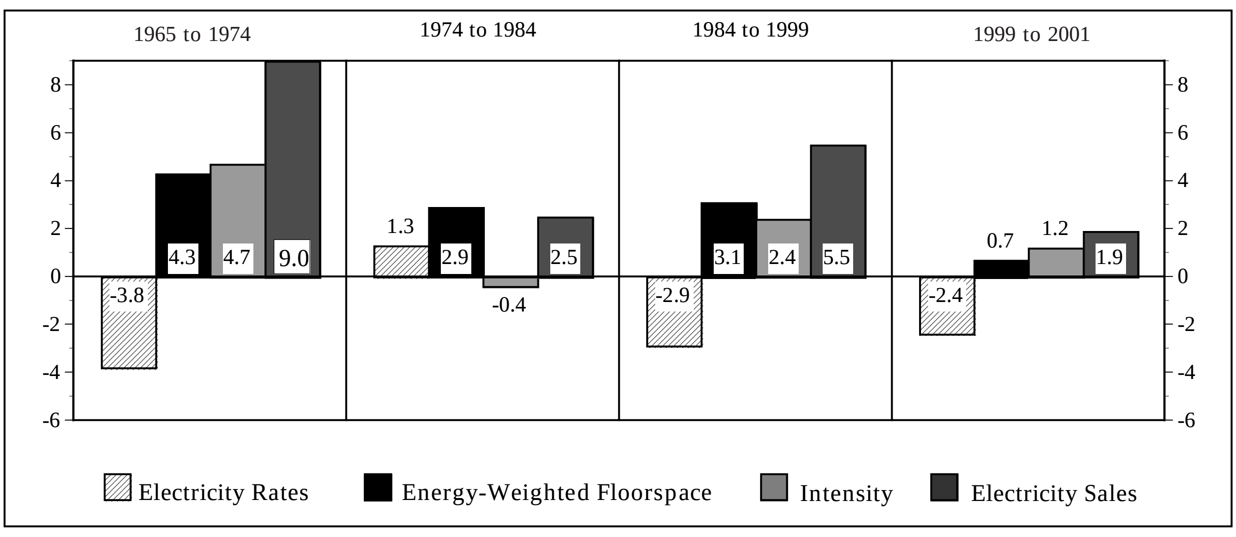
Prior to 1993, SUFG relied on its econometric model to project commercial electricity sales. SUFG used the end-use model for general comparison purposes and for its structural detail. (CEDMS estimates commercial floor space for building types and estimates energy use for end uses within each building type.) SUFG also took advantage of the building type detail in CEDMS to construct the major economic drivers for its econometric model. In 1993, SUFG made CEDMS its primary commercial sector forecasting model for several reasons. First, based on experience with the model over several years, SUFG is confident it provides realistic energy projections under a wide range of assumptions. Next, in contrast to the significant differences between the residential end-use and econometric model projections (discussed in Chapter 5), the differences between the commercial models are small since both the econometric model and CEDMS forecast similar changes in electric intensity.

Historical Perspective

Historical trends in commercial sector electricity sales have been distinctly different in each of the last four recent periods (see Figure 6-1).

Changes in electric intensity, expressed as changes per square foot of energy-weighted floor space, arise from changes in building and equipment efficiencies as well as changes in equipment utilization, end-use saturations and new end uses. Electric intensity increased rapidly during the era of cheap energy (4.7 percent per year) as seen in Figure 6-1 prior to the OPEC oil embargo. This trend was interrupted by the significant upward swing in electricity prices during 1974-84, which resulted in a decrease in energy intensity. As electricity prices fell again during the 1984-99 pe-

Figure 6-1. State Historical Trends in the Commercial Sector (Annual Percent Change)



riod, electric intensity rose but at a slower rate (2.4 percent) than that observed during the pre-embargo period. New commercial buildings and energy-using equipment continue to be more energy-efficient than the stock average but these efficiency improvements are offset by an increased demand for energy services.

Since 1999 the decrease in economic activity has retarded growth in commercial floorstock, intensity of electricity use, and electricity use despite continued declines in real electricity prices. Even though few years of data are available since 1999, the decrease in the growth in the commercial sector is unmistakeable.

Model Description

Figure 6-2 depicts the structure of the commercial end-use model. As the figure shows, CEDMS uses a disaggregated capital stock approach to forecast energy use. Energy use is viewed as a derived demand in which electricity and other fuels are inputs, along with energy-using equipment and building envelopes, in the production of end-use services.

The disaggregation of energy demand is as important in the modeling of the commercial sector as it is for modeling the residential sector. CEDMS divides commercial buildings among 10 building types. It also divides energy use in each building type among 14 possible end uses, including a residual use category. For end uses such as space heating, where non-electric fuels compete with electricity, CEDMS further disaggregates energy use among fuel types. (This disaggregation scheme is illustrated at the top of Figure 6-2.) CEDMS also divides buildings among vintages, i.e., the year the building was constructed, and simulates energy use for each vintage and building type.

CEDMS projects energy use for each building vintage according to the following equation:

$$Q\,(T, i, k, l, t) = U\,(i, k, l, t) * e\,(i, k, l, t) * a\,(i, k, l, t) * A\,(l, t) * d\,(l, T-t)$$

where

$*$ = multiplication operator;

T = forecast year;

Q = energy demand for fuel i, end use k, building type l and vintage t in the forecast year;

t = building vintage (year);

U = utilization, relative to some base year;

e = energy use index, kWh / sqft / year or Btu / sqft / year;

a = fraction of floor space served by fuel i, end use k, and building type l for floor space additions of vintage t;

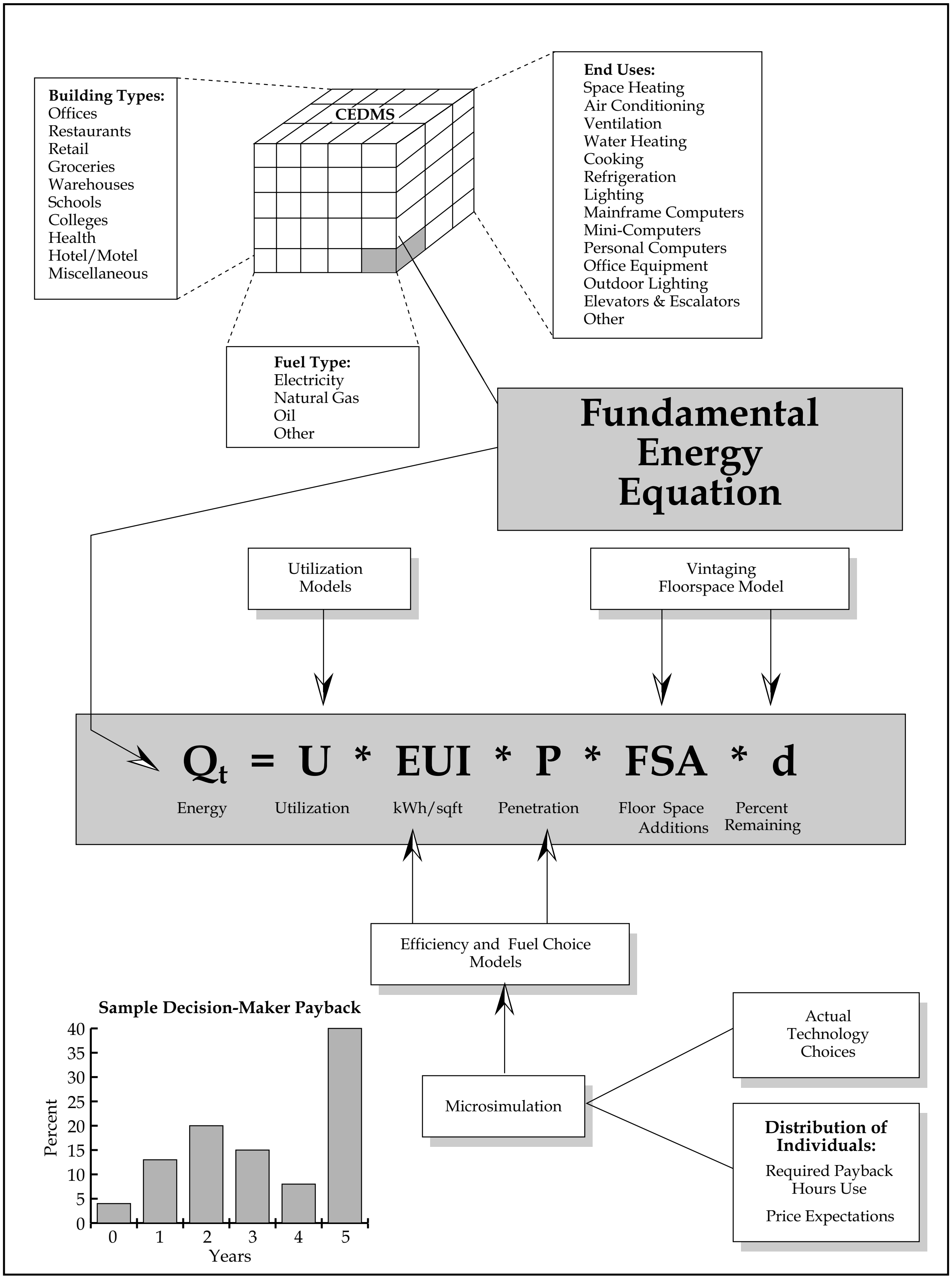
A = floor space additions by vintage t and building type l; and

d = fraction of floor space of vintage t still standing in forecast year T.

CEDMS' central features are its explicit representation of the joint nature of decisions regarding fuel choice, efficiency choice and the level of end-use service, as well as its explicit representation of costs and energy use characteristics of available end-use technologies in these decisions.

CEDMS jointly determines fuel and efficiency choices through a methodology known as discrete choice microsimulation. Essentially, sample firms in the model make choices from a set of discrete heating, ventilation and air conditioning (HVAC) equipment options. Each discrete equipment option is characterized by its fuel type, energy use and cost. The discrete choice representation incorporates many significant advantages over the technology curve representation used in the earlier ORNL model. CEDMS uses the discrete technology choice methodology to model equipment choices for HVAC, water heating, refrigeration and lighting. HVAC and lighting accounts for 80 percent of total electricity use by commercial firms.

Figure 6-2. Structure of Commercial End-Use Energy Modeling System



Equipment standards are easily incorporated in CEDMS' equipment choice submodels. For example, the Energy Policy Act of 1992 (EPACT) significantly affects the forecast for commercial lighting by prohibiting the manufacture of most 40 Watt and 75 Watt lamps (of these standard lamp sizes, only a few specialty lamps now meet both efficiency and color rendering requirements). EPACT's equipment standards for air conditioning and motors are also incorporated in CEDMS.

Besides efficiency and fuel choices, CEDMS also models changes in equipment utilization, or intensity of use. For equipment that has not been added or replaced in the previous year, changes in equipment utilization are modeled using fuel-specific, short-run price elasticities and changes in fuel prices. For new equipment installed in the current year, utilization depends on both equipment efficiency and fuel price. For example, a 10 percent improvement in efficiency and a 10 percent increase in fuel prices would have offsetting effects since the total cost of producing the end-use service is unchanged.

Summary Of Results

The remainder of this chapter describes SUFG's commercial electricity sales projections. First, the current base projection of commercial sales growth is explained in terms of the model sensitivities and changes in the major explanatory variables. Next, the current base projection is compared to past base projections and then to the current low and high scenario projections. At each step, significant differences in the projections are explained in terms of the model sensitivities and changes in the major explanatory variables.

Model Sensitivities

The major economic drivers to CEDMS include commercial floor space by building type (driven by non-manufacturing employment and population), electricity, natural gas and oil prices. The sensitivity of the electricity projection to changes in these variables was simulated one at a time by increasing each variable ten percent above the base scenario levels and observing the change in commercial electricity use. The results are shown in Table 6-1. An interesting result is that changes in commercial floor space lead to more than proportional changes in electricity use. The reason for this is that new buildings tend to have greater saturations of electric end uses, even though they are more efficient. The table also shows that changes in the price of competing forms of energy have little impact on electricity use.

Table 6-1. Commercial Model Long-Run Sensitivities

10 Percent Increase In:	Causes This Percent Change in Electric Use
Electric Rates	-2.5
Natural Gas Price	0.2
Distillate Oil Prices	0.0
Coal Prices	0.0
Electric Energy-Weighted Floor Space	12.0

Indiana Commercial Electricity Sales Projections

Historical data as well as past and current projections are illustrated in Figure 6-3. The shaded numbers in the table and the heavy line in the graph are historical consumption. As can be seen, the current base projection of Indiana commercial electricity sales growth is 2.71 percent. The growth rates for the major explanatory variables are shown in Table 6-2. Note that the change from 2001 for all of the drivers in Table 6-2 lead to increased commercial sector energy purchases. Table 6-3 summarizes SUFG's base projections of commercial electricity sales growth for the last three SUFG forecasts. Floor space growth accounts for about 2 percent growth annually. The net effect of changes in energy prices and the mix in types of floor space is to increase electricity use about 0.5 percent per year. The relatively small DSM programs have virtually no effect. Thus, about 80 percent of projected sales growth is attributable to floor space growth, with the remaining contribution from increased intensity.

As shown in Figure 6-3, the current projection is very similar to the 2001 forecast. The current projection starts out lower but grows at a slightly higher rate. The lower starting point is due to the recent downturn in the economy and the higher growth rate is due to similar, but higher growth in floorstock and electric intensity in the current forecast. Finally, Table 6-3 indicates that the impact of utility-sponsored DSM programs is not significant in the current forecast.

As shown in Figure 6-4, the growth rates for the low and high scenarios are about 1.1 percent lower and 1.0 percent higher than the base scenario, respectively. These differences are almost entirely due to a difference in floor space growth.

Indiana Commercial Electricity Price Projections

Historical values and current projections for commercial electricity prices are shown in Figure 6-5. In real terms, commercial electricity prices have been declining since the mid-1980s. SUFG projects this trend to continue until about 2004 when slower declines in utility steam coal prices coupled with the need for additional generation resources lead to relatively constant electricity prices through 2012. Real prices are projected to slowly fall through the last half of the forecast period. SUFG's real price projections for the individual IOUs all follow the same pattern in the state as a whole, but there are variations across the utilities.

