Indiana Electricity Projections:
The 2011 Forecast

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Foreword

This report presents the 2011 projections of future electricity requirements for the state of Indiana for the period 2010-2029. 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 thirteenth 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."*

This report provides projections from a statewide perspective. Individual utilities will experience different levels of growth due to a variety of economic, geographic, and demographic factors.

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:

http://www.purdue.edu/dp/energy/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. Also, the authors would like to gratefully acknowledge the Indiana Utility Regulatory Commission for its support, 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

Forecast Summary

Overview

In this report, the State Utility Forecasting Group (SUFG) provides its thirteenth set of projections of future electricity usage, peak demand, prices and resource requirements. This forecast contains generally lower projections of electricity sales and peak demand, especially in the residential and commercial sectors, than were found in previous SUFG forecasts. Consequently, fewer future resources are expected to be needed, with no significant additional resources expected to be needed until 2015 unless additional plant retirements occur before then.

This forecast projects electricity usage to grow at a rate of 1.30 percent per year over the 20 years of the forecast. This growth rate is considerably lower than Indiana has historically experienced and somewhat lower than the 2009 SUFG projections. The lower growth in electricity usage is primarily due to increasing efficiency; that is, using less electrical energy to operate homes and businesses. Efficiency gains are projected to occur from three sources: higher projected electricity prices making investments in higher efficiency equipment more cost-effective, utility-sponsored conservation efforts, and stricter federal energy efficiency standards. Peak electricity demand is projected to grow at an average rate of 1.28 percent annually. This corresponds to about 275 megawatts (MW) of increased peak demand per year.

The 2011 forecast predicts Indiana electricity prices to increase by 20 percent in real (inflation adjusted) terms between 2010 and 2017 and then level off through the remainder of the forecast period. The price increase is caused by three factors; costs associated with ongoing new plant construction, costs associated with extending the life of existing generating facilities, and costs associated with meeting environmental rules. It should be noted that this report includes only the costs associated with regulations in place at the time the forecast was prepared. Additional proposed and expected regulations would likely cause additional expenses as plants are retrofitted or retired and replaced. In the fall of 2011, SUFG intends to release a study of the expected impacts of such regulations.

As in the previous two forecasts, these projections indicate a relatively balanced need for the three types of resources modeled: baseload, cycling (also referred to as intermediate) and peaking. Peaking resources are characterized by relatively low construction costs, but high operating costs. They are intended to be operated only during periods of high electricity usage. Baseload generators, which are intended to be used even during periods of low demand, have relatively high construction costs but low operating costs. Cycling resources have construction and operating cost characteristics between those of peaking and baseload resources. This forecast identifies a need for 770 MW of peaking, 640 MW of cycling, and 1,190 MW of baseload resources by 2020. These requirements are roughly two-thirds those identified in the 2009 forecast.

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.

Outline of the Report

The current forecast continues to respond to SUFG's legislative mandate to forecast electricity demand. It includes projections of electric 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, including changes made from previous forecasts. 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:

http://www.purdue.edu/dp/energy/SUFG/

Chapter 3 presents the projections of statewide electricity demand, resource requirements, and price, while Chapter 4 describes the data inputs and Chapters 5 through 7 present integrated projections 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 provides an overview of potential environmental regulations. Finally, an Appendix depicts the data sources used to produce the forecast and provides historical and forecast 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.

Beginning with the 2009 forecast, SUFG made a slight modification to the methodology used in determining future resource requirements. For the 1999-2007 forecasts, SUFG determined required resources according to a target statewide 15 percent reserve margin.[1] Forecasts prior to 1999 used a 20 percent statewide reserve margin. These reserve margins were essentially rules-of-thumb, based on industry observations. Recently, the regional transmission organizations that encompass Indiana utilities have determined planning reserve requirements for their members. In 2009 SUFG began using reserve margins that reflect the planning reserve requirements of the utilities' regional transmission organizations to determine the reserve requirements in this forecast. Applying the individual reserve requirements and adjusting for peak load diversity among the utilities provides a statewide reserve requirement of approximately 15.8 percent. This represents a slightly lower reserve margin than the 16.3 percent figure used in the 2009 forecast due to changing regional transmission organization (RTO) requirements. It should be noted that the change from a 15 percent to a 16.3 or 15.8 percent target reserve margin in the SUFG forecasts does not represent an increase in reserves (and hence, an increase in costs) due to the utilities' memberships in the regional transmission organizations. Rather, it represents a change by SUFG to a target reserve margin that is based on a more rigorous analysis.

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 the Center for Econometric Model Research (CEMR) at Indiana University. SUFG used CEMR's February 2011 projections for its base scenario. 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. The CEMR Indiana projections are based on a national employment projection of 1.25 percent growth per year over the forecast period. Indiana total employment is projected to grow at an average annual rate of 1.21 percent.

Other key economic projections are:

- Real personal income (a residential sector model driver) is expected to grow at a 2.02 percent annual rate.

[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 15.8 percent reserve margin is equivalent to a 13.6 percent capacity margin.
Capacity Margin = [(Capacity-Peak Demand)/Capacity]
Reserve Margin = [(Capacity-Peak Demand)/Peak Demand]

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

- Non-manufacturing employment (the commercial sector model driver) is expected to average a 1.31 percent annual growth rate over the forecast horizon.
- Manufacturing gross state product (GSP) (the primary industrial sector model driver) is expected to rise at a 3.44 percent annual rate as gains in productivity outpace slight gains 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 0.49 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 1.00 percent over the forecast period.

Fossil Fuel Price Projections

SUFG's current assumptions are based on the April 2011 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: Natural gas price projections exhibit a significant decrease in 2009 coming off of the high prices of 2008. Prices are then projected to remain relatively constant through 2015, with a gradual increase following for the remainder of the forecast horizon.

Utility Price of Coal: Coal prices are relatively unchanged in real terms throughout the entire forecast horizon as growth in demand is offset by improvements in mining productivity.

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 in MW is shown in Figure 1-2. The annual growth rate for electricity requirements in this forecast is 1.30 percent, while the growth rate for peak demand is 1.28 percent. The growth rates in the previous forecast for electricity requirements and peak demand were 1.55 and 1.61 percent, respectively.