Table 6-2. Commercial Model -- Growth Rates (%) for Selected Variables (2003 SUFG Scenarios and 2001 Base Forecast)

Forecast	Current Scenario (2002-2021)			2001 Forecast (2000-2019)
	Base	Low	High	Base
Electric Rates	-0.34	-0.09	-0.50	-0.73
Natural Gas Price	0.55	0.55	0.55	-0.11
Oil Prices	0.60	0.60	0.60	-0.75
Energy-Weighted Floor Space	2.15	1.12	2.99	2.11

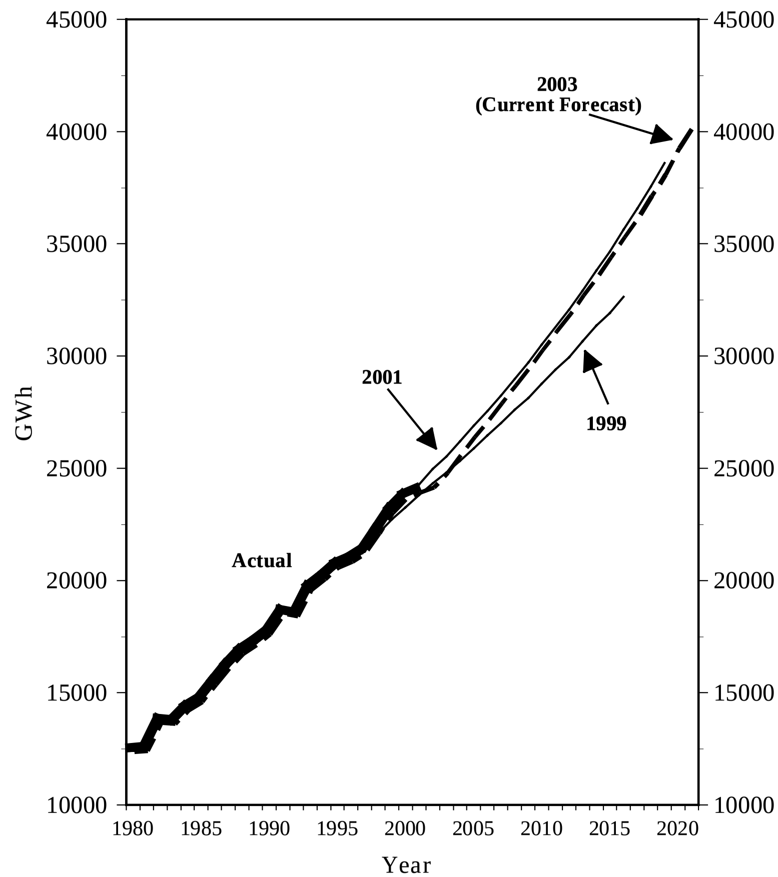
Table 6-3. History of SUFG Commercial Sector Growth Rates (%)

Forecast	Electric Energy-Weighted Floor Space	Prior to DSM		After DSM	
		Intensity	Sales Growth	Intensity	Sales Growth
2003 SUFG Base (2002-2021)	2.15	0.56	2.71	0.56	2.71
2001 SUFG Base (2000-2019)	2.11	0.46	2.57	0.46	2.57
1999 SUFG Base (1997-2016)	1.89	0.34	2.23	0.34	2.23

Figure 6-3. Indiana Commercial Electricity Sales in GWh (Historical, Current and Previous Forecasts)

	Year of Forecast		
Year	1999	2001	2003
1990	17659	17659	17659
1991	18580	18580	18580
1992	18456	18456	18456
1993	19627	19627	19627
1994	20116	20116	20116
1995	20646	20646	20646
1996	20909	20909	20909
1997	21468	21295	21295
1998	22101	22158	22158
1999	22738	23089	23089
2000	23271	23849	23721
2001	23795	24280	23975
2002	24333	24977	24206
2003	24815	25536	24855
2004	25319	26189	25663
2005	25883	26904	26451
2006	26471	27561	27195
2007	27014	28239	27960
2008	27609	28976	28751
2009	28139	29713	29524
2010	28759	30503	30327
2011	29392	31290	31145
2012	29959	32084	31923
2013	30671	32910	32765
2014	31357	33812	33582
2015	31917	34646	34462
2016	32636	35628	35355
2017		36584	36247
2018		37544	37184
2019		38609	38133
2020			39309
2021			40240

Average Compound Growth Rates			
Forecast Period	1997-16	2000-19	2002-21
	2.23	2.57	2.71



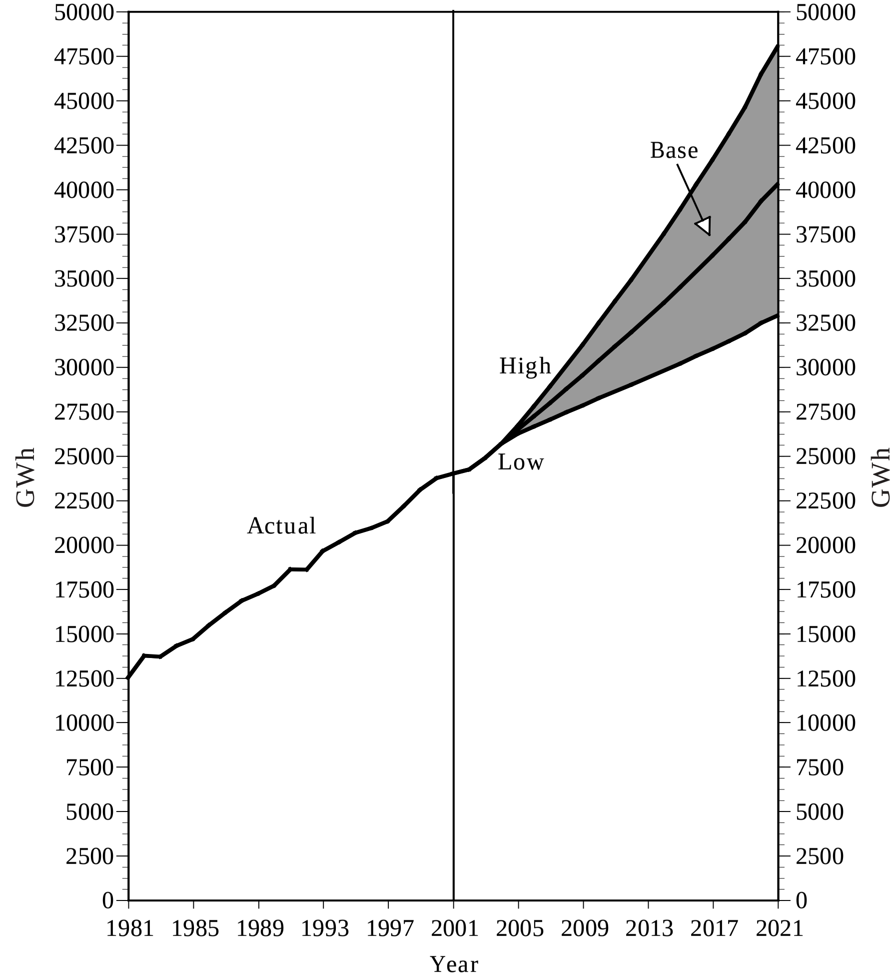
Notes: The shaded numbers in the table and the heavy line in the graph are historical requirements. (For an explanation on how SUFG arrives at these numbers, see Appendix A)

Figure 6-4. Indiana Commercial Electricity Sales by Scenario in GWh

Year	Base	Low	High
1996	20909	20909	20909
1997	21295	21295	21295
1998	22166	22166	22166
1999	23078	23078	23078
2000	23721	23721	23721
2001	23975	23975	23975
2002	24206	24206	24206
2003	24855	24855	24855
2004	25663	25663	25663
2005	26451	26228	26674
2006	27195	26618	27754
2007	27960	27017	28892
2008	28751	27431	30068
2009	29524	27817	31227
2010	30327	28219	32451
2011	31145	28610	33676
2012	31923	28977	34882
2013	32765	29382	36180
2014	33582	29769	37471
2015	34462	30172	38837
2016	35355	30592	40238
2017	36247	31003	41641
2018	37184	31433	43096
2019	38133	31874	44604
2020	39309	32456	46462
2021	40240	32863	47987

Average Compound Growth Rates

Selected Periods	Base	Low	High
1980-85	3.36	3.36	3.36
1985-90	3.81	3.81	3.81
1990-95	3.17	3.17	3.17
1995-00	2.82	2.82	2.82
2000-05	2.20	2.03	2.37
2002-21	**2.71**	**1.62**	**3.67**



Notes: The shaded numbers in the table are historical values. (For an explanation on how SUFG arrives at these numbers, see Appendix A)

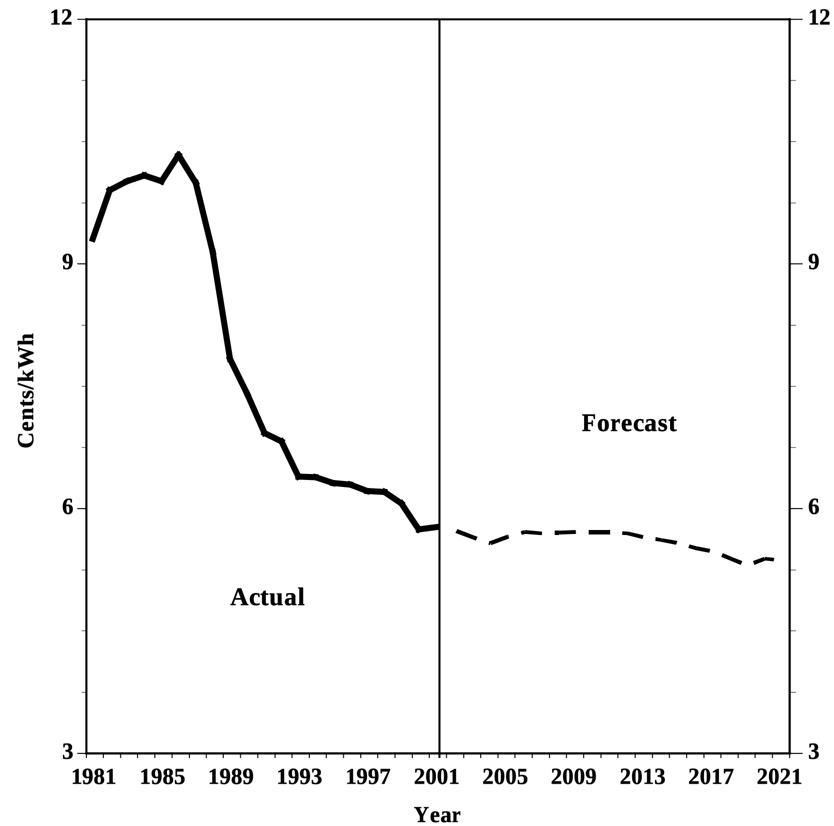
Figure 6-5. Indiana Commercial Base Real Price Projections (in 2001 Dollars)

Year	Cents/ kWh
1980	9.40
1981	9.28
1982	9.88
1983	9.99
1984	10.06
1985	9.99
1986	10.31
1987	9.97
1988	9.12
1989	7.81
1990	7.38
1991	6.90
1992	6.80
1993	6.37
1994	6.36
1995	6.29
1996	6.27
1997	6.19
1998	6.18
1999	6.04
2000	5.72

Year	Cents/ kWh
2001	5.75
2002	5.74
2003	5.66
2004	5.59
2005	5.67
2006	5.73
2007	5.71
2008	5.72
2009	5.73
2010	5.73
2011	5.73
2012	5.71
2013	5.66
2014	5.63
2015	5.59
2016	5.53
2017	5.49
2018	5.40
2019	5.32
2020	5.40
2021	5.38

Average Compound Growth Rates

Selected Periods	(%)
1980-85	1.23
1985-90	-5.88
1990-95	-3.14
1995-00	-1.90
2000-05	-0.17
2002-21	**-0.34**



Energy-Weighted Average for Five IOUs

Notes: The shaded numbers in the table and the heavy line in the graph are historical numbers. For an explanation on how SUFG arrives at these numbers, see Appendix A)

CHAPTER 7
INDUSTRIAL ELECTRICITY SALES

Overview

SUFG currently uses several models to analyze and forecast electricity use in the industrial sector. The primary forecasting model is INDEED, an econometric model developed by the Electric Power Research Institute (EPRI), which is used to model the electricity use of 16 major industry groupings in the state. Additionally, SUFG has used in various forecasts a highly detailed process model of the iron and steel industry, scenario-based models of the aluminum and foundries components of the primary metals industry, and an industrial motor drive model to evaluate and forecast the effect of motor technologies and standards.

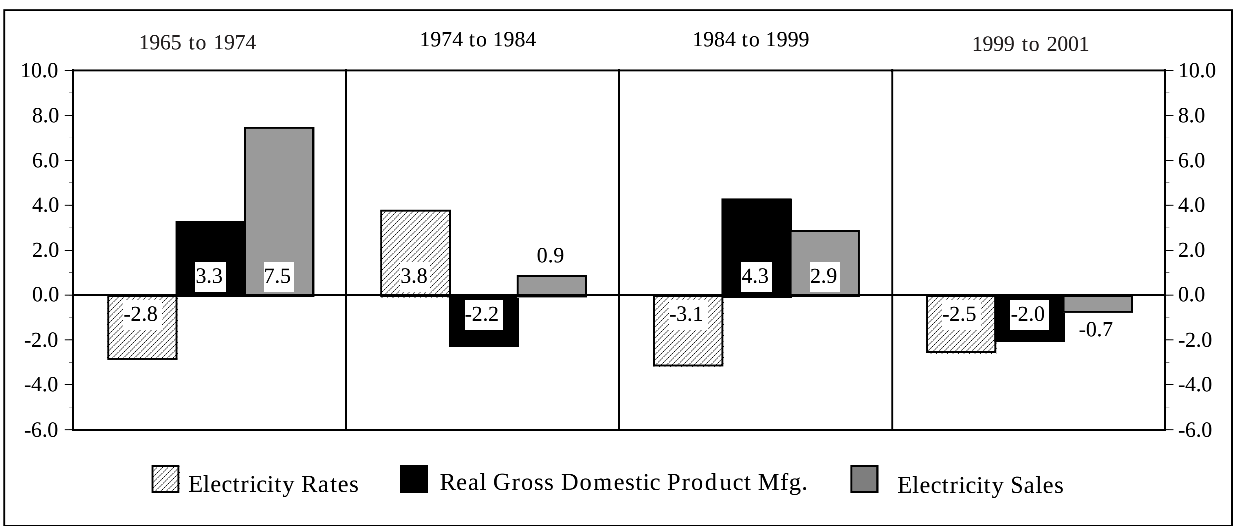
The econometric model is calibrated at the statewide level from data on cost shares obtained from the U.S. Department of Commerce Annual Survey of Manufacturers. SUFG has been using INDEED since 1992 to project individual industrial electricity sales for the 16 industries within each of the five IOUs. There are many econometric formulations that can be used to forecast industrial electricity use, which range from single equation factor demand models and fuel share models to "KLEM" models (KLEM denotes capital, labor, energy and materials). INDEED is a KLEM model. A KLEM model is based on the assumption that firms act as though they were minimizing costs to produce given levels of output. Thus, a KLEM model projects the changes in the quantity of each input, which result from changes in input prices and levels of output under the cost minimization assumption. For each of the 16 industry groups, INDEED projects the quantity consumed of eight inputs: capital, labor, electricity, natural gas, distillate and residual oil, coal and materials.

Historical Perspective

SUFG distinguishes four recent periods of distinctly different economic activity and growth — the decade prior to the oil embargo of 1974, 1974-1984, the more recent period, 1984-1999, and the current period, 1999 to the present. Figure 7-1 shows state growth rates for real manufacturing product, real electric rates and electric energy sales for the three periods.

During the decade prior to the OPEC oil embargo, industrial electricity sales increased 7.5 percent annually. In Indiana as elsewhere, sales growth was driven by the combined economic stimuli of falling electricity prices (2.8 percent per year in real terms) and growing

Figure 7-1. State Historical Trends in the Industrial Sector (Annual Percent Change)



manufacturing output (3.3 percent per year). During the decade following 1974, sales growth slowed as real electricity prices increased at an average rate of 3.8 percent per year and the state's manufacturing output declined at a rate of 2.2 percent per year. This turnaround in economic conditions and electricity prices resulted in a dramatic decline in the growth of industrial electricity sales from 7.5 percent per year prior to 1974 to 0.9 percent per year in the decade that followed. The fact that electricity sales increased at all is most likely attributable to increases in fossil fuel prices that occurred during the "energy crisis" of 1974-84. The recent period, 1984-1999, has witnessed another dramatic turnaround. The growth rate of industrial output once again becomes positive, and is substantially above the rate observed prior to 1974. Real electricity prices in Indiana continued to decline in the industrial sector. These conditions caused electricity sales growth to average 2.9 percent per year during the last 15 years.

The effect of the current economic slowdown is particularly pronounced in the industrial sector. Since 1999, real industrial electricity prices have continued to decline, but this decline has been more than offset by a decrease in manufacturing output, which in turn has lead to a decrease in industrial electricity use. In the residential (Chapter 5) and commercial (Chapter 6) sectors, decreased economic activity since 1999 has resulted in slower but positive growth in electricity use; in contrast, manufacturing electricity use has actually declined. The CEMR economic activity projections used in this electricity forecast do not suggest a turnaround in manufacturing until 2005-2006, so electricity use in the sector is forecast to be relatively flat for the first few years of the forecast horizon.

Model Description

Figure 7-2 depicts the relationship between the models used by SUFG to characterize electricity use in the industrial sector. Electricity used in the sector can be broken down in three ways -- Level I, by industry; Level II, by process step; and Level III, by energy end use. Each corresponds to a dimension of the cube in Figure 7-2. Currently, electricity use is subdivided into the 16 manufacturing industries listed in Table 7-1. At this time, only the iron and steel, foundries and aluminum portions of SIC 33 are broken down to Level II models. In addition, a model of electricity use by motors in industry projects the impact of motor technologies and standards geared toward particular end uses.

The Econometric Model

SUFG's primary forecasting model, INDEED, consists of a set of econometric models for each of Indiana's major industries listed in Table 7-1.

Each model is driven by projections of selected industrial GSP over the forecast horizon provided by CEMR. Each industry's share of GSP is given in the first column of Table 7-1. Over 75 percent of GSP is accounted for by the following industries: fabricated metals, 7 percent; electric machinery, 8 percent, primary metals, 10 percent; non-electric machinery, 12 percent; chemicals, 16 percent; and transportation, 23 percent.

The share of total electricity consumed by each industry is shown in column two. Both the chemical and primary metals industries are very electric intensive industries. Combined, they account for more than 45 percent of total industrial state electricity use.

Column three gives the current base output projections for the major industries obtained from the most recent CEMR forecast. As explained in Chapter 4, CEMR projections are developed using econometric models of the U.S. and Indiana economies. Manufacturing sector GSP projections are obtained by multiplying projected sector employment projections by a projection of GSP per employee, a measure of labor productivity.

In preparing this forecast, SUFG used the CEMR projections of GSP for SIC code 33, a large, intensive user of electricity composed largely of steel produc-

Figure 7-2. Structure of Industrial Energy Modeling System

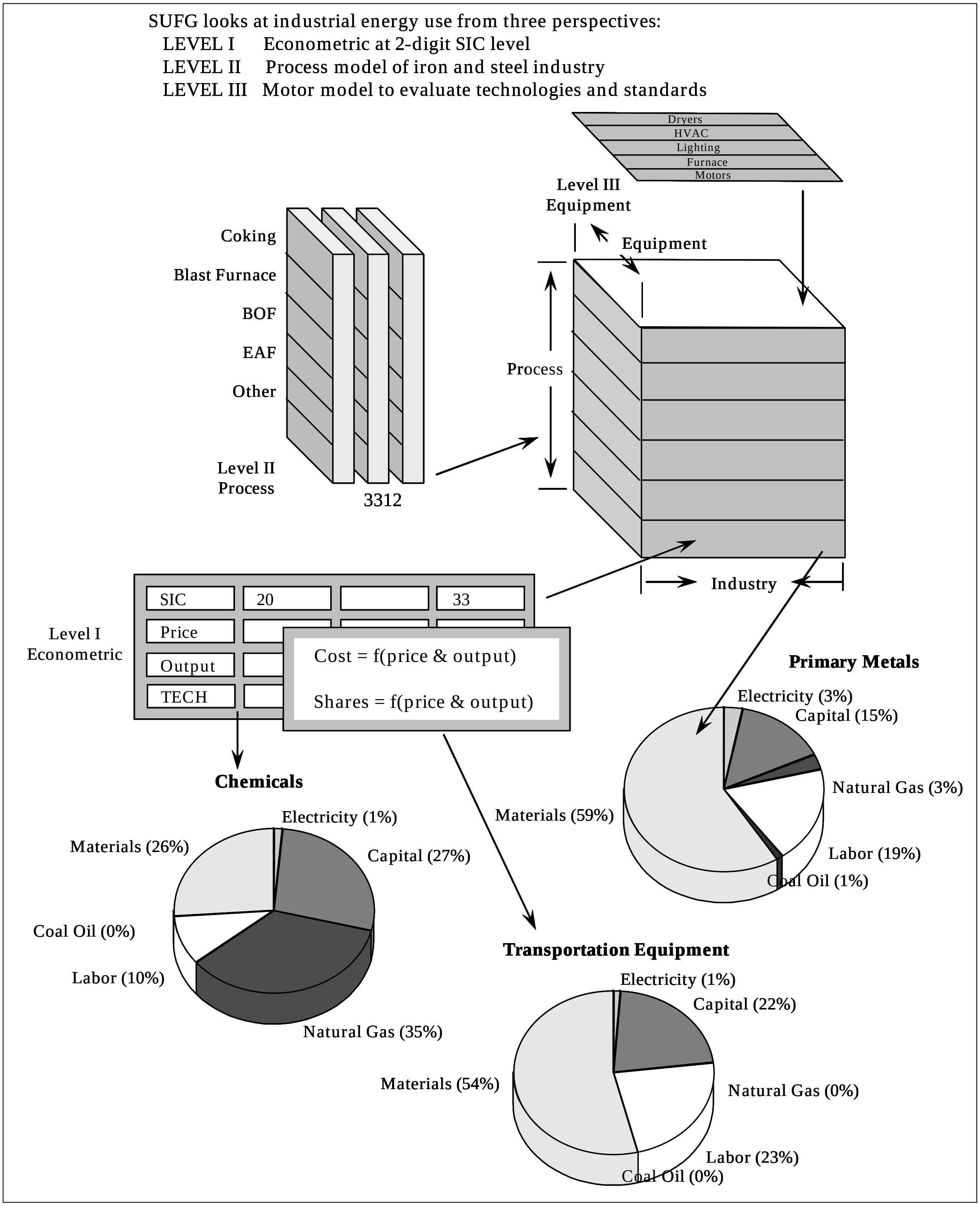


Table 7-1. Selected Statistics for Indiana's Industrial Sector (Prior to DSM) (%)

SIC	Name	Current Share of GSP	Current Share of Electricity Use	Forecast Growth in GSP Originating by Sector	Forecast Growth in Electricity Intensity by Sector	Forecast Growth in Electricity Use by Sector
20	Food & Kindred Products	4.15	5.82	-1.02	0.67	-0.35
24	Lumber & Wood Products	2.35	0.69	-0.10	-0.39	-0.49
25	Furniture & Fixtures	2.05	0.48	1.65	0.33	1.98
26	Paper & Allied Products	1.48	2.48	-1.06	0.25	-0.82
27	Printing & Publishing	2.66	1.02	-1.00	0.93	-0.07
28	Chemicals & Allied Products	15.89	17.40	1.50	1.18	2.67
30	Rubber & Misc. Plastic Products	4.64	5.92	3.43	0.36	3.78
32	Stone, Clay, & Glass Products	1.98	5.19	0.85	0.27	1.11
33	Primary Metal Products	9.72	28.45	0.34	1.89	2.23
34	Fabricated Metal Products	7.24	5.14	1.14	0.61	1.76
35	Industrial Machinery & Equipment	12.43	4.92	2.14	0.61	2.74
36	Electronic & Electric Equipment	7.88	5.16	2.53	0.40	2.93
37	Transportation Equipment	22.65	9.87	1.25	0.43	1.69
38	Instruments And Related Products	2.33	1.36	-1.15	0.16	-0.99
39	Miscellaneous Manufacturing	2.03	2.90	5.26	-4.53	0.72
	Total Manufacturing	**100.00**	**100.00**	**1.50**	**0.48**	**1.97**

tion, as the driver in the NIPSCO service area model and used aggregate manufacturing in all other service areas. The logic behind this is that the downturn in steel production has had a larger effect on the integrated mills than the mini-mills and the integrated mills are concentrated in the NIPSCO service area in northwest Indiana.

In another large intensive electricity using industry, chemicals (SIC 28), SUFG used the CEMR average GSP for all industries rather than industry-specific GSP projections. The rationale for this substitution is twofold. First, a portion of the chemicals industry, air separation is closely linked to integrated mill steel production due to the intensive use of oxygen by the integrated mills. Second, even though the chemicals industry has experienced rapid growth over the past several years, SUFG chose to use a more conservative estimate of future growth in this electric intensive industry by replacing the CEMR above average growth projection with a more modest projection.

Each industrial sector econometric model converts output by forecasting the total cost of producing the given output and the cost shares for each major input, i.e., capital, labor, electricity, gas, oil, coal and materials. The quantity of electricity is determined given the expenditure of electricity for each industry and its price.

As described earlier in this chapter, INDEED captures the competition between the various inputs for their share of the cost of production by assuming firms seek the mix of inputs that minimize the cost of the given level of output. Unit costs of gas, oil, coal, capital, labor and materials are inputs to the SUFG system, while the cost per kWh of electricity is determined by the SUFG modeling system The current SUFG forecast assumes that real natural gas prices in the industrial sector "spike" in 2001 then decline at about 5.6 percent per year until the year 2005 and increase at a rate of about 0.8 percent per year thereafter. Distillate fuel prices are assumed to follow a similar pattern, but are assumed to grow at a faster rate (0.85 percent per year) than gas after the year 2005. Unit costs for capital, labor and materials are consistent with the assumptions contained in the CEMR forecast of Indiana output growth.

The changes in electricity intensities, expressed as a percent change in kWh / dollar of GSP, are shown in column four of Table 7-1. While some intensities are expected to increase and some to decrease, industry-wide electricity intensity is expected to remain nearly constant over the forecast horizon.

The last column of Table 7-1 contains the projected annual percent increase in electricity sales by major industry. This projected increase is the sum of changes in GSP and kWh / GSP for each industry. Average industry electricity use across all sectors in the base scenario is expected to increase at an average of 1.97 percent per year over the forecast horizon.

Summary of Results

Model Sensitivities

Table 7-2 shows the impact of a 10 percent increase in each of the model inputs on all industry electricity consumption in the econometric model. Electricity sales are most sensitive to changes in output and electric rates, somewhat sensitive to changes in gas and oil prices, and insensitive to changes in assumed coal prices. Other major variables affecting industrial electricity use include the prices of materials, capital and labor. The model's sensitivities were determined by increasing each variable ten percent above the base scenario levels and observing the change in forecast industrial electricity use after 10 years.

Industrial Energy Projections: Current and Past

Past and current projections for industrial energy sales as well as overall annual average growth rates

Table 7-2. Industrial Model Long-Run Sensitivities

10 Percent Increase In:	Causes This Percent Change in Electric Use
Real Manufacturing Product	10.0
Electric Rates	-4.8
Natural Gas Price	1.4
Oil Prices	0.9
Coal Prices	0.2

for the current and past forecasts are shown in Figure 7-3 in both tabular and graphic form. The shaded numbers in the table and the heavy line in the graph are historical sales.

The impact of industrial sector DSM programs on growth rates for the 1999 and 2001 and current forecasts are contained in Table 7-3. The table also disaggregates the impact on energy growth of output, changes in the mix of output and electricity intensity. As in the residential and commercial sectors, DSM programs have virtually no impact on industrial sector electricity purchases. Current incremental DSM measures focus on peak shaving and load shifting rather than conservation. The affect of conservation activities during the 1990s are embedded in the historical data and SUFG's projections.

The current forecast projects that industrial sector electricity sales will grow from its present level of approximately 39,000 GWh to over 55,000 GWh by 2021. This growth rate of 1.97 percent per year is substantially lower than the 2.71 percent rate projected for the commercial and nearly identical to the 1.95 percent rate projected for the residential sector. As shown in Figure 7-3, the current forecast lies below the 2001 and 1999 forecasts until the end of the forecast horizon.

The lower forecast of industrial sector electricity energy purchases in the early years can be attributed to reduced economic activity. Industrial electric energy purchases are flat at the beginning of the forecast period with projections for 2003 about the same as historical purchases observed in 1999. The sales projections increase modestly throughout the remainder of the forecast as economic activity increases and the current projection of purchases is roughly the same as SUFG's 2001 and 1999 projections by 2015.

Industrial Energy Projections: SUFG Scenarios

Figure 7-4 shows how industrial requirements differ by scenario. Industrial sales, in the high scenario, are expected to increase to over 60,000 GWh by 2019, more than 14 percent higher than the base projection. In the low scenario, industrial sales grow slowly, which results in only 45,000 GWh sales by 2019, more than 14 percent below the base scenario.

The wide range of forecast sales is caused primarily by the equally wide range of the trajectories of industrial output contained in the CEMR low and high scenarios for the state. In the base scenario, CEMR expects GSP in the industrial sector to grow 1.50 percent per year during the forecast horizon. That rate is expected to be 2.56 percent in the high scenario and only 0.16 percent in the low scenario. This reflects the uncertainty regarding Indiana's industrial future contained in these forecasts. The high and low scenarios reflect an optimistic and pessimistic view regarding the ability of Indiana's industries to compete with other producers.

Indiana Industrial Electricity Price Projections

Historical values and current projections of industrial electricity prices are shown in Figure 7-5. In real terms, industrial electricity prices have been declining since the mid-1980s. SUFG projects this trend to continue until 2005 when slower declines in utility steam coal prices coupled with the need for additional generation resources lead to relatively constant real electricity prices. SUFG's real price projections for the individual IOUs all follow the same patterns as the state as a whole, but there are variations across the utilities.

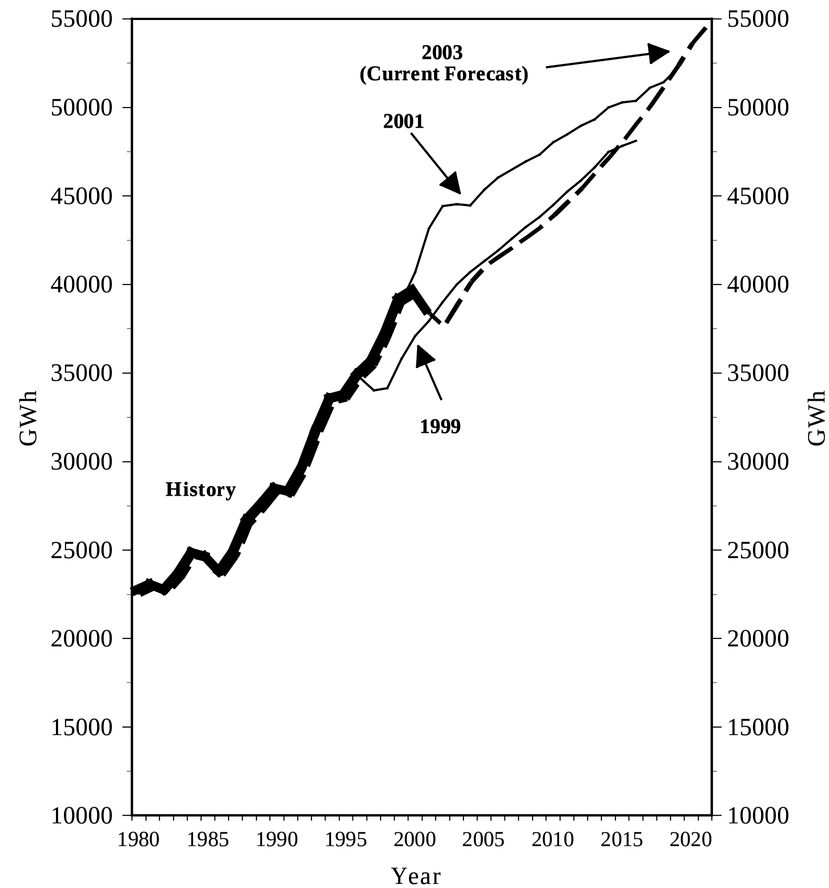
Table 7-3. History of SUFG Industrial Sector Growth Rates (%)

Forecast	Output	Mix Effects	Electric Energy-Weighted Output	Prior to DSM		After DSM	
				Intensity	Sales Growth	Intensity	Sales Growth
2003 SUFG Base (2002-2021)	1.50	-0.23	1.27	0.70	1.97	0.70	1.97
2001 SUFG Base (2000-2019)	1.41	-0.55	0.86	0.46	1.32	0.46	1.32
1999 SUFG Base (1997-2016)	1.58	-0.18	1.40	0.32	1.73	0.32	1.73

Figure 7-3. Indiana Industrial Electricity Sales in GWh (Historical, Current and Previous Forecasts)

	Year of Forecast		
Year	1999	2001	2003
1990	28311	28311	28311
1991	28141	28141	28141
1992	29540	29540	29540
1993	31562	31562	31562
1994	33395	33395	33395
1995	33590	33590	33590
1996	34755	34755	34755
1997	34031	35499	35499
1998	34148	37052	37052
1999	35776	39020	39020
2000	37079	40680	39513
2001	37940	43156	38398
2002	38998	44425	37697
2003	40004	44550	38973
2004	40703	44461	40224
2005	41332	45344	41101
2006	41914	46045	41650
2007	42587	46486	42166
2008	43241	46948	42736
2009	43827	47345	43304
2010	44490	48014	43994
2011	45248	48467	44751
2012	45864	48969	45512
2013	46620	49324	46386
2014	47479	49994	47272
2015	47824	50291	48207
2016	48127	50383	49196
2017		51111	50200
2018		51430	51296
2019		52197	52471
2020			53713
2021			54623

Average Compound Growth Rates			
Forecast Period	1997-16	2000-19	2002-21
	1.84	1.32	1.97



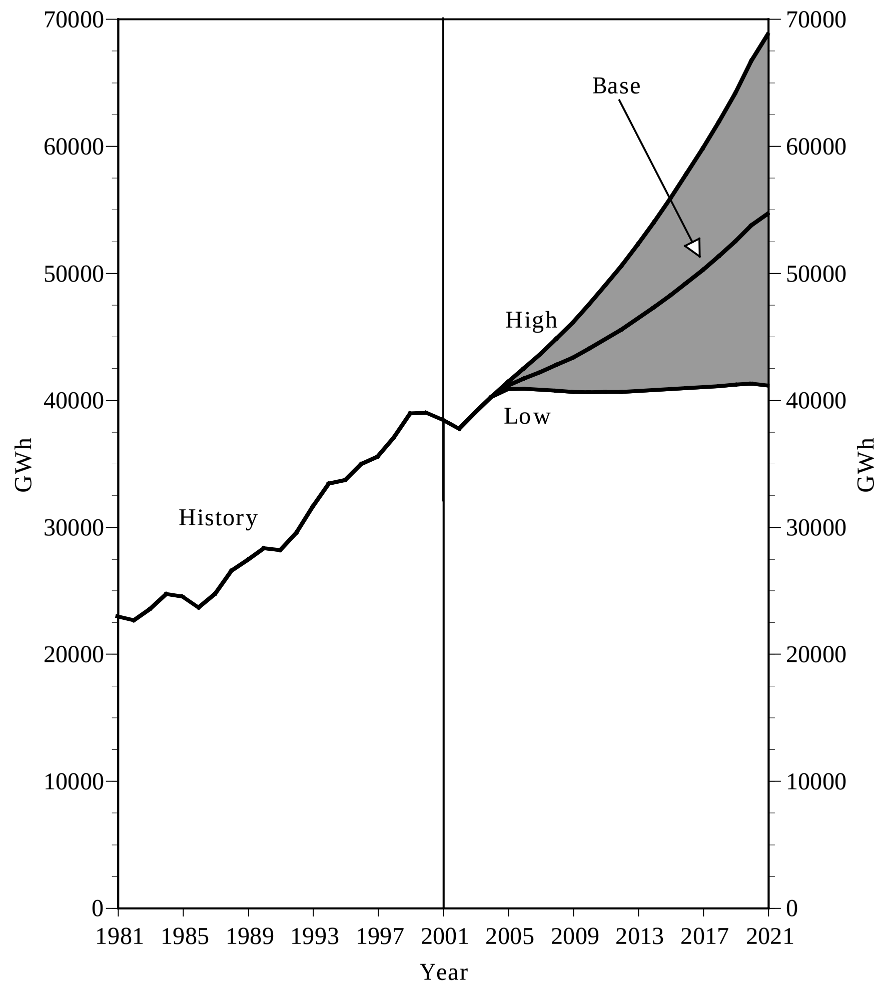
Notes: The shaded numbers in the table are historical values. (For an explanation on how SUFG arrives at these numbers, see Appendix A.)