The growth within sectors varies considerably with higher growth in the industrial sector and lower growth in the residential and commercial sectors (see Table 1-1). See Chapters 5 through 7 for more detail on the sectoral forecasts.

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 275 MW.

Table 1-1. Annual Electricity Sales Growth (Percent) by Sector (Current vs. 2009 Projections)

Sector	Current (2010-2029)	2009 (2008-2027)
Residential	0.71	1.75
Commercial	0.89	1.18
Industrial	2.11	1.63
Total	1.30	1.55

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 15.8 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.

[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 Forecasts)

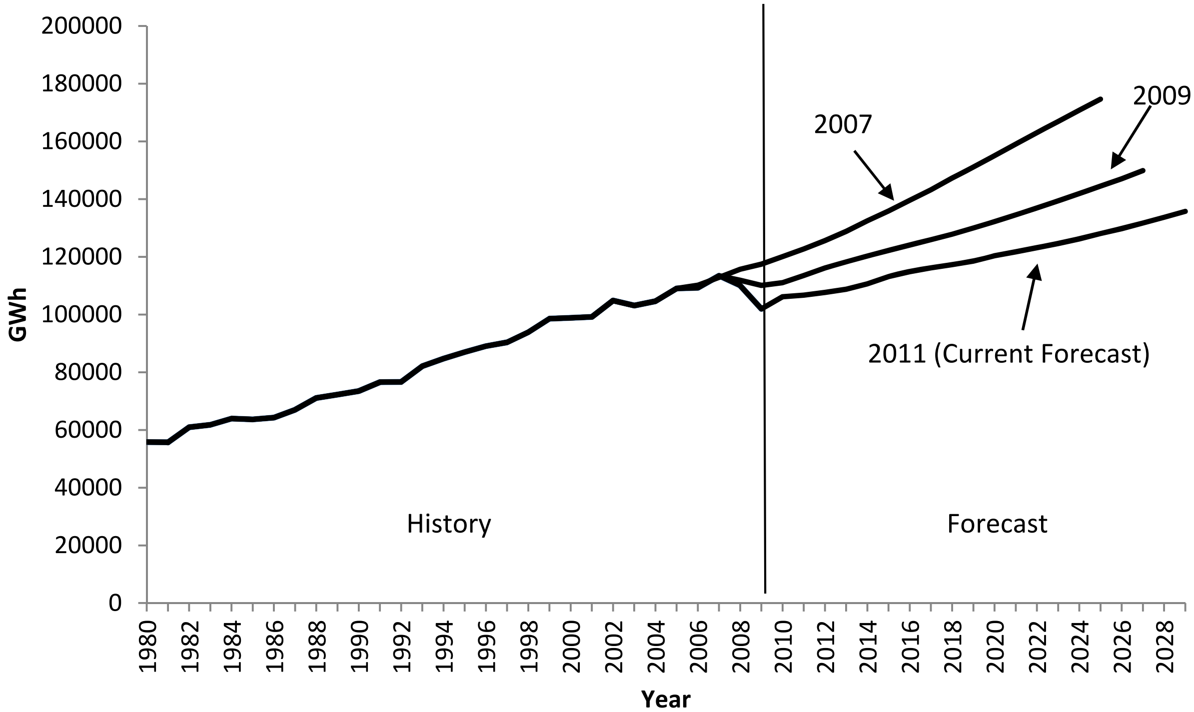
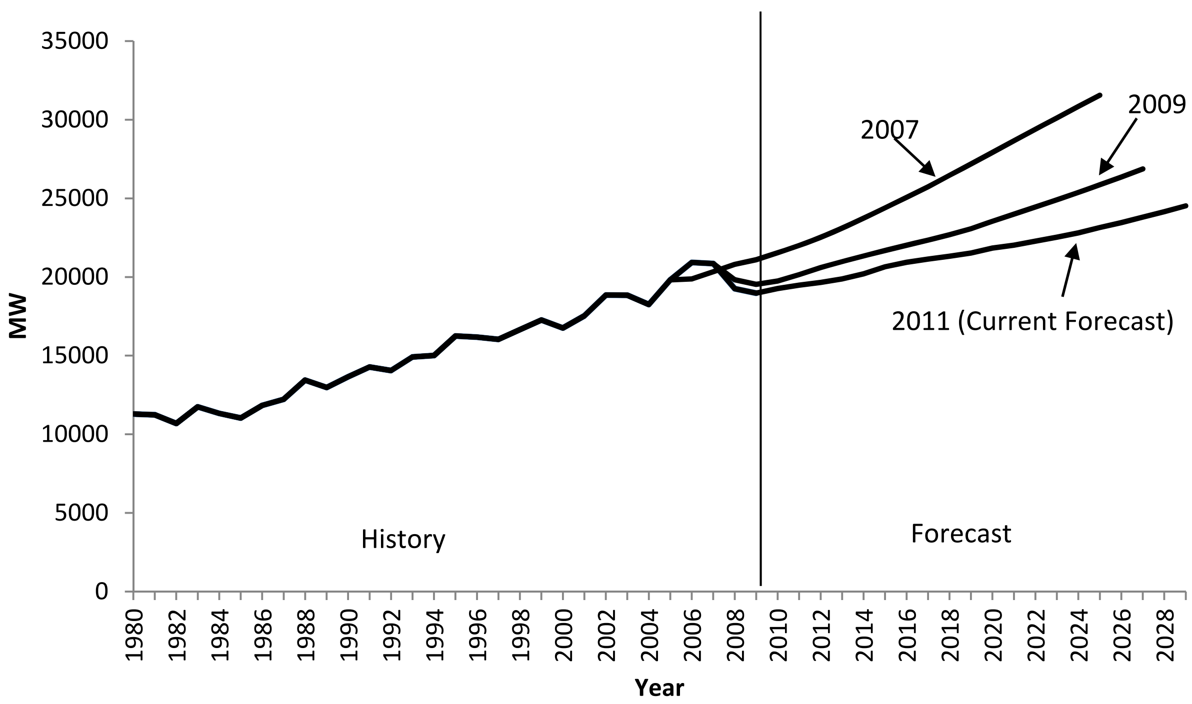


Figure 1-2. Indiana Peak Demand Requirements in MW (Historical, Current, and Previous Forecasts)



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 240 MW at the beginning of the forecast period and by over 800 MW at the end of the forecast. DSM projections were estimated by SUFG based on rules established in December 2009 by the Indiana Utility Regulatory Commission (IURC).

These DSM projections do not include the reductions in peak demand due to interruptible load contracts with large customers. Interruptible loads are projected to increase from 770 MW to about 900 MW over the forecast horizon. See Chapter 4 for additional information about DSM and interruptible loads.

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, de-ratings due to pollution control retrofits and net changes in firm out-of-state purchases and sales. Due to the timing and uncertainty over Duke Energy's shutdown of three Wabash River units, SUFG has not removed those units from the existing mix of generators.[4] 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 15.8 percent reserve margin.

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, nearly 1,500 MW of additional resources are required. The net change in generation includes the retirement of units as reported in the utilities' 2009 Integrated Resource Plan (IRP) filings. Over the second half of the forecast period, an additional 3,900 MW of resources are required to maintain target reserves. If Duke Energy retires the affected Wabash River units, additional resources of approximately 250 MW will be required.

Due to data availability restrictions at the time that SUFG prepared the modeling system to produce this forecast, the most current year with a complete set of actual historical data is 2009. Therefore, 2010 and 2011 numbers represent projections. The resource requirements identified in Table 1-2 for 2010 and 2011 were most likely met by a combination of short-term purchases and longer-term purchases of which SUFG was not aware at the time the forecast was prepared.

Equilibrium Price and Energy Impact

SUFG's base scenario equilibrium real electricity price trajectory is shown in Figure 1-4. Real prices are projected to increase significantly through 2016 and then remain fairly constant for the remainder of the forecast period. The change in prices early in the forecast horizon is significant, thus the electricity requirements projection for this portion of the forecast period is affected.

SUFG's equilibrium price projections for two previous forecasts are also shown in Figure 1-4. The price projection labeled "2009" is the base from SUFG's 2009 forecast and the price projection labeled "2007" is the base case projection contained in SUFG's 2007 forecast. For the prior price forecasts, SUFG rescaled the original price projections to 2009 dollars (from 2005 dollars for the 2007 projection, and from 2007 dollars for the 2009 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

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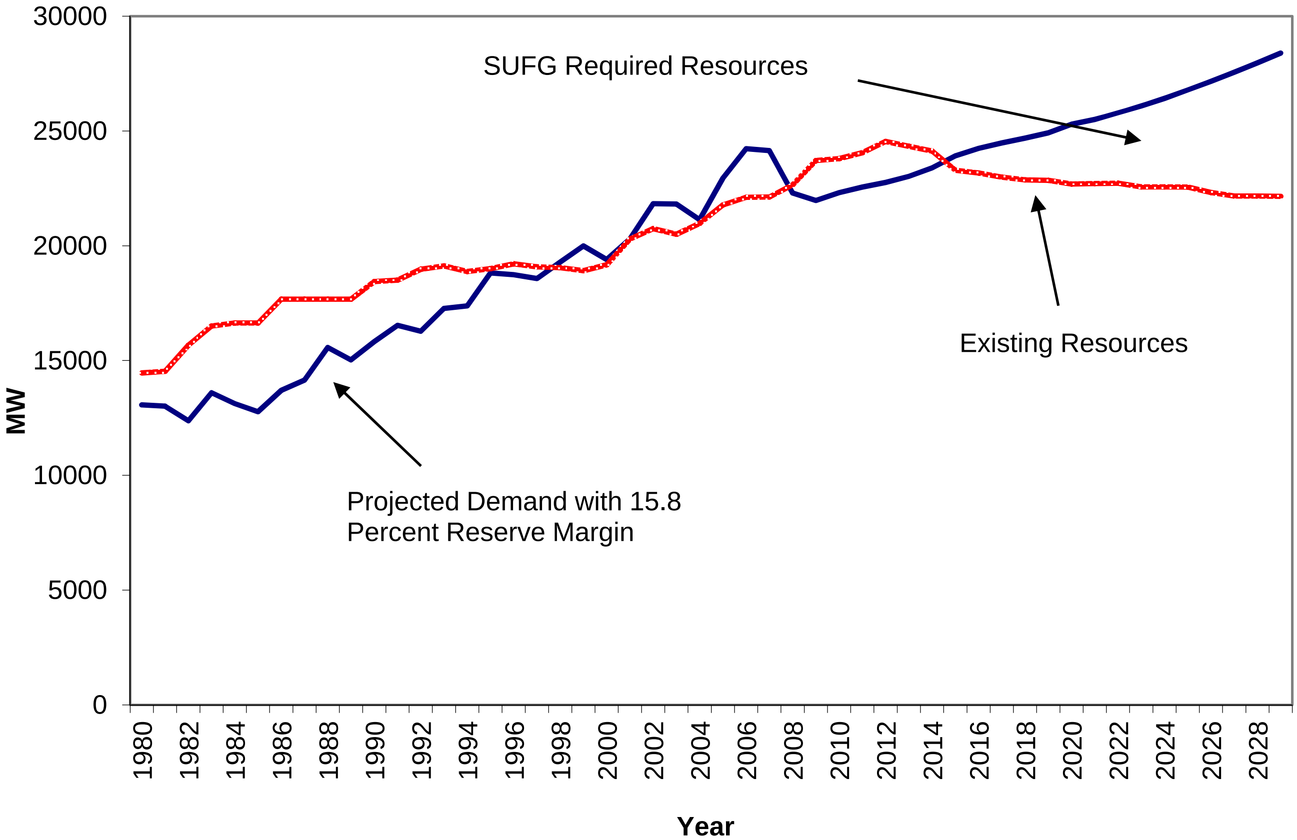
[4] Duke Energy shut down its Wabash River units 2, 3, and 5 in September 2009 as a result of a U.S. District Court ruling regarding alleged violations of the Clean Air Act. At the time this forecast was prepared, the status of any appeal of that ruling was unknown.