Figure 7-4. Indiana Industrial Electricity Sales by Scenario in GWh

Year	Base	Low	High
1996	34920	34920	34920
1997	35499	35499	35499
1998	37012	37012	37012
1999	38916	38916	38916
2000	38969	38969	38969
2001	38398	38398	38398
2002	37697	37697	37697
2003	38973	38973	38972
2004	40224	40224	40224
2005	41101	40816	41383
2006	41650	40850	42449
2007	42166	40774	43581
2008	42736	40710	44808
2009	43303	40605	46067
2010	43994	40581	47476
2011	44751	40598	48980
2012	45512	40593	50514
2013	46386	40672	52210
2014	47272	40745	53972
2015	48207	40817	55833
2016	49196	40909	57773
2017	50200	40968	59760
2018	51296	41061	61892
2019	52471	41170	64130
2020	53713	41247	66676
2021	54623	41099	68751

Average Compound Growth Rates

Selected Periods	Base	Low	High
1980-85	1.66	1.66	1.66
1985-90	2.95	2.95	2.95
1990-95	3.52	3.52	3.52
1995-00	2.97	2.97	2.97
2000-05	1.07	0.93	1.21
2002-21	**1.97**	**0.46**	**3.21**



Notes: The shaded numbers in the table are historical values. (For an explanation on how SUFG arrives at these numbers, see Appendix A.)

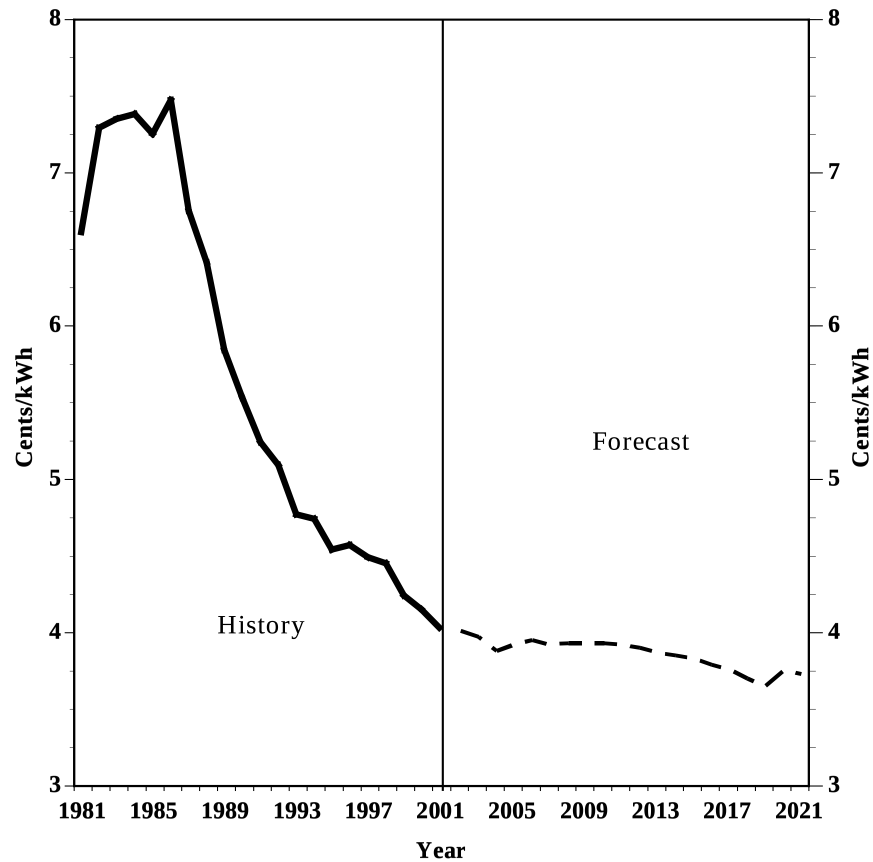
Figure 7-5. Indiana Industrial Base Real Price Projections (in 2001 Dollars)

Year	Cents/ kWh
1980	6.52
1981	6.60
1982	7.28
1983	7.34
1984	7.37
1985	7.24
1986	7.46
1987	6.74
1988	6.40
1989	5.83
1990	5.52
1991	5.23
1992	5.08
1993	4.76
1994	4.73
1995	4.53
1996	4.56
1997	4.48
1998	4.44
1999	4.23
2000	4.14

Year	Cents/ kWh
2001	4.02
2002	4.02
2003	3.98
2004	3.89
2005	3.93
2006	3.96
2007	3.93
2008	3.94
2009	3.94
2010	3.94
2011	3.93
2012	3.91
2013	3.88
2014	3.86
2015	3.84
2016	3.80
2017	3.77
2018	3.71
2019	3.66
2020	3.76
2021	3.74

Average Compound Growth Rates

Selected Periods	(%)
1980-85	2.11
1985-90	-5.29
1990-95	-3.84
1995-00	-1.78
2000-05	-1.08
2002-21	**-0.38**



Energy-Weighted Average for Five IOUs

Notes: The shaded numbers in the table are historical values. (For an explanation on how SUFG arrives at these numbers, see Appendix A.)

The Impact of the Economic Slowdown on Indiana Energy and Peak Demand

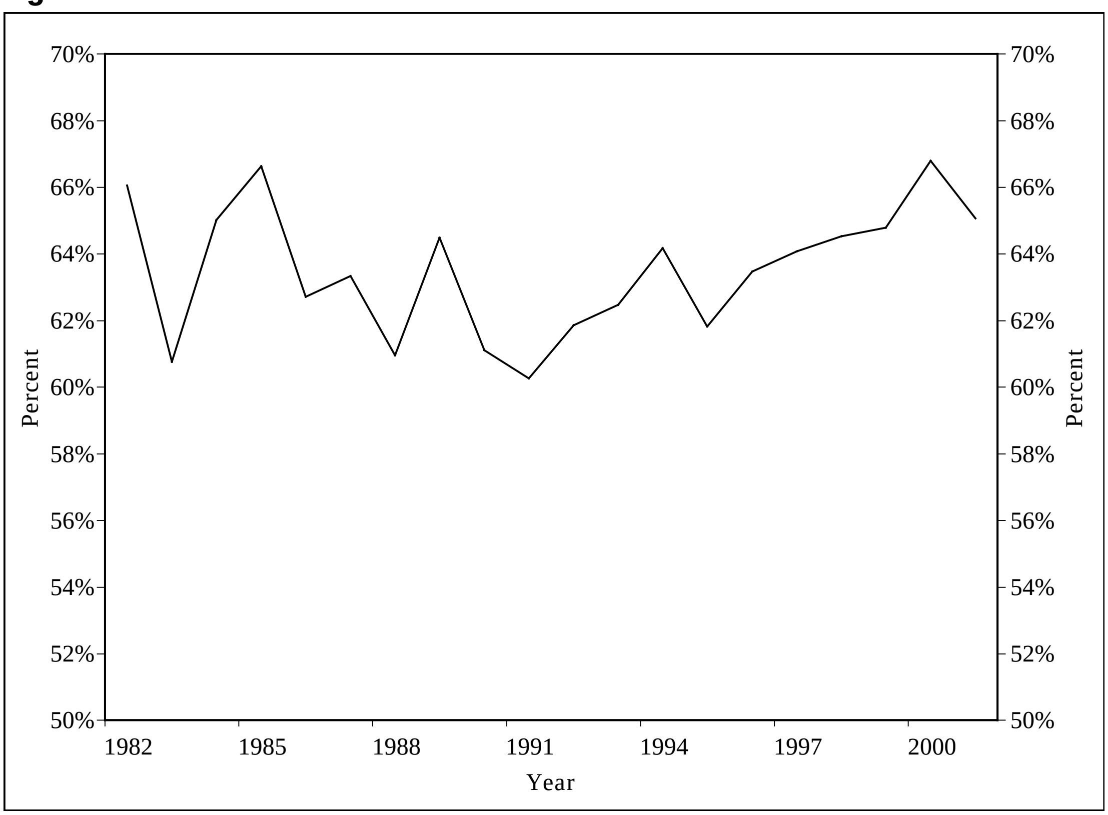
During the summer of 2002, many Indiana utilities set new records for the highest peak demand in company history. This is noteworthy for two reasons: overall annual electricity usage was not growing due to the slowing of the economy and the summer of 2002 was not unusually hot. This section examines why peak demand appears to be increasing while electricity requirements do not. This issue is of particular importance because new capacity needs are driven by peak demand.

A logical starting point for a comparison of peak demand to electricity requirements is to look at how the state's load factor has changed. Figure 8-1 shows the statewide load factor, which is the ratio of average hourly demand to peak hour demand, for each year from 1982 through 2001. The large variations from year to year result primarily from weather differences, but it is instructive that the lowest load factors occur in the slow economic periods of the early 1980s and 1990s. Load factors decline when peak demand increases faster than annual electricity consumption.

While it is possible to estimate what the peak demand would have been under normal weather, it is not particularly useful for these purposes since annual electricity consumption is also weather sensitive. Additionally, the effect of interruptible loads and the voluntary customer load reductions that occurred in 1998 and 1999 alter the peak demand numbers.

Since an examination of historical load factors does not provide a sufficient explanation for the observed phenomenon, the relationships between year to year changes in annual electricity consumption for each of the three main customer sectors (residential, commer-

Figure 8-1. Historical Statewide Load Factor



cial and industrial) to changes in statewide peak demand are provided in Figures 8-2, 8-3 and 8-4. These figures are scatter diagrams where each point represents the change from one year to the next in both peak demand on the horizontal axis and the sector's annual electricity consumption on the vertical axis. In Figure 8-2, it appears that as the change in residential electricity consumption becomes larger, the change in peak demand also grows. In Figure 8-3, changes in commercial electricity consumption are very consistent from year to year and appear to have less impact on peak demand. Finally, in Figure 8-4, there appears to be no relationship between changes in industrial electricity consumption and those in peak demand.

Residential electricity consumption has a major impact on peak demand due to the weather sensitivity of individual loads, particularly air conditioning. The historical relationship between the year to year change in cooling degree days (CDD) and the change in residential electricity consumption, shown in Figure 8-5, supports this. Similar analyses show that CDD have a lesser impact on the commercial sector and almost no impact on the industrial sector.

While the industrial sector is the least sensitive of the three to weather, it is the most sensitive to the gross state product (GSP). Figure 8-6 shows the scatter diagram for changes in GSP, which is affected by the performance of Indiana's economy, and in industrial electricity consumption. There is no visible relationship between changes in GSP and consumption in the residential and commercial sectors.

A statistical analysis of the historical data provides the correlation coefficients for the changes in electricity consumption for each of the three sectors and for changes in peak demand, cooling degree days and GSP (see Table 8-1). The correlation coefficients vary from -1 to +1, with values near -1 indicating a strong inverse relationship (if one goes up, the other goes down). A value near zero indicates little to no relationship between the two (a change in one does not affect the other). A value near +1 indicates a strong correlation between the two (they tend to go up and down together. The values in Table 8-1 confirm the observed relationships in Figures 8-2 through 8-6.

Table 8-1. Correlation Coefficients

Change in:	Peak Demand	CDD	GSP
Residential Consumption	0.66	0.52	-0.11
Commercial Consumption	0.28	0.37	0.15
Industrial Consumption	-0.01	-0.13	0.63

Figure 8-7 shows the historical percentage of total electricity requirements for which each sector accounts. The industrial sector share generally increases when the economy is performing well and drops when the economy fares poorly, as in 1991 and 2001. This reinforces the notion that consumption in the industrial sector is often hit hardest by an economic slowdown.

The current economic slowdown has had little effect on residential electricity demand; as expected, the slowdown has been most evident in industrial electricity demand.

In summary, the economic slowdown has affected electricity consumption mainly in the industrial sector. This is felt more strongly in the state's total electricity requirements than in its peak demand, which is largely weather dependent and is affected primarily by the residential sector.

Economic Competition between Coal and Natural Gas for Electricity Generation

As Indiana enters a period when new base load capacity will be needed, the question of whether to use coal or natural gas for that capacity is a natural one. To shed some light on the subject, SUFG has compared the relative economics of three types of electricity generators: pulverized coal-fired (PC), combined cycle natural gas-fired (CC) and simple cycle natural gas-fired (CT).

Figure 8-2. Change in Peak Demand vs. Change in Residential Electricity Use

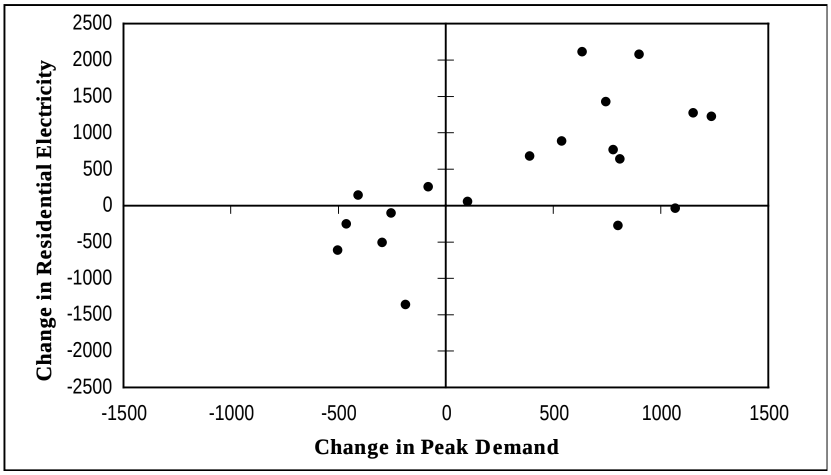


Figure 8-3. Change in Peak Demand vs. Change in Commercial Electricity Use

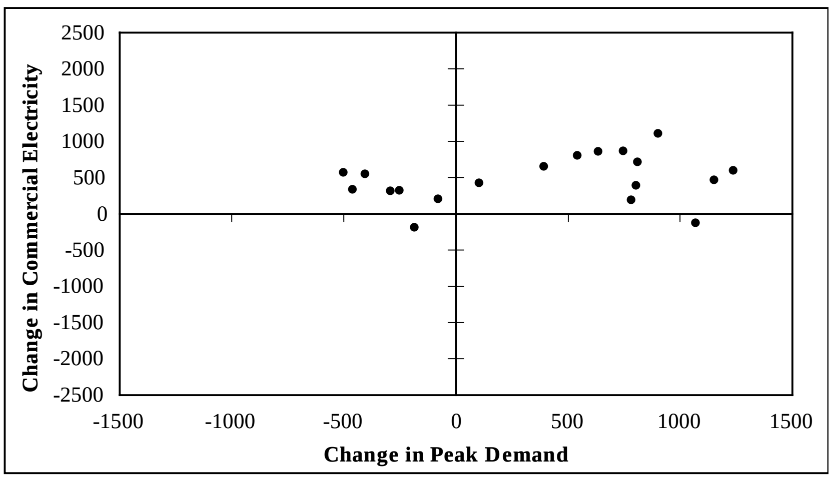


Figure 8-4. Change in Peak Demand vs. Change in Industrial Electricity Use

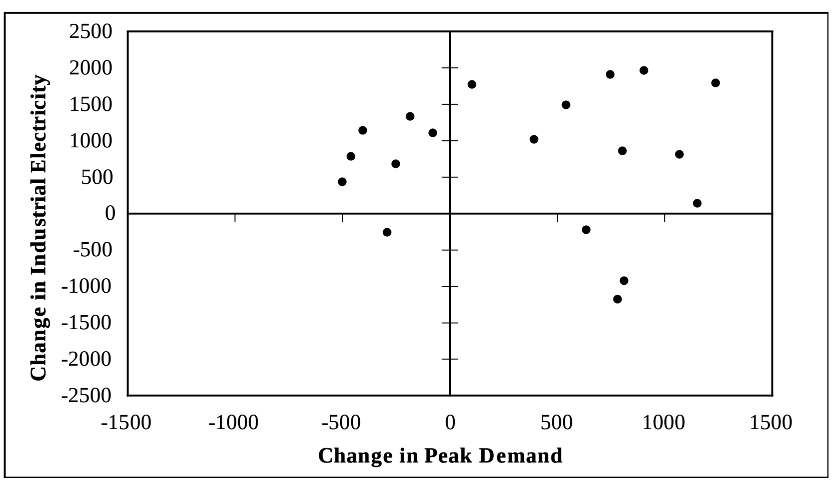


Figure 8-5. Change in CDD vs. Change in Residential Electricity Use

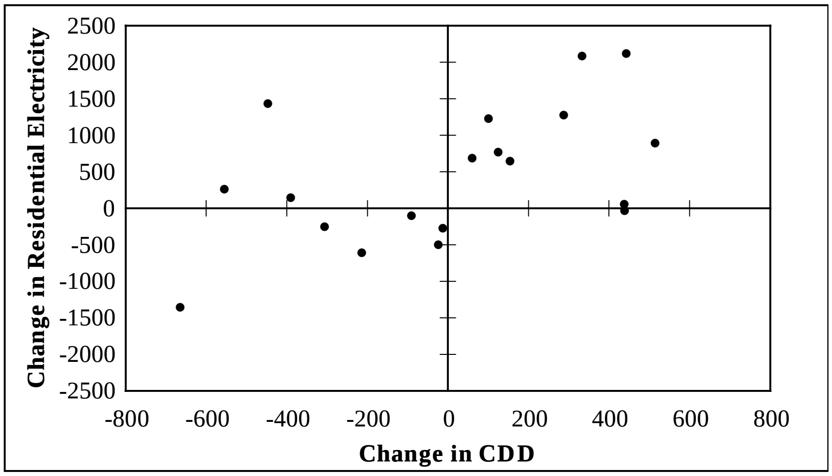


Figure 8-6. Change in GSP vs. Change in Industrial Electricity Use

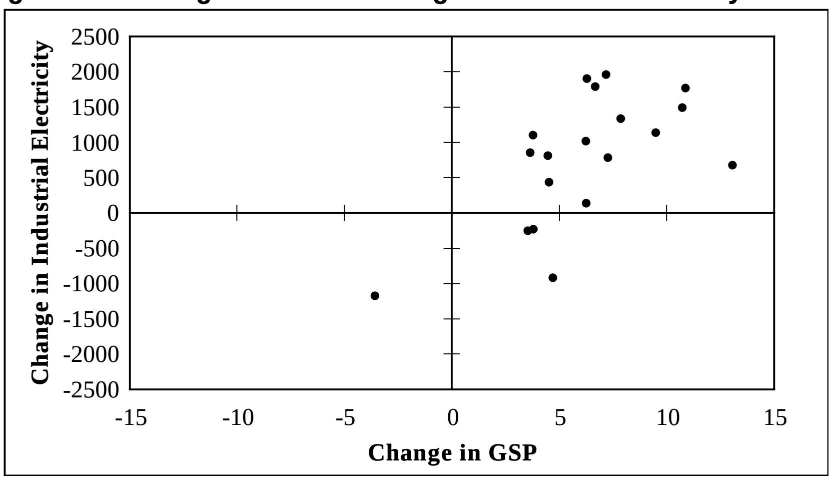
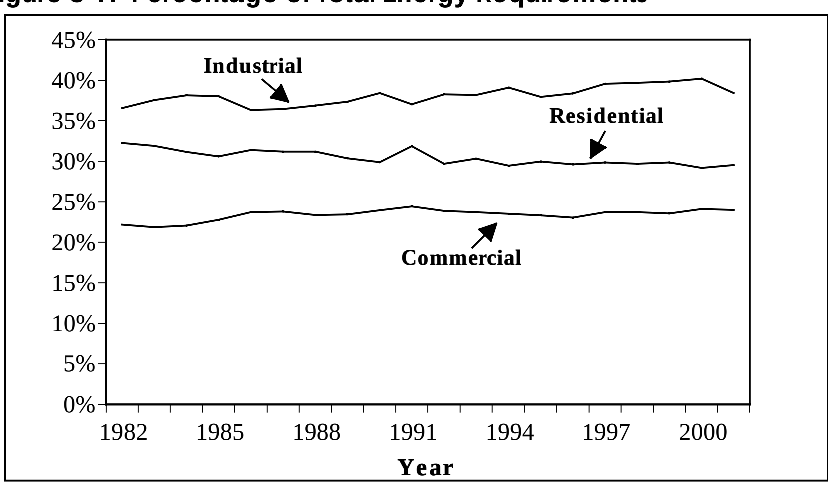


Figure 8-7. Percentage of Total Energy Requirements



As one might expect, three factors are very important when comparing the relative economics of different types of generators. The first is the capital cost associated with purchasing and installing the necessary equipment. The second is the cost to operate the equipment after it is built. For instance, PC units have high construction costs and low operating costs while CTs tend to have lower construction costs and high operating costs. CC units generally have both construction and operating costs that lie between those for PCs and CTs. The third important factor is the expected number of hours of operation.

For this study, the capital costs for each type of unit were determined using the SEPRIL study that SUFG commissioned in 1998, adjusted for inflation. Using assumed values for debt-to-equity ratio, tax rate, interest rate on debt, and capital recovery factor, a needed return on investment in $/kW per year was determined for each type of generator. This was combined with the fixed operating and maintenance (O&M) costs to determine the total fixed costs.

The operating cost for each generator type was determined using the heat rate, a measure of efficiency, contained in the SEPRIL study, along with the variable non-fuel O&M costs. The operating costs were determined for a wide range of assumed fuel costs.

The number of hours of operation was handled by varying the capacity factor of each unit type from 1 to 100 percent. Capacity factor is the ratio of the amount of electricity produced by a generator in a given period and the amount that would be produced if the unit were operating at full load during the entire period. A unit that does not operate at all would have a 0 percent capacity factor while one that operates at full load for the entire period would have a 100 percent capacity factor.

The expected cost of natural gas has a major impact on the relative economics of the different types of generators. Table 8-2 shows the range of capacity factors over which a given unit is most economic, assuming the price of coal is $1/mmBtu and the price of natural gas is $4/mmBtu. Table 8-3 shows the ranges for coal at $1/mmBtu and natural gas at $5/mmBtu.

Table 8-2. Range Over Which Each Unit is Most Economic (Coal at $1/mmBtu, Natural Gas at $4/mmBtu)

Generator Type	Capacity Factor Range
PC	69-100%
CC	38-68%
CT	1-37%

Table 8-3. Range Over Which Each Unit is Most Economic (Coal at $1/mmBtu, Natural Gas at $5/mmBtu)

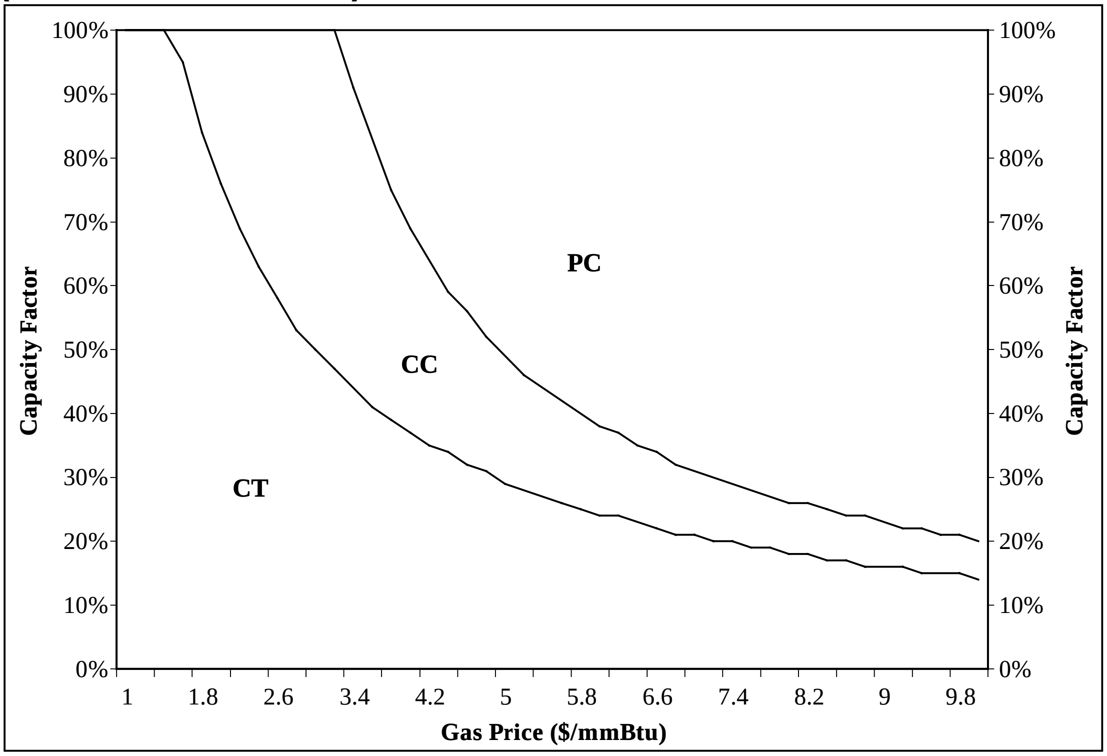
Generator Type	Capacity Factor Range
PC	49-100%
CC	30-48%
CT	1-29%

As expected, the PC generator becomes competitive at lower capacity factors as the price of natural gas increases. If the price of natural gas falls below $3.2/mmBtu, the coal-fired unit cannot compete even at 100 percent capacity factor. Figure 8-8 shows the range over which each generator type is most economic for a wide range of natural gas prices, assuming the price of coal is $1/mmBtu. Similarly, if the price of coal rises, the PC can only compete at higher capacity factors. Table 8-4 shows the ranges of capacity factors for coal at $1/mmBtu and natural gas at $5/mmBtu.

Table 8-4. Range Over Which Each Unit is Most Economic (Coal at $2/mmBtu, Natural Gas at $5/mmBtu)

Generator Type	Capacity Factor Range
PC	80-100%
CC	30-79%
CT	1-29%

Figure 8-8. Most Economic Unit Capacity Factor Range (Coal Price is 1 $/mmBtu)



Recent Trends in New Generation Plant Construction

The wholesale price spikes that occurred in the Midwest in 1998 and 1999 spurred a rush in new generation plans as companies attempted to cash in on the high prices. A combination of increased capacity and milder summer weather has prevented the price spikes from recurring in the past three years. This has resulted in a slowing of new plant announcements and some delays and cancellations of previously announced plants. This section examines recent trends in new generation plant construction in Indiana.

SUFG has been tracking new plant activity since 1998. For purposes of this study, plants are assigned to one of three categories: proposed (either announced or with permits pending), approved (but not yet in operation), or operational.

Figure 8-9 shows the total new capacity in Indiana for each category in each year since 1999. The rapid increase in 1999 and 2000 was driven largely by new proposed projects. The amount of capacity classified as proposed falls thereafter as projects are either approved or cancelled. Over 1,600 MW of new capacity became operational in 2000. That number has risen steadily since then to the current level of almost 2,500 MW.

From 2001 to 2002, the total capacity starts to fall off. As seen in Figure 8-10, this is due to a combination of very little new capacity being proposed in 2002 and a substantial amount being cancelled. In addition, over 2,800 MW of capacity was suspended or delayed in 2002. The delayed plants are still included in their appropriate categories (either proposed or approved) in Figure 8-10, but they do provide further proof that the new generation market has slowed considerably.

Figure 8-9. Total New Capacity in Various Stages

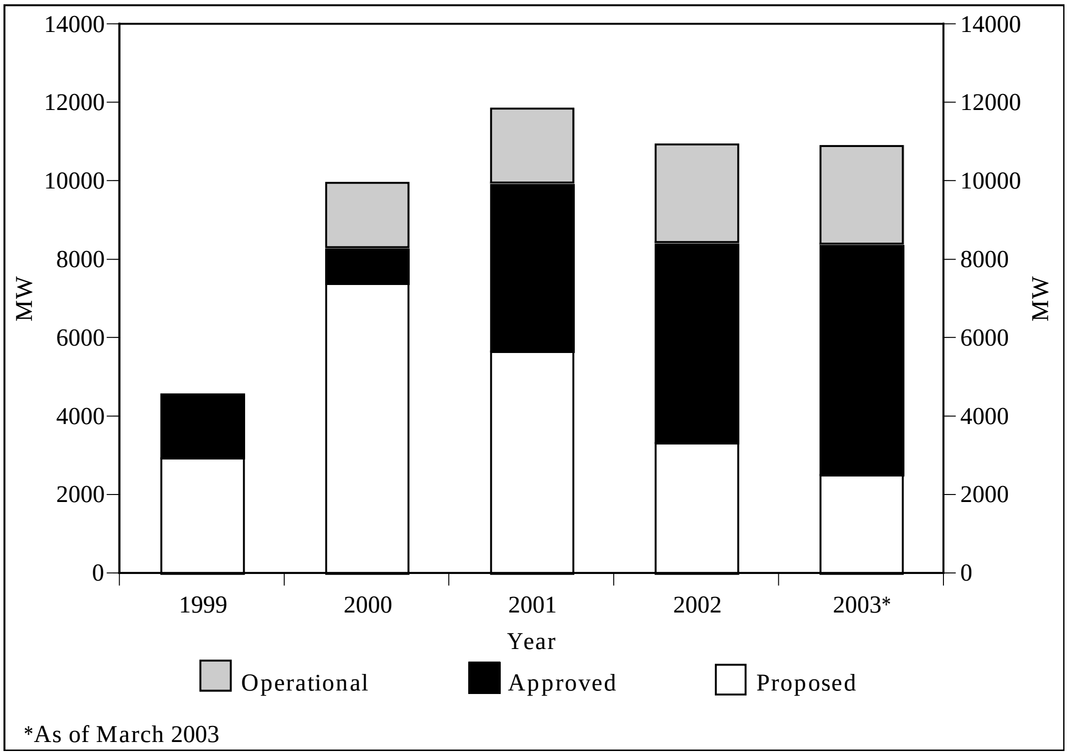
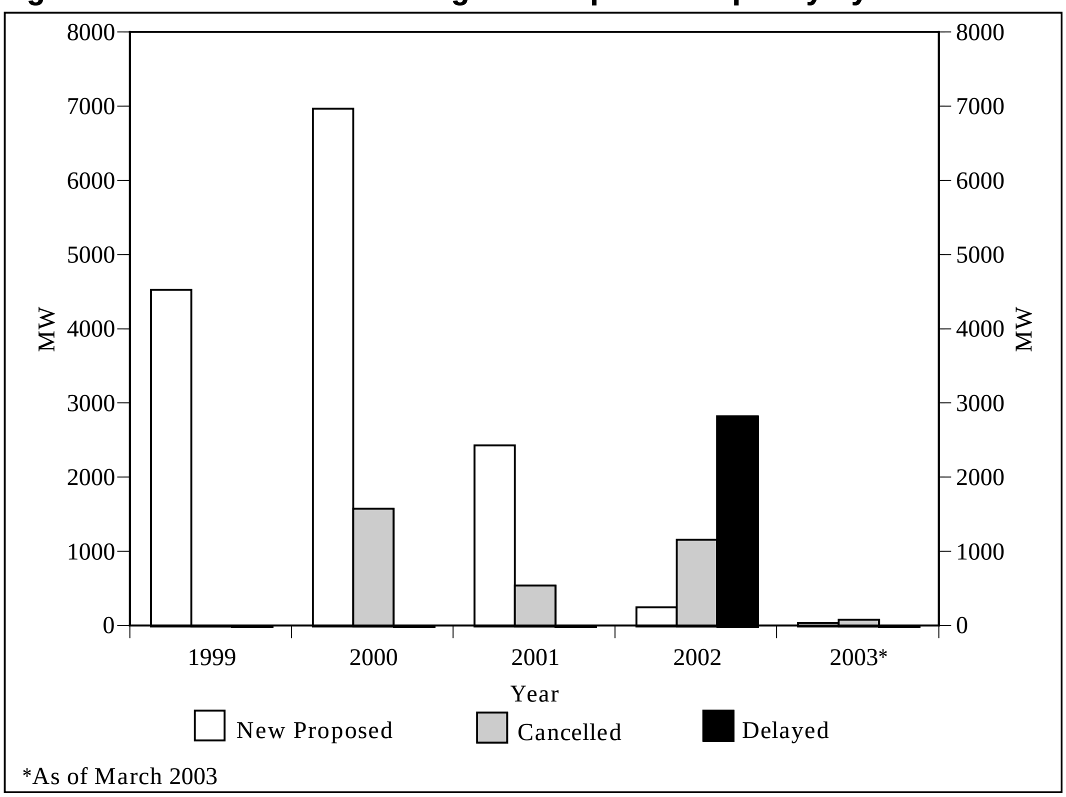