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



The price increase through 2016 in Figure 1-4 is caused by three factors; costs associated with ongoing new plant construction, costs associated with extending the life of existing generating facilities, and costs associated with meeting environmental rules. It should be noted that costs associated with environmental rules that are in place at the time the forecast was prepared are included, while proposed and potential future rules are not. Thus, the costs associated with meeting the first phase of the Clean Air Interstate Rule (CAIR) are included. The replacement for CAIR, the Cross-State Air Pollution Rule (CSAPR) was finalized after the model runs for this report were completed, thus CSAPR is not modeled in its final form. Other non-finalized rules, such as the Mercury and Air Toxics Standards (MATS), which was proposed in March 2011, and rules affecting greenhouse gas emissions, cooling water, and coal ash disposal are not included. SUFG will produce a separate report that specifically addresses the impact of the various proposed and potential rules. This report is expected to be completed in the fall of 2011. See Chapter 8 for an overview of potential regulations.

Low and High Scenarios

SUFG has constructed alternative low and high economic 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. The annual growth rates for the base, low and high scenarios are 1.30, 0.98, and 1.64, respectively. These differences are due to economic 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.

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

	Uncontrolled Peak Demand[1]	Interruptible	Net Peak Demand[2]	Existing/ Approved Capacity[3]	Incremental Change in Capacity[4]	Projected Additional Resource Requirements[5]				Total Resources[6]	Reserve Margin[7] (percent)
						Peaking	Cycling	Baseload	Total		
2009				23,719							
2010	20,047	778	19,269	23,800	81	0	0	0	0	23800	17
2011	20,251	770	19,481	24,055	255	0	0	0	0	24055	21
2012	20,437	783	19,654	24,543	488	0	0	0	0	24543	24
2013	20,676	795	19,881	24,340	-204	100	20	0	120	24460	23
2014	21,008	805	20,203	24,128	-212	220	30	70	320	24448	25
2015	21,468	818	20,650	23,292	-836	310	90	330	730	24022	23
2016	21,767	832	20,935	23,171	-121	380	160	520	1060	24231	21
2017	21,987	846	21,141	22,991	-180	480	310	700	1490	24481	16
2018	22,180	861	21,319	22,873	-118	520	510	780	1810	24683	16
2019	22,396	876	21,520	22,851	-23	570	550	920	2040	24891	16
2020	22,730	889	21,841	22,696	-155	770	640	1190	2600	25296	16
2021	22,915	889	22,026	22,715	20	800	680	1300	2780	25495	16
2022	23,166	889	22,277	22,725	10	860	740	1470	3070	25795	16
2023	23,419	891	22,528	22,565	-160	920	920	1670	3510	26075	16
2024	23,702	893	22,810	22,565	0	990	1010	1830	3830	26395	16
2025	24,035	895	23,140	22,558	-7	1030	1090	2110	4230	26788	16
2026	24,350	896	23,454	22,322	-236	1060	1330	2440	4830	27152	16
2027	24,696	898	23,798	22,173	-150	1270	1400	2690	5360	27533	16
2028	25,052	900	24,152	22,168	-4	1350	1470	2940	5760	27928	16
2029	25,423	902	24,521	22,153	-15	1490	1590	3160	6240	28393	16

1 Uncontrolled peak demand is the peak demand without any interruptible loads being called upon.

2 Net peak demand is the peak demand after 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 additional resource requirements is the cumulative amount of additional resources needed to meet future requirements.

6 Total resource requirements are the total statewide resources required including existing/approved capacity and projected additional resource requirements.

7 Resources may be required by individual utilities even if the state as a whole meets or exceeds the statewide reserve margin. Individual utility reserve margins are not allowed to fall below 6 percent.

Figure 1-4. Indiana Real Price Projections in cents/kWh (2009 Dollars) (Historical, Current and Previous Forecasts)

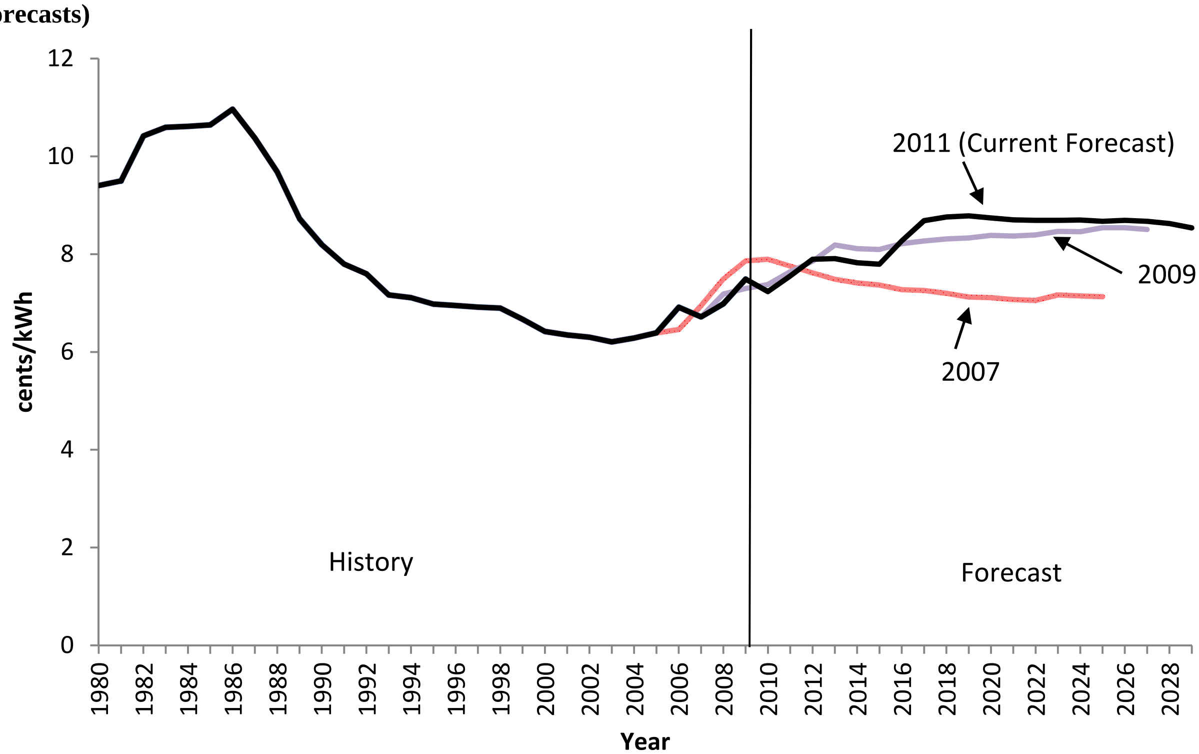
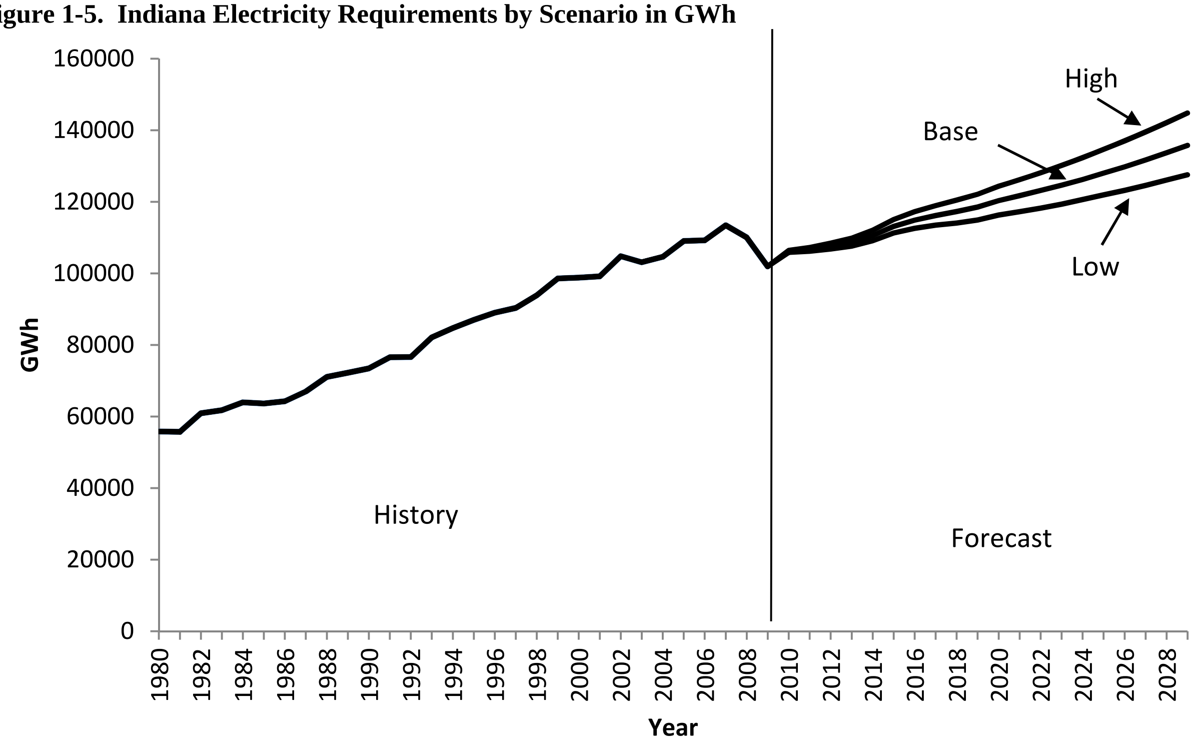


Figure 1-5. Indiana Electricity Requirements by Scenario in GWh



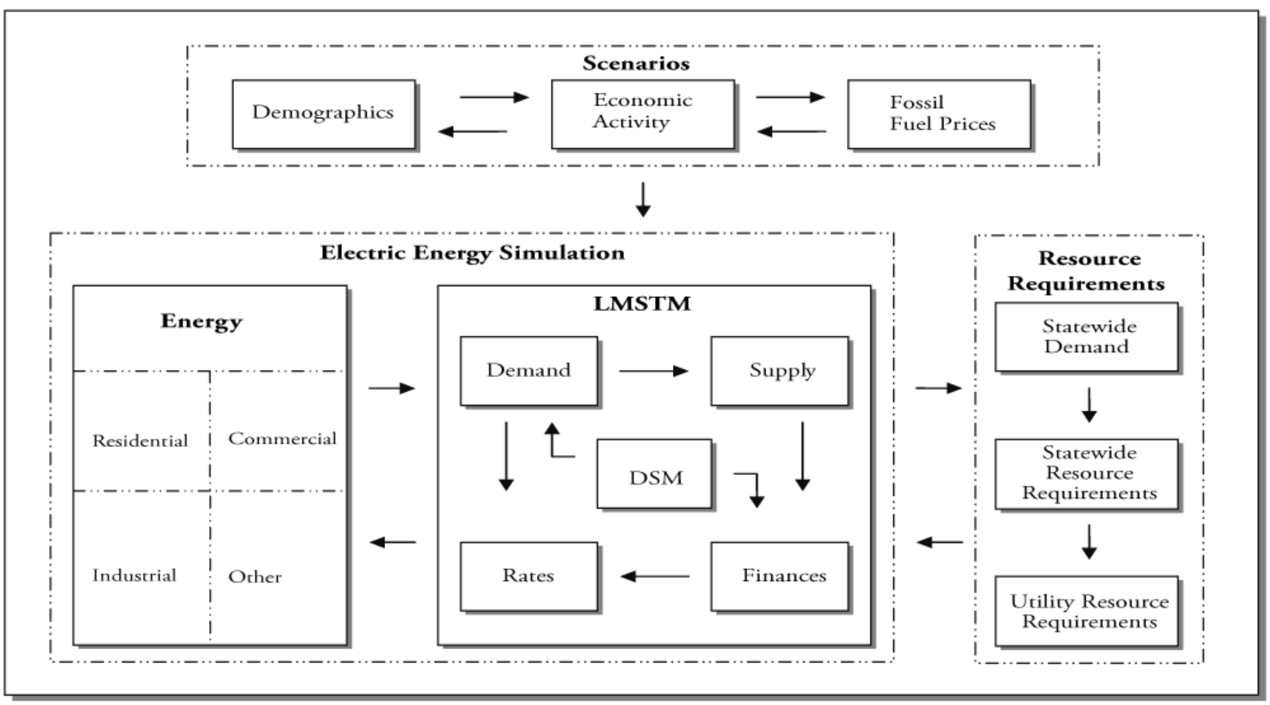
Chapter 2

Overview of SUFG Electricity Modeling System

Regulated Modeling System

SUFG's integrated electricity modeling system projects electricity demand, supply and price for each electric utility in the state under Indiana's present regulatory structure. 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 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.