Figure 8-10. Incremental Changes in Proposed Capacity by Year



INDIANA ENERGY, SUMMER PEAK DEMAND AND RATES: SOURCES AND PROJECTIONS

In developing the historical energy, summer peak demand and rates data shown in the body and appendix of this document, SUFG relied on several sources of data. These sources include:

1. FERC Form 1 (IOUs);
2. Rural Utilities Service (RUS) Form 7 or Form 12 (HEREC and WVPA);
3. Uniform Statistical Report (IOUs);
4. Utility Load Forecast Reports (IOUs, HEREC, IMPA and WVPA);
5. Integrated Resource Plan Filings (IOUs, HEREC, IMPA and WVPA);
6. Annual Reports (IOUs, HEREC, IMPA, and WVPA); and
7. SUFG Confidential Data Requests (IOUs, HEREC, IMPA and WVPA).

SUFG relied on public sources where possible, but some generally more detailed data was obtained from Indiana utilities under confidential agreements of nondisclosure. All data presented in this report has been aggregated to total Indiana statewide energy, demand and rates to avoid disclosure.

In most instances the source of SUFG's data can be traced to a particular page of a certain publication, e.g., residential energy sales for an IOU is found on page 304 of FERC Form 1. However, in several cases it is not possible to directly trace a particular number to a public data source. These exceptions arise due to:

1. geographic area served by the utility;
2. classification of sales data; and
3. unavailability of sectoral level sales data.

Both I&M and WVPA serve load in Michigan which SUFG excluded in developing projections for Indiana. Slightly less than 20 percent of I&M's load is in Michigan and WVPA has one member cooperative, Midwest Energy, formerly Fruit Belt Rural Electric Membership Cooperation (REMC), which is located in southern Michigan. Both I&M and WVPA have provided SUFG with data pertaining to their Indiana load.

Some Indiana utilities report sales to the commercial and industrial sectors (SUFG's classification) as sales to one aggregate classification or sales to small and large customers. In order to obtain commercial and industrial sales for these utilities, SUFG has requested data in these classifications from the utilities, developed approximation schemes to disaggregate the sales data, or combined more than one source of data to develop commercial and industrial sales estimates. For example, until recently the Uniform Statistical Report contained industrial sector sales for IOUs. This data can be subtracted from aggregate FERC Form 1 small and large customer sales data to obtain an estimate of commercial sales.

SUFG does not have sectoral level sales data for the unaffiliated REMCs and unaffiliated municipalities. SUFG obtains aggregate sales data from the FERC Form 1, then allocates the sales to residential, commercial industrial and other sales with an allowance for losses. These allocation factors were developed by examining the mix of energy sales for other Indiana REMCs and municipalities. Thus, the sales estimates for unaffiliated REMCs are weighted heavily toward the residential sector and those for unaffiliated municipalities are more evenly balanced between the residential, commercial and industrial sectors.

SUFG's estimates of sales-for-resale are based on FERC Form 1 data and utility provided data. Traditionally, the five IOUs and HEREC have been sellers and IMPA, WVPA and unaffiliated REMCs and municipalities purchasers of sales-for-resale energy and capacity. Out-of-state sales-for-resale by I&M and purchases-for-resale by WVPA are excluded in SUFG's estimates. Additionally, there are some classification differences similar to those in retail sales. SUFG treats the city of Richmond as part of IMPA and includes the city of Jasper as part of the unaffiliated municipalities while I&M and SIGECO, respectively, have treated them as electric utilities. Furthermore, for the above four purchasers, SUFG defines IOU requirement sales as well as all other IOU sales as sales-for-resale.

SUFG's estimates of losses are calculated using a constant percentage loss factor applied to retail sales and sales-for-resale (when appropriate). These loss factors are based on FERC Form 1 data and discussions with Indiana utility personnel.

Total energy requirements for an individual utility are obtained by adding retail sales, sales-for-resale (if any) and losses. Total energy requirements for the state as a whole are obtained by adding retail sales and losses for the ten entities which SUFG models. Sales-for-resale are excluded from the state aggregate total energy requirements to avoid double counting.

Summer peak demand estimates are based upon FERC Form 1 data for the IOUs with the exception of I&M, which provided SUFG with peak demand for their Indiana jurisdiction, and company sources for HEREC, IMPA and WVPA. For the IOUs and HEREC, the reported summer peak demands are adjusted for non-requirement firm sales to Indiana utilities and for SUFG's classification of the city of Richmond and the city of Jasper as previously discussed.

Statewide summer peak demand may not be obtained by simply adding across utilities because of diversity and double counting problems. Diversity refers to the fact that all Indiana utilities do not experience their summer peak demand at the same instance. Due to differences in weather, sectoral mix, end-use saturation, etc., the utilities tend to face their individual summer peak demands at different hours, days, or even months. The double counting issue arises due to sales-for-resale by the IOUs and HEREC to IMPA, WVPA and the unaffiliated REMCs and municipalities. To obtain an estimate of statewide peak demand SUFG employs a two-step procedure. First, the summer peak demand estimates for the IOUs and HEREC are added together and adjusted for diversity. Second, an estimate of IMPA and WVPA capacity online at the time of the statewide summer peak demand is added to the diversity adjusted sum of the IOUs and HEREC summer peak demands. This results in a diversity corrected estimate of statewide summer peak demand and avoids double counting.

The historical energy sales and peak demand data presented in this appendix represent SUFG's accounting of actual historical values. However, data availability for the REMCs and municipalities prior to 1982 is limited and the reported values for 1980 and 1981 include SUFG estimates for the not-for-profit utilities for these years. SUFG believes that any errors in statewide energy sales and demand for 1980 and 1981 are relatively small and concentrated in the residential sector.

In developing the current forecast, SUFG was required to estimate some detailed sector specific data for a few utilities. This data was unavailable from some utilities due to changes in data collection and/or reporting requirements. In the industrial sector, SUFG estimates two digit, Standard Industrial Code sales and revenue data for two IOUs. This data was estimated from total industrial sales data by assuming the same allocation of industrial sales to two-digit level as observed during recent years. SUFG was also unable to obtain sales and revenue data for the commercial sector at the same level of detail from some IOUs. The detailed commercial sector data is necessary to calibrate SUFG's commercial sector model, but since the commercial sector model was not recalibrated for this forecast, no estimation was attempted. The not-for-profit utilities have not traditionally been able to supply SUFG with data at this level of data. However, one not-for-profit utility was unable to provide

SUFG with a breakdown of its member's load by sector. SUFG estimated the sectoral load by applying allocation factors derived from recently observed data.

SUFG feels relatively comfortable with these estimates, but is concerned about the future availability of detailed sector specific data. If data availability proves to be a problem in the future, SUFG will either be forced to develop more sophisticated allocation schemes to support the energy forecasting models or develop less data intensive, detailed energy forecasting models.

SUFG 2003 Base Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales							
		Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
Hist	1980	16612	12418	22544	556	52131	5546	57676	11284
Hist	1981	16118	12470	22907	572	52067	5581	57648	11235
Hist	1982	19927	13725	22600	696	56948	4875	61823	10683
Hist	1983	19950	13665	23476	626	57717	4795	62511	11744
Hist	1984	20153	14274	24678	674	59779	4938	64717	11331
Hist	1985	19707	14651	24480	653	59491	4889	64380	11030
Hist	1986	20410	15429	23618	610	60067	4958	65024	11834
Hist	1987	21154	16144	24694	617	62609	5185	67794	12218
Hist	1988	22444	16808	26546	633	66431	5557	71988	13447
Hist	1989	22251	17205	27394	661	67511	5815	73326	12979
Hist	1990	22037	17659	28311	685	68692	5050	73742	13775
Hist	1991	24215	18580	28141	660	71595	4439	76034	14403
Hist	1992	22916	18456	29540	649	71561	5645	77207	14209
Hist	1993	25060	19627	31562	544	76793	5876	82669	15103
Hist	1994	25176	20116	33395	541	79227	6219	85446	15198
Hist	1995	26513	20646	33590	540	81290	7225	88514	16342
Hist	1996	26833	20909	34755	567	83064	7573	90637	16254
Hist	1997	26792	21295	35499	569	84155	5618	89773	15993
Hist	1998	27745	22158	37052	560	87515	5914	93429	16527
Hist	1999	29238	23089	39020	584	91932	6069	98001	17266
Hist	2000	28684	23721	39513	646	92563	5769	98332	16757
Hist	2001	29516	23975	38398	644	92532	7401	99933	17531
Frcst	2002	29988	24206	37697	644	92535	7399	99934	17762
Frcst	2003	30615	24855	38973	644	95087	7593	102680	18231
Frcst	2004	31256	25663	40224	644	97788	7804	105592	18934
Frcst	2005	31873	26451	41101	644	100068	7984	108053	19398
Frcst	2006	32335	27195	41650	644	101824	8120	109944	19633
Frcst	2007	32742	27960	42166	644	103512	8246	111758	19845
Frcst	2008	33244	28751	42736	644	105376	8393	113769	20047
Frcst	2009	33785	29524	43304	644	107257	8541	115798	20400
Frcst	2010	34433	30327	43994	644	109398	8717	118115	20794
Frcst	2011	35103	31145	44751	644	111644	8902	120546	21224
Frcst	2012	35742	31923	45512	644	113822	9077	122899	21581
Frcst	2013	36461	32765	46386	644	116256	9276	125532	22044
Frcst	2014	37148	33582	47272	644	118647	9469	128116	22410
Frcst	2015	37903	34462	48207	644	121216	9679	130895	22900
Frcst	2016	38709	35355	49196	644	123904	9901	133805	23413
Frcst	2017	39612	36247	50200	644	126703	10135	136839	23945
Frcst	2018	40427	37184	51296	644	129552	10368	139920	24489
Frcst	2019	41285	38133	52471	644	132534	10611	143145	25057
Frcst	2020	42444	39309	53713	644	136111	10956	147067	25709
Frcst	2021	43317	40240	54623	644	138824	11189	150013	26231

Average Compound Growth Rates (%)

Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1980-1985	3.48	3.36	1.66	3.27	2.68	-2.49	2.22	-0.45
1985-1990	2.26	3.81	2.95	0.97	2.92	0.65	2.75	4.55
1990-1995	3.77	3.17	3.48	-4.65	3.43	7.42	3.72	3.48
1995-2000	1.59	2.82	3.30	3.65	2.63	-4.40	2.13	0.50
2000-2005	2.13	2.20	0.79	-0.06	1.57	6.71	1.90	2.97
2005-2010	1.56	2.77	1.37	0.00	1.80	1.77	1.80	1.40
2010-2015	1.94	2.59	1.85	0.00	2.07	2.12	2.08	1.95
2015-2021	2.25	2.62	2.10	0.00	2.29	2.45	2.30	2.29
2002-2021	1.95	2.71	1.97	0.00	2.16	2.20	2.16	2.07

SUFG 2003 Low Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
Hist	1980	16612	12418	22544	556	52131	5546	57676	11284
Hist	1981	16118	12470	22907	572	52067	5581	57648	11235
Hist	1982	19927	13725	22600	696	56948	4875	61823	10683
Hist	1983	19950	13665	23476	626	57717	4795	62511	11744
Hist	1984	20153	14274	24678	674	59779	4938	64717	11331
Hist	1985	19707	14651	24480	653	59491	4889	64380	11030
Hist	1986	20410	15429	23618	610	60067	4958	65024	11834
Hist	1987	21154	16144	24694	617	62609	5185	67794	12218
Hist	1988	22444	16808	26546	633	66431	5557	71988	13447
Hist	1989	22251	17205	27394	661	67511	5815	73326	12979
Hist	1990	22037	17659	28311	685	68692	5050	73742	13775
Hist	1991	24215	18580	28141	660	71595	4439	76034	14403
Hist	1992	22916	18456	29540	649	71561	5645	77207	14209
Hist	1993	25060	19627	31562	544	76793	5876	82669	15103
Hist	1994	25176	20116	33395	541	79227	6219	85446	15198
Hist	1995	26513	20646	33590	540	81290	7225	88514	16342
Hist	1996	26833	20909	34755	567	83064	7573	90637	16254
Hist	1997	26792	21295	35499	569	84155	5618	89773	15993
Hist	1998	27745	22158	37052	560	87515	5914	93429	16527
Hist	1999	29238	23089	39020	584	91932	6069	98001	17266
Hist	2000	28684	23721	39513	646	92563	5769	98332	16757
Hist	2001	29516	23975	38398	644	92532	7401	99933	17531
Frcst	2002	29987	24206	37697	644	92535	7399	99933	17762
Frcst	2003	30613	24855	38973	644	95085	7593	102678	18231
Frcst	2004	31253	25663	40224	644	97785	7804	105589	18933
Frcst	2005	31843	26228	40816	644	99532	7941	107473	19300
Frcst	2006	32261	26618	40850	644	100374	8005	108379	19370
Frcst	2007	32611	27017	40774	644	101047	8051	109098	19401
Frcst	2008	33040	27431	40710	644	101826	8111	109938	19406
Frcst	2009	33511	27817	40605	644	102578	8171	110748	19555
Frcst	2010	34086	28219	40581	644	103530	8254	111783	19735
Frcst	2011	34687	28610	40598	644	104539	8342	112882	19941
Frcst	2012	35247	28977	40593	644	105461	8418	113879	20071
Frcst	2013	35880	29382	40672	644	106578	8513	115091	20298
Frcst	2014	36491	29769	40745	644	107649	8603	116252	20423
Frcst	2015	37146	30172	40817	644	108779	8698	117477	20655
Frcst	2016	37860	30592	40909	644	110005	8803	118808	20903
Frcst	2017	38672	31003	40968	644	111287	8917	120204	21162
Frcst	2018	39393	31433	41061	644	112531	9021	121553	21416
Frcst	2019	40155	31874	41170	644	113844	9131	122975	21685
Frcst	2020	41161	32456	41247	644	115509	9307	124816	22000
Frcst	2021	41953	32863	41099	644	116559	9401	125961	22228

Average Compound Growth Rates (%)

Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1980-1985	3.48	3.36	1.66	3.27	2.68	-2.49	2.22	-0.45
1985-1990	2.26	3.81	2.95	0.97	2.92	0.65	2.75	4.55
1990-1995	3.77	3.17	3.48	-4.65	3.43	7.42	3.72	3.48
1995-2000	1.59	2.82	3.30	3.65	2.63	-4.40	2.13	0.50
2000-2005	2.11	2.03	0.65	-0.06	1.46	6.60	1.79	2.87
2005-2010	1.37	1.47	-0.12	0.00	0.79	0.77	0.79	0.45
2010-2015	1.73	1.35	0.12	0.00	0.99	1.05	1.00	0.92
2015-2021	2.05	1.43	0.11	0.00	1.16	1.31	1.17	1.23
2002-2021	1.78	1.62	0.46	0.00	1.22	1.27	1.23	1.19