Figure 2-1. SUFG's Regulated Modeling System



Scenarios

SUFG's electricity projections are based 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 growth scenarios capture much of the uncertainty associated with economic growth, fossil fuel prices and statistical error in the model structure.

Electric Utility Simulation

The electric utility simulation portion of the modeling system develops projections for each of the five investor-owned utilities (IOUs): Duke Energy Indiana, Indiana Michigan Power Company, Indianapolis Power & Light Company, Northern Indiana Public Service Company, and Southern Indiana Gas & Electric Company. In addition, projections are developed for the three not-for-profit (NFP) utilities: Hoosier Energy Rural Electric Cooperative, Indiana Municipal Power Agency, and Wabash Valley Power Association.

Utility-specific projections of sectoral energy use and prices are developed for each of the three scenarios. These projections are based on projections of demographics, economic activity and fossil fuel prices that are developed outside the modeling system. They are also based on projections of supply additions for the utilities that are developed within the framework of the modeling system.

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. For this forecast, SUFG is using end-use models for the residential and commercial sectors and an econometric model for the industrial sector. SUFG has switched to the residential end-use model for this forecast after previously using an econometric model. The change was made for a number of reasons, including the enhanced ability of the end-use model to capture the impacts of federally mandated lighting efficiency standards. Additional information regarding SUFG's energy models for the residential, commercial and industrial sectors can be found in chapters five, six and seven, respectively.

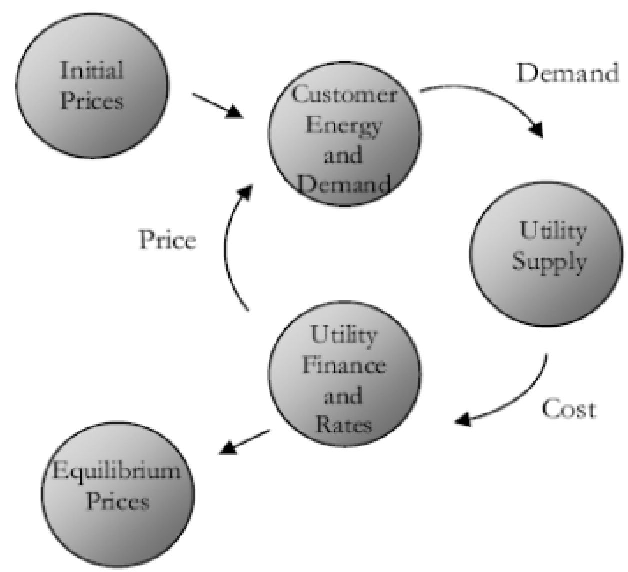
Load Management Strategy Testing Model

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 demand side management or DSM), system operations and customer rates.

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 iterative process ends. Otherwise, the modeling system continues to cycle through the submodels until equilibrium is attained as is illustrated in Figure 2-2.

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



Resource Requirements

Beginning with the 2009 forecast, SUFG has made a slight modification to the methodology used in determining future resource requirements. For the 1999-2007 forecasts, SUFG determined required resources according to a target statewide 15 percent reserve margin. Forecasts prior to 1999 used a 20 percent statewide reserve margin. These reserve margins were essentially rules-of-thumb, based on industry observations. Recently, the regional transmission organizations that encompass Indiana utilities have determined planning reserve requirements for their members. Starting with the 2009 forecast, SUFG has used individual utility reserve margins that reflect the planning reserve requirements of the utility's RTO to determine the reserve requirements in this forecast. Applying the individual reserve requirements and adjusting for peak load diversity[1] among the utilities provides a statewide reserve requirement of approximately 15.8 percent. This represents a slightly lower reserve margin than the 16.3 percent figure used in the 2009 forecast due to changing RTO requirements. It should be noted that the change from a 15 percent to a 16.3 or 15.8 percent target in the SUFG forecasts does not represent an increase in reserves (and hence, an increase in costs) due to the utilities' memberships in the RTOs. Rather, it represents a change by SUFG to a target that is based on a more rigorous analysis.

The process used to determine resource requirements is illustrated in the flowchart 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. The additional resources required are determined for each year by comparing the peak demand with a 15.8 percent reserve margin to the existing capacity. The existing capacity has been adjusted for retirements, utility purchases and sales, and new construction projects that have been approved by the Indiana Utility Regulatory Commission (IURC).