SUFG 2003 High Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
Hist	1980	16612	12418	22544	556	52131	5546	57676	11284
Hist	1981	16118	12470	22907	572	52067	5581	57648	11235
Hist	1982	19927	13725	22600	696	56948	4875	61823	10683
Hist	1983	19950	13665	23476	626	57717	4795	62511	11744
Hist	1984	20153	14274	24678	674	59779	4938	64717	11331
Hist	1985	19707	14651	24480	653	59491	4889	64380	11030
Hist	1986	20410	15429	23618	610	60067	4958	65024	11834
Hist	1987	21154	16144	24694	617	62609	5185	67794	12218
Hist	1988	22444	16808	26546	633	66431	5557	71988	13447
Hist	1989	22251	17205	27394	661	67511	5815	73326	12979
Hist	1990	22037	17659	28311	685	68692	5050	73742	13775
Hist	1991	24215	18580	28141	660	71595	4439	76034	14403
Hist	1992	22916	18456	29540	649	71561	5645	77207	14209
Hist	1993	25060	19627	31562	544	76793	5876	82669	15103
Hist	1994	25176	20116	33395	541	79227	6219	85446	15198
Hist	1995	26513	20646	33590	540	81290	7225	88514	16342
Hist	1996	26833	20909	34755	567	83064	7573	90637	16254
Hist	1997	26792	21295	35499	569	84155	5618	89773	15993
Hist	1998	27745	22158	37052	560	87515	5914	93429	16527
Hist	1999	29238	23089	39020	584	91932	6069	98001	17266
Hist	2000	28684	23721	39513	646	92563	5769	98332	16757
Hist	2001	29516	23975	38398	644	92532	7401	99933	17531
Frcst	2002	29997	24206	37697	644	92544	7400	99944	17764
Frcst	2003	30634	24855	38972	644	95106	7595	102701	18235
Frcst	2004	31287	25663	40224	644	97818	7807	105625	18940
Frcst	2005	32205	26674	41383	644	100906	8054	108960	19559
Frcst	2006	33021	27754	42449	644	103869	8288	112158	20021
Frcst	2007	33704	28892	43581	644	106821	8516	115337	20469
Frcst	2008	34395	30068	44808	644	109915	8761	118676	20897
Frcst	2009	35072	31227	46067	644	113010	9005	122015	21471
Frcst	2010	35865	32451	47476	644	116436	9283	125719	22098
Frcst	2011	36688	33676	48980	644	119988	9572	129560	22768
Frcst	2012	37479	34882	50514	644	123520	9854	133374	23373
Frcst	2013	38360	36180	52210	644	127394	10168	137562	24102
Frcst	2014	39227	37471	53972	644	131314	10485	141799	24746
Frcst	2015	40159	38837	55834	644	135474	10824	146299	25526
Frcst	2016	41121	40238	57773	644	139777	11177	150954	26331
Frcst	2017	42180	41641	59760	644	144226	11546	155772	27164
Frcst	2018	43163	43096	61892	644	148796	11920	160717	28023
Frcst	2019	44176	44604	64130	644	153555	12309	165863	28914
Frcst	2020	45589	46462	66676	644	159371	12852	172223	29968
Frcst	2021	46605	47987	68751	644	163988	13242	177230	30832

Average Compound Growth Rates (%)

Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1980-1985	3.48	3.36	1.66	3.27	2.68	-2.49	2.22	-0.45
1985-1990	2.26	3.81	2.95	0.97	2.92	0.65	2.75	4.55
1990-1995	3.77	3.17	3.48	-4.65	3.43	7.42	3.72	3.48
1995-2000	1.59	2.82	3.30	3.65	2.63	-4.40	2.13	0.50
2000-2005	2.34	2.37	0.93	-0.06	1.74	6.90	2.07	3.14
2005-2010	2.18	4.00	2.79	0.00	2.90	2.88	2.90	2.47
2010-2015	2.29	3.66	3.30	0.00	3.08	3.12	3.08	2.93
2015-2021	2.51	3.59	3.53	0.00	3.23	3.42	3.25	3.20
2002-2021	2.35	3.67	3.21	0.00	3.06	3.11	3.06	2.94

Indiana Base Average Retail Rates (Cents/kWh) (In 2001 Dollars)

Year		Res	Com	Ind	Average
Hist	1980	8.87	9.40	6.52	7.96
Hist	1981	9.04	9.28	6.60	8.00
Hist	1982	10.04	9.88	7.28	8.82
Hist	1983	10.44	9.99	7.34	8.96
Hist	1984	10.57	10.06	7.37	9.01
Hist	1985	10.79	9.99	7.24	9.01
Hist	1986	10.96	10.31	7.46	9.31
Hist	1987	10.51	9.97	6.74	8.76
Hist	1988	9.89	9.12	6.40	8.18
Hist	1989	9.23	7.81	5.83	7.36
Hist	1990	8.72	7.38	5.52	6.93
Hist	1991	8.14	6.90	5.23	6.57
Hist	1992	8.06	6.80	5.08	6.39
Hist	1993	7.58	6.37	4.76	6.01
Hist	1994	7.62	6.36	4.73	5.97
Hist	1995	7.47	6.29	4.53	5.86
Hist	1996	7.46	6.27	4.56	5.84
Hist	1997	7.59	6.19	4.48	5.81
Hist	1998	7.60	6.18	4.44	5.79
Hist	1999	7.37	6.04	4.23	5.59
Hist	2000	7.06	5.72	4.14	5.37
Hist	2001	6.92	5.75	4.02	5.31
Frcst	2002	6.90	5.74	4.02	5.32
Frcst	2003	6.80	5.66	3.98	5.25
Frcst	2004	6.76	5.59	3.89	5.17
Frcst	2005	6.86	5.67	3.93	5.23
Frcst	2006	6.95	5.73	3.96	5.29
Frcst	2007	6.92	5.71	3.93	5.27
Frcst	2008	6.93	5.72	3.94	5.28
Frcst	2009	6.95	5.73	3.94	5.29
Frcst	2010	6.96	5.73	3.94	5.29
Frcst	2011	6.95	5.73	3.93	5.29
Frcst	2012	6.93	5.71	3.91	5.27
Frcst	2013	6.86	5.66	3.88	5.22
Frcst	2014	6.82	5.63	3.86	5.20
Frcst	2015	6.76	5.59	3.84	5.16
Frcst	2016	6.68	5.53	3.80	5.11
Frcst	2017	6.62	5.49	3.77	5.07
Frcst	2018	6.50	5.40	3.71	4.98
Frcst	2019	6.40	5.32	3.66	4.90
Frcst	2020	6.44	5.40	3.76	4.98
Frcst	2021	6.41	5.38	3.74	4.96

Average Compound Growth Rates (%)

Year	Res	Com	Ind	Average
1980-1985	4.00	1.23	2.11	2.50
1985-1990	-4.17	-5.88	-5.29	-5.10
1990-1995	-3.04	-3.14	-3.84	-3.32
1995-2000	-1.14	-1.90	-1.78	-1.71
2000-2005	-0.56	-0.17	-1.08	-0.52
2005-2010	0.28	0.23	0.05	0.23
2010-2015	-0.58	-0.51	-0.52	-0.52
2015-2021	-0.87	-0.64	-0.42	-0.63
2002-2021	-0.38	-0.34	-0.38	-0.36

Notes:
--Energy-weighted average rates for Indiana IOUs
--Results for the 2001 SUFG low and high scenarios are very similar and not reported

SUFG 2003 Base Total Demand and Supply (MW) for Indiana

Year	Summer Demand	Available Capacity	Approved Resource Additions			Projected Resource Additions			Incremental Change	Reserve Margin
			Peaking	Cycling	Baseload	Peaking	Cycling	Baseload		
1980	11284	14462	0	0	0				0	28
1981	11235	14537	75	0	0				0	29
1982	10683	15669	0	0	1288				0	47
1983	11744	16506	0	0	993				0	41
1984	11331	16639	0	0	533				0	47
1985	11030	16639	0	0	0				0	51
1986	11834	17678	0	0	1109				-70	49
1987	12218	17678	0	0	0				0	45
1988	13447	17678	0	0	0				0	31
1989	12979	17678	0	0	0				0	36
1990	13775	18442	0	0	596				0	34
1991	14403	18507	0	0	0				0	28
1992	14209	18977	220	0	0				0	34
1993	15103	19128	100	0	0				0	27
1994	15198	18885	80	0	0				-328	24
1995	16342	19010	80	0	0				-11	16
1996	16254	19216	0	143	27				0	18
1997	15993	19084	0	0	0				0	19
1998	16527	19050	0	0	45				0	15
1999	17266	18920	0	0	0				0	10
2000	16757	19178	0	0	0				0	14
2001	17531	20294	0	0	0				0	16
2002	17762	20749	231	0	0				455	17
2003	18231	21056	841	196	0	250	235	60	-243	15
2004	18934	21762	330	0	0	30	435	180	66	15
2005	19398	22303				135	165	200	41	15
2006	19633	22563				90	55	220	-100	15
2007	19845	22815				105	-50	150	52	15
2008	20047	23065				40	-100	250	50	15
2009	20400	23447				110	75	240	-28	15
2010	20794	23922				-40	25	280	205	15
2011	21224	24422				105	155	300	-60	15
2012	21581	24817				105	135	280	-125	15
2013	22044	25337				105	95	320	0	15
2014	22410	25797				135	105	320	-100	15
2015	22900	26354				105	95	355	-3	15
2016	23413	26834				40	60	385	0	15
2017	23945	27424				95	65	440	0	15
2018	24489	28074				115	95	430	0	15
2019	25057	28734				115	85	450	0	15
2020	25709	29461				275	35	595	-163	15
2021	26231	30071				115	75	410	0	15

Acid Rain Rainfall occurring when atmospheric water vapor combines with oxides of sulfur and nitrogen (from both man-made and natural sources) to form sulfuric or nitric acid. Natural rainfall is slightly acidic due to the presence of carbon dioxide (CO2) in the atmosphere which forms a mild carbonic acid. If rainfall becomes too acidic, it may cause environmental damage.

Additions (To Utility Plant)

Gross - Expenditures for construction (may or may not include interest and other overheads charged to construction) and utility plant purchased and acquired, in a specific period.

Net - Gross additions less retirements and adjustments of a utility plant. It is the net change in a utility plant between two dates.

Average A number that typifies a set of numbers of which it is a function.

Average Compound Growth Rate (ACGR) A commonly used measure to summarize the overall rate of change in percentages of any forecast time series. Only the beginning and ending points plus the number of intervening years are necessary to define an average compound growth rate. For example, in this forecast ACGRs were calculated as follows:

$$\left[\left[\left(\frac{Value\ of\ Year\ 2021}{Value\ of\ Year\ 2001}\right)^{\left(\frac{1}{2021-2002}\right)}\right]-1\right]*100$$

Base Case (Base Scenario) The most likely projection with an equal chance of being high or low.

Base Load Demand The minimum load over a given period of time.

Base Load Plant An electricity generation plant normally operated to meet all or part of the minimum load demand of a power company's system over a given amount of time.

Base Load Unit Generation unit, which is designed for nearly continuous operation at or near full capacity to provide all or part of the base load demand.

Base Year The last year that actual data is available and from which all forecast series emanate.

British Thermal Unit (Btu) The standard unit for measuring quantity of heat energy, such as the heat content of fuel. It is the amount of heat energy necessary to raise the temperature of one pound of water one Fahrenheit degree. There are 3412 Btu in 1 kWh.

Calibration The process of adjusting model parameters such that when tested for a historical period, the model can produce results that are as close to historical data as possible. This is sometimes referred to as backcasting.

Capacity The load for which a generating unit, generating station, or other electrical apparatus is rated either by the user or by the manufacturer.

Base Load - Capacity of the generating equipment normally operated to serve continuous loads.

Peaking - That portion of the total generation capacity that is used to serve the load under adverse conditions, such as periods of unusually high load or the failure of a base load or intermediate unit. Peaking capacity is not used under normal conditions and may be activated quickly under adverse conditions.

Capacity Factor The ratio, as expressed as a percentage, of the average operating load of an electric power generating system for a period of time to the capacity rating of the system during that period, calculated as follows:

$$\frac{Average\ Load}{Rated\ Capacity}\ X\ 100\%$$

Capacity Margin The percentage difference between rated capacity and peak load divided by rated capacity. (See also *Reserve Margin)* Capacity margin is calculated as:

$$\frac{Rated\ Capacity\ - Peak\ Load}{Rated\ Capacity}\ X\ 100\%$$

Certificate of Convenience and Necessity A special permit (which supplements the franchise), commonly issued by a state commission, which authorizes a utility to engage in business, construct facilities, or perform some other service.

Clean Air Act (CAA) The primary federal law governing the regulation of emissions into the atmosphere. Originally passed in 1963, it has been amended several times with major changes occurring in 1970 and 1990. In 1970, primary responsibility for administering the CAA was given to the newly created Environmental Protection Agency. This act required promulgation and ongoing enforcement of National Ambient Air Quality Standards and National Emission Standards for Hazardous Air Pollutants that limit the maximum local concentrations of various air pollutants. In addition, the act limits the amount of various pollutants that vehicles may emit. The 1990 amendments set stricter provisions for motor vehicle emissions, attainment of the national ambient air quality standards and specific restrictions on use or emissions of chlorofluorocarbons, NO_x and sulfur dioxide (SO_2). The SO_2 restrictions involve a system of tradeable emissions allowances.

Combined Cycle A combustion turbine installation using waste heat boilers to capture exhaust energy for steam generation.

Combustion Turbine An electric generating unit in which the prime mover is a gas turbine engine. (See also *Peaking Unit*)

Competition A business environment in which more than one supplier can potentially serve a market and any customer has the ability to choose the supplier that best serves its needs.

Cooling Degree-Days (CDD) A measure of how hot a location was over a period of time, relative to a base temperature. The cooling degree-days for a single day is the difference between that day's average temperature and the base temperature if the daily average is greater than the base; and zero if the daily average temperature is less than or equal to the base temperature. (See also *Heating Degree-Days*)

Cooperative, Rural Electric Membership (REMC) A consumer-owned utility established to provide electric service in rural portions of the United States. Consumer cooperatives are incorporated under the laws of the 46 states in which they operate. A consumer cooperative is a non-profit enterprise, owned and controlled by the people it serves. These systems obtain most of their financing through insured and guaranteed loans administered by the Rural Utilities Service (formerly the Rural Electrification Administration) and from their own financing institution, the National Rural Utilities Cooperative Financing Corporation.

Deflator An index which is used to adjust for the purchasing power of a dollar.

Demand *(Economic)* The inverse relationship between the price of a good and the quantity demanded.

Demand *(Electric Power)* The instantaneous load on transmission, distribution, substation and generation facilities.

Demand-Side Management (DSM) The planning, implementation and monitoring of utility activities designed to influence customer use of electricity in ways that will produce desired changes in a utility's load shape (i.e., changes in the time pattern and magnitude of a utility's load). Utility programs falling under the umbrella of DSM include: load management, new uses of electricity, energy conservation, electrification, customer generation adjustments in market share and innovative rates. DSM includes only those activities that involve a deliberate intervention by the utility to alter the load shape. These changes must produce benefits to both the utility and its customers.

Demographics Data on population attributes such as age, income, number of household members, schooling, etc. Demographic data is used to identify and segment customer types.

Discrete Choice Microsimulation A methodology employed by the CEDMS (commercial end-use) model wherein detailed equipment choices by customers are simulated across a variety of distinct technologies for a sample of representative commercial establishments.

Dispatch The operating control of an integrated electric system to: (1) assign generation levels to specific generating stations and other sources of supply to effect the most reliable and economical supply as the total of the significant area loads rises or falls; (2) control operations and maintenance of high-voltage lines, substations and equipment, including administration of safety procedures; (3) operate the interconnection; and (4) schedule energy transactions with other interconnected electric utilities.

Economic Activity A causal factor used in energy models as one of the explanatory variables. In SUFG's energy modeling system, each of the sectoral energy forecasting models is driven by economic activity assumptions, i.e., personal income, population, commercial employment and industrial output.

Econometric Forecasting An approach used in forecasting that utilizes econometric modeling principles.