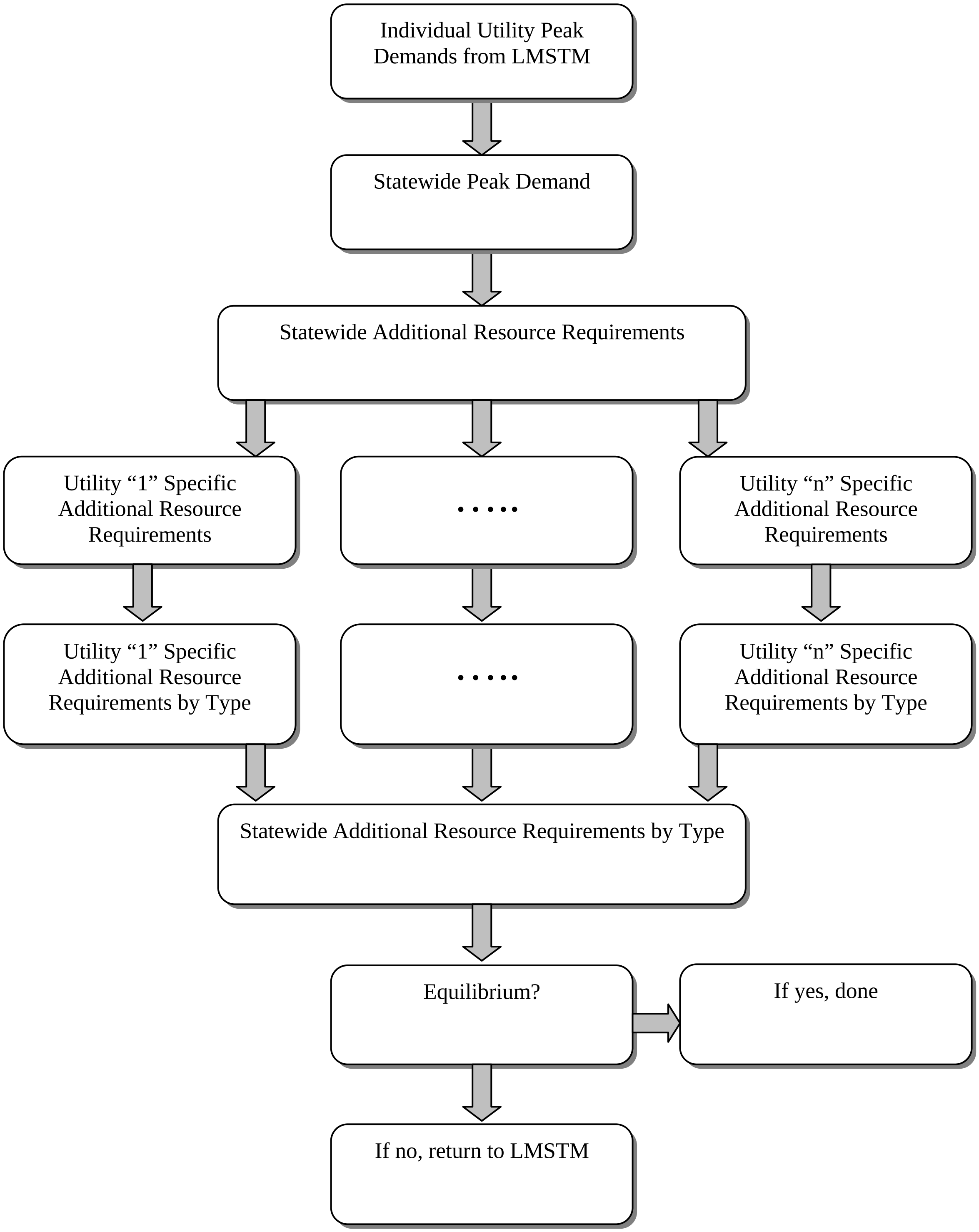
The required resources are then assigned to the individual utilities with the lowest reserve margins, so that all utilities have similar reserve margins. Even if the state's reserve margin meets the 15.8 percent target, resources will be assigned to an individual utility if necessary to bring the utility's reserve margin up to 6 percent. These utility specific additional resource requirements are then assigned to one of the three types. This is accomplished by comparing the utility's demand, which is divided into the three types using actual historical annual load shapes, 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 equilibrium is reached where resource requirements do not change from one iteration to the next.

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.

[1] Load diversity occurs because the peak demands for all utilities do not occur at the same time. SUFG estimates the amount of load diversity by analyzing the actual historical load patterns of the various utilities in the state.

Figure 2-3. Resource Requirements Flowchart



Chapter 3

Indiana Projections of Electricity Requirements, Peak Demand, Resource Needs and Prices

Introduction

This chapter presents the forecast of future electricity requirements and peak demand, including 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 macroeconomic assumptions that is considered "most likely," i.e., each assumption has an equal probability of being lower or higher. Additionally, SUFG included low and high growth macroeconomic 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 Tables 3-1 and 3-2 and Figures 3-1 and 3-2, SUFG's current base scenario projection indicates annual growth of 1.30 percent for electricity requirements and 1.28 percent for peak demand. As shown in Table 3-3, the growth rate for electricity sales in this forecast is about 0.25 percent lower than the 2009 forecast. As one would expect, the current economic situation and the projected future path of the economy have a dramatic effect on the electricity sales forecast. The growth within sectors varies considerably with lower growth in the residential and commercial sectors offsetting higher growth in the industrial sector, but the forecast growth for all sectors is only moderately below the forecast in 2009. See Chapters 5, 6, and 7 for discussions of the forecast growth in the residential, commercial, and industrial sectors.

A comparison of the forecast trajectory of electricity requirements between the current and previous forecast shows that the current forecast starts out below the previous forecast and that the gap between the projections widens over the forecast horizon. The drop in electricity requirements in 2008 and 2009 is due to a combination of the economic recession and milder than normal weather, both of which suppress electricity usage. This general pattern is followed in all three sectors.

The growth in peak demand is similarly lower than that projected in 2009 and follows the same pattern that is observed for the total energy requirements. Forecast peak demand growth is slightly lower than that of electricity requirements (1.28 versus 1.31 percent) because lower energy growth in the residential and commercial sectors, both of which have weather sensitive heating and cooling load, tends to affect peak demand more than the industrial sector load. Another measure of peak demand growth can be obtained by considering the average year to year peak MW load change. In Figure 3-2, the annual increase is 275 MW compared to about 350 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 generic resources are added as necessary to maintain a 15.8 percent reserve margin (see Chapter 2 for discussions of the future resource allocation methodology and the target 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 obtained at least cost.