Econometric Model A single or multi-variant statistical approach to explain the variations in an economic variable by the use of changes in other observed independent variable(s).

Economic Driver(s) Generally used to refer to elements of a small set of primary causal elements in an economic system.

Electric Power Research Institute (EPRI) Founded in 1972 by the nation's electric utilities to develop and manage technology programs for improving electric power production, distribution and utilization.

Elasticity The ratio of the percentage change in one variable to the percentage change in another variable, where *X* and *Y* represent variables and *t* denotes time.

$$Elasticity = ((X_t - X_{t-1})/X_{t-1}) \,/\, ((Y_t - Y_{t-1})/Y_{t-1})$$

Electric Energy-Weighted Commercial Floor Space Index This index is a proxy for the physical size of the commercial sector. This index is preferable to other commonly used proxies such as non-manufacturing employment due to the variability of electric intensity among building types. Originally constructed for SUFG's 1987 forecast, the index is annually updated. The weights were reestimated by Jerry Jackson and Associates based in part on data from the 1990 census.

Emissions Air, soil, or water pollutants emitted into a community's atmosphere, soil, or water supply.

End Use Uses of energy including, but not limited to, space heating, water heating, lighting, air conditioning, refrigeration, cooking, electromotive and other processes.

End-Use Model A model focusing on end-use technologies.

End-Use Saturation The percentage of households, building types, etc., that include equipment to provide an end-use service, such as air-conditioning.

Energy As commonly used in the electric utility industry refers to kilowatthours, as opposed to "demand" which refers to kilowatts.

Energy Information Administration (EIA) Since October 1977, the Energy Information Administration (EIA) of the Department of Energy (DOE) has been responsible for collecting and publishing statistical data on energy production, consumption, prices, resources and projections of supply and demand. The EIA serves as an independent statistical and analytical agency within the DOE.

Energy Policy Act (EPAct) A comprehensive federal act passed in 1992 generally designed to improve the efficiency of energy use in the United States. Some of the more important Titles in EPAct consisted of the following major provisions:

Title I - Energy Efficiency -- requires more stringent standards for building, lighting, industrial and appliance efficiencies and encourages investments by utilities in energy conservation measures.

Title III - Alternative Fuels (General) -- requires the federal government to purchase a specified number of alternative fuel vehicles each year between 1993 and 1995 and to devote an increasing percentage of its fleet vehicle purchases to alternate fuel vehicles. By 1999 and thereafter, 75 percent of fleet vehicle purchases must use alternate fuels.

Title IV - Alternative Fuels (Non-Federal Programs) -- provides for federally-regulated gas and electric company recovery of costs related to research on alternative fuel vehicles. Also provides incentive payments to various states to encourage development of programs designed to encourage use of alternative fuel vehicles and subsidized loans to small businesses that operate fleets and convert or purchase alternative fuel vehicles.

Title V - Availability and Use of Replacement Fuels, Alternative Fuels and Alternative Fueled Private Vehicles -- requires electric utility and alternative fuel providers devote an increasing percentage of their purchases of light duty motor vehicles to alternative fuel vehicles.

Title VI - Electric Motor Vehicles -- provides subsidies for purchase and demonstration of electric motor vehicles and subsidies for research, development or demonstration of electric vehicle infrastructure and support systems.

Title VII - Electricity -- establishes a new legal category of Exempt Wholesale Generators (EWGs) that are exempt from various restrictions of the Public Utility Holding Company Act. This provision allows public utilities to own and operate separate wholesale generating facilities and cogeneration facilities. In addition, utilities are required to provide power marketing agency, or other person generating electric energy for sale for resale.

In addition, some of the other provisions of EPAct revise the rules for nuclear power plant licensing, establish the United States Enrichment Corporation to take over regulation and marketing of enriched uranium, provide funds for research and development of clean coal technologies, as well as funds for research on the health effects of electromagnetic fields and provide a subsidy for electricity produced from renewable sources.

Envelope Retrofits The process of replacing or augmenting the insulation, windows, air exchange, etc. of a building.

Estimate To calculate approximately the extent or amount of.

Exogenous Variable A variable determined outside the system of interest.

Explanatory Variables A variable that is assumed to be determined by forces external to a model and is accepted as given data. These variables are used in an econometric model to explain the changes in the dependent variable.

Firm Purchase A form of contract under which power or power-producing capacity is intended to be available at all times during the period covered by a commitment, even under adverse conditions.

Forecast Horizon The period of time from the start of a forecast until the end of a forecast.

Gas-Fired Combustion Turbine An electric generating unit in which the prime mover is a gas-fired turbine engine.

Generating Unit An electric generator together with its prime mover.

Generation, Electric The act or process of transforming other forms of energy into electric energy, or to the amount of electric energy so produced, expressed in kilowatthours.

Gross - The total amount of electric energy produced by the generating units in a generating station or stations measured at the generator terminals.

Net - Gross generation less kilowatthours used at the generating station(s).

Gigawatt (GW) One gigawatt equals one billion watts, 1 million kilowatts or 1 thousand megawatts.

Gigawatthour (GWh) One gigawatthour equals one billion watthours.

Gross Domestic Product (GDP) The best measure of the aggregate value of national output. GDP is equal to Gross National Product net of resident's income from economic activity abroad (i.e., exports, repatriated profits, interest and so on) and property held abroad minus the corresponding income of nonresidents in the country (i.e., imports and profits and interests and dividends taken out of the country).

Gross National Product (GNP) The total dollar value of market oriented goods and services produced by the economy. When the proper accounting adjustments are made, this is equivalent to adding up total income and taxes in the economy in a country; or total sales or purchases or the total value of each industry's output.

Gross State Product (GSP) Used to refer to the part of GDP originating within any state.

Heat Rate A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatthour. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net kilowatthour generation.

Heterogeneity Consisting of dissimilar ingredients.

Household Formation The demographic and economic process that describes the creation of a household.

Inflation Rate The rate of change of an economy's price level that is shared by most products.

Input Information fed into a system.

Integrated Resource Planning A process by which utilities and regulatory commission assess the cost of and choose among various resource options.

Intensity Used in the context of disaggregating observed and forecast changes in electricity use into two components:

-- One related to changes in the level of relevant economic activities generally outside and not sensitive to the cost of electricity. Primary examples are residential households, commercial building floorspace and the level of industrial production.

-- One which is directly related to the price of electricity and describes the rate of electricity use per unit level of the relevant economic activity, e.g., kWh per residential customer, kWh per unit of commercial building floorspace, kWh per unit of industrial output.

Interruptible Rate A lower rate offered by a utility to a customer that allows the utility to interrupt electric service.

Investor-Owned Utility Electric utility organized as a taxpaying business usually financed by the sale of securities in the free market and whose properties are managed by representatives regularly elected by their shareholders. Investor-owned electric utilities, which may be owned by an individual proprietor or a small group of people, are usually corporations owned by the general public.

Kilowatt (kW) One kilowatt equals 1,000 watts.

Kilowatthour (kWh) The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour. One kilowatthour equals 1,000 watthours.

Load Diversity The difference between the sum of two or more individual loads and the coincident or combined maximum load, usually measured in kilowatts.

Load Factor The ratio, expressed as a percentage, of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. Load factor also may be derived by dividing the kilowatthours in the period by the product of the maximum demand in kilowatts and the number of hours in the period.

$$\text{Load Factor} = \frac{\text{Average Demand}}{\text{Peak Demand}} \times 100\% \text{ or}$$

$$\text{Load Factor} = \frac{\text{Energy}}{\text{Time}} \times 100\%$$

Logit Model A statistical model used to explain the choice between two or more possibilities.

Log-Log Econometric Model A statistical model in which the logarithm of the dependent variable is linearly related to the logarithm(s) of the independent variable(s).

Long Run A period of time long enough to permit the variation of all inputs to production, including capital and technological change. (See *Short Run)*

Loss (Losses) The general term applied to energy (kilowatthours) and power (kilowatts) lost in the operation of an electric system or transmission of power from the generation point of use. Operational losses occur principally as energy transformations from kilowatthours to waste heat in electric conductors and apparatus.

Macroeconomic A study generally having to do with activities observed and measured in terms of aggregates of firms and individuals, e.g., at the national level.

Marginal Cost The change in total costs associated with a unit change in quantity supplied (i.e., demand or energy).

Market Share The percentage of the marketplace captured by a particular producer or provider of services. Also refers to the percentage of homes or building types with installation of end-use services by fuel type.

Mean An average of a series of observations.

Measurement Errors Errors which occur in measuring the data values.

Megawatt (MW) One megawatt equals one million watts.

Megawatthour (MWh) One megawatthour equals one million watthours.

Mix Effect Combined effects of more than one factor.

Municipally-Owned Electric System An electric utility system owned and operated by a municipality usually, but not always, providing service within the boundaries of the municipality.

Not-for-Profit (NFP) When used in statistical tables to indicate class of ownership, it includes municipally-owned electric systems and federal and state public power projects.

Operating and Maintenance Expense A group of expenses applicable to day-to-day utility operations and maintenance of utility facilities.

Peak Demand The maximum amount of gas, water, or electricity consumed by a utility, its customers or by a group of customers during a specified period of time.

Peak Load The greatest demand which occurred during a specified period of time.

Peak Power Power that is generated or purchased by a utility to satisfy the peak demand.

Peaking Unit A generating unit available to assist in meeting that portion of total customer load which is above base and intermediate load.

Penetration This term is used to describe the market share of end-use technologies where electricity competes with other energy.

Power Flow The various paths over which power travels from the generator to the consumer. These paths are determined by laws of nature. Also called load flow.

Price Elasticity (Elasticity of Demand) The ratio of the percentage change in demand for a good to the percentage change in the price of that good. Demand is elastic when the absolute value of the ratio exceeds 1.0 and inelastic when it is less than 1.0. (See also *Elasticity)*

Process Model A model used to project industry growth and growth in energy use by projecting the growth of the factors used in the production process.

Productivity (Energy) Refers to the productivity of energy as a factor of production and indicates the level of economic value produced per unit of energy input. Energy productivity improvements occur when existing energy uses (e.g., lighting, heating, cooling and motor drive) can be obtained in more efficient ways and when new, energy-using technologies result in providing the same service levels with less energy.

Public Utility Regulatory Polices Act of 1978 (PURPA) Federal legislation designed to encourage conservation and alternative sources of electricity generation.

Rate Base The value established by a regulatory authority, upon which a utility is permitted to earn a specified rate of return.

Real An adjective that describes any monetary magnitude measured in constant prices of a single base year. Opposite of nominal. Economic data expressed in real dollars represent the changes in the value of the particular data after taking out the effect of changes in general price levels.

$$Reserve\ Margin = \frac{Rated\ Capacity - Peak\ Load}{Peak\ Load} X\ 100\%$$

Real Electric Prices A price that has been adjusted to remove the effects of changes in the purchasing power of the dollar. A real price usually reflects change in value relative to a base year.

Reliability The guarantee of system performance at all times and under all reasonable conditions to assure constancy, quality, adequacy and economy of electricity. It is also the assurance of a continuous supply of electricity for customers at the proper voltage and frequency.

Reserve The net accumulated balance reflecting reservations of Income or Retained Earnings to provide for a reduction in the value of an asset, for a contingent liability or loss, or for other special purposes.

Reserve Margin The percentage difference between rated capacity and peak load divided by peak load. (See also *Capacity Margin)*

Rural Electrification Administration (REA) A credit agency of the U.S. Department of Agriculture that assisted rural electric and telephone utilities in obtaining financing. REA was estasblished by Executive Order No. 7037 of May 11, 1935 and given statutory authority by the Rural Electricity Act of 1936. Abolished by Secretary of Agriculture memorandum 1010-1 (October 20, 1994). (See also *Rural Utilities Services*)

Rural Utilities Service (RUS) Established on October 20, 1994, by the Secretary of Agriculture as successor to the REA as mandated by the Department of Agriculture Reorganization Act of 1994 (Pub. L. 103-354, 108 Stat. 3178). RUS assigned responsibility for administering electric and telephone loan programs previously administered by the REA.

Sampling Error Error which occurs due to sampling. A sample is a subset of a population. Statistical properties of a sample are used to eliminate parameters pertaining to a population.

Saturation The supplying of a market with all the goods it will absorb. Used in reference to ownership of a particular good / service in the marketplace.

Service Area Territory in which a utility system is required or has the right to supply electric service to ultimate customers.

Space Heating The use of mechanical or electrical equipment to heat all or part of a building to at least 50 degrees Fahrenheit.

Short Run A period of time insufficient to permit any change in the inputs or technology of production. (See *Long Run*)

Standard Industrial Classification (SIC) A systematic methodology for classifying industrial activities. The first two digits define broad classes (i.e., 20 through 39 are manufacturing and 40s are generally commercial sector activities). The third and subsequent digits further define the activity (i.e., 3312 is blast furnace and steel production and 2819 is industrial gases).

Stochastic Random.

Summer Peak Demand The greatest load on an electric system during any prescribed demand interval in the summer (or cooling) season, usually between June 1 and September 30 (north of the equator).

Technology Curve A concept employed in REEMS and some other end-use models to capture the tradeoffs between efficiency and life cycle costs for all feasible technologies.

Transmission That portion of a utility plant used for the purpose of transmitting electric energy in bulk to other principal parts of the system or to other utility systems, or to expenses relating to the operation and maintenance of the transmission plant.

Unaffiliated Municipality A municipally-owned electric system that is not affiliated with the Indiana Municipal Power Agency (IMPA). (See also *Municipally-Owned Electric System*

Unaffiliated Rural Electric Membership Cooperative A rural electric membership cooperative that is not affiliated with Hoosier Energy Rural Electric Cooperative, Inc. (HEREC) or Wabash Valley Power Association (WVPA). (See also *Cooperative, Rural Electric Membership (REMC))*

Uncertainty Falling short of complete knowledge about an outcome or result. SUFG uses this term in context with forecast outcome.

Variance A measure of dispersion, spread or variability of a distribution, which will be large if the observations are distant from the mean or average and small if they are close to the mean.

Watt The electrical unit of real power or rate of doing work. The rate of energy transfer equivalent to one ampere flowing due to an electrical pressure of one volt at unity power factor. One watt is equivalent to approximately 1/746 horsepower or one joule per second.

Watthour The total amount of energy used in one hour by a device that requires one watt of power for continuous operation.

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LIST OF ACRONYMS

Btu	British Thermal Unit
CEMR	Center for Econometric Model Research
CC	Combined Cycle
CT	Combustion Turbine
CEDMS	Commercial Energy Demand Modeling System
DSM	Demand-Side Management
DOE	Department of Energy
EMI	Econometric Model of Indiana
EPRI	Electric Power Research Institute
EIA	Energy Information Administration
EPACT	Energy Policy Act of 1992
GAMS	General Algebraic Modeling System
GWh	Gigawatthours
GDP	Gross Domestic Product
GSP	Gross State Product
HVAC	Heating, Ventilation and Air Conditioning
HELM	Hourly Electric Load Model
HEREC	Hoosier Energy Rural Electric Cooperative, Inc.
IBRC	Indiana Business Research Center
INDEPTH	Industrial End-Use Planning Methodology
I&M	Indiana Michigan Power Company
IMPA	Indiana Municipal Power Agency
IRP-Manager	Integrated Resource Planning Manager
ISAW	Indiana State Agency Workgroup
IUPUI	Indiana University Purdue University, Indianapolis
IURC	Indiana Utility Regulatory Commission
IPL	Indianapolis Power & Light Company
INFORM	Industrial End-Use Forecast Model
IRP	Integrated Resource Plan
IOU	Investor-Owned Utility
kW	Kilowatt
kWh	Kilowatthours
LMSTM	Load Management Strategy Testing Model
MW	Megawatt
MWh	Megawatthours
mmBtu	Million British Thermal Unit
NO_x	Nitrogen Oxides
NIPSCO	Northern Indiana Public Service Company
NFP	Not-for-Profit
ORNL	Oak Ridge National Labs
O&M	Operation and Maintenance
PSI Energy	PSI Energy, Inc.
PC	Pulverized Coal-Fired
REEMS	Residential End-Use Energy Modeling System
REMC	Rural Electric Membership Cooperative
RTO	Regional Transmission Organization
RUS	Rural Utilities Service
SIGECO	Southern Indiana Gas & Electric Com pany
SIC	Standard Industrial Classification
SUFG	State Utility Forecasting Group
SO_2	Sulfur Dioxide
TEEMS	Technology-Based End-Use Energy Modeling System
TELPLAN	Total Electric Planning Model
WVPA	Wabash Valley Power Association