Demand-Side Resources

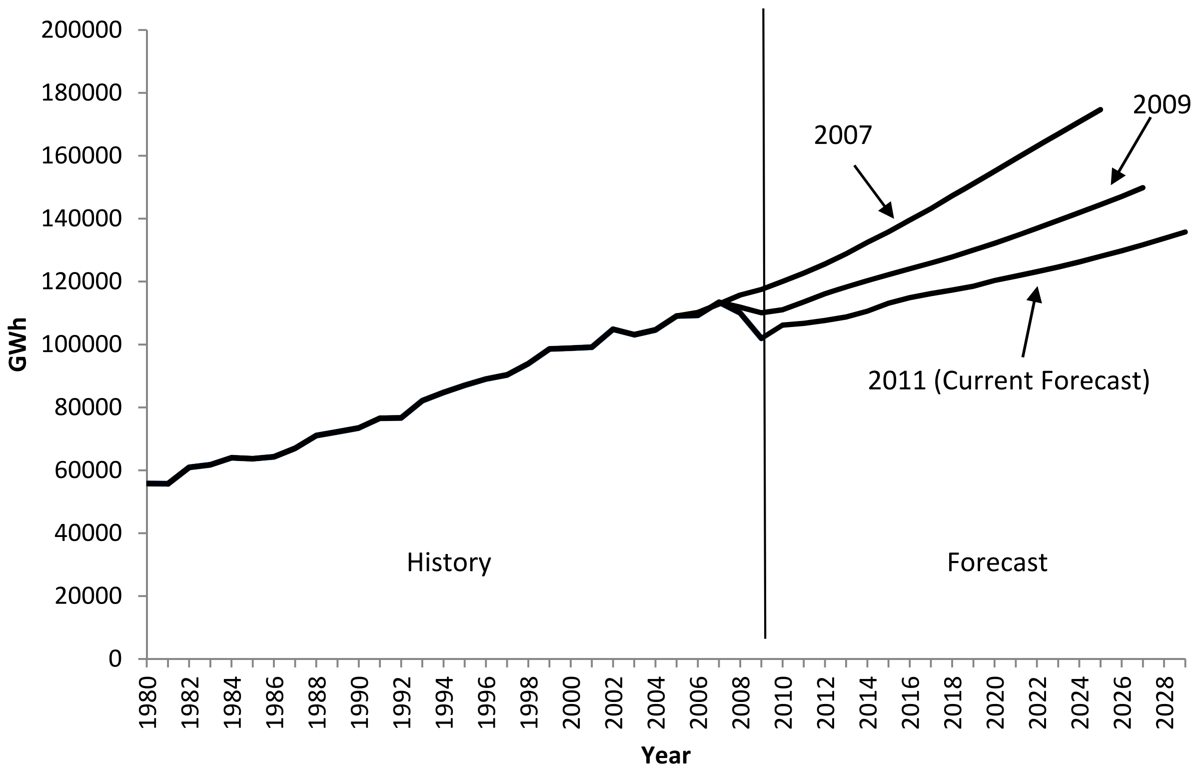
The current projection includes the energy and demand impacts of existing or planned utility-sponsored DSM programs. Incremental DSM programs, which include new programs and the expansion of existing programs, are projected to reduce peak demand by approximately 240 MW at the beginning of the forecast period and by over 800 MW at the end of the forecast. DSM projections reflect the estimated impact of the IURC's DSM order of December 2009.

In addition to DSM, peak demand projections are reduced due to interruptible load contracts with large customers. Interruptible loads are projected to increase from 770 MW to about 900 MW over the forecast horizon. See Chapter 4 for additional information about DSM and interruptible loads.

Table 3-1. Indiana Electricity Requirements Average Compound Growth Rates (Percent)

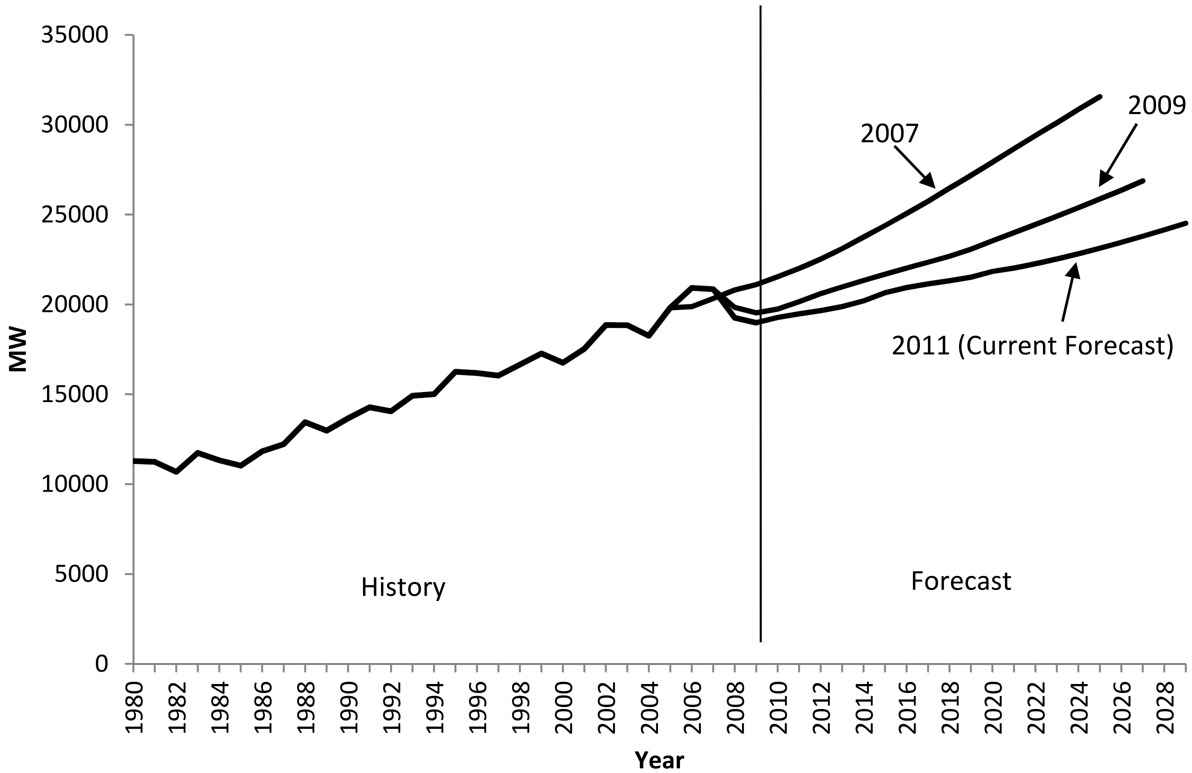
Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2007	2.46	2006-2025
2009	1.55	2008-2027
2011	1.30	2010-2029

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



Note: See the Appendix to this report for historical and projected values.

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



Note: See the Appendix to this report for historical and projected values.

Table 3-2. Indiana Peak Demand Requirements Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2007	2.46	2006-2025
2009	1.61	2008-2027
2011	1.28	2010-2029

Table 3-3. Annual Electricity Sales Growth (Percent) by Sector (Current vs. 2009 Projections)

Sector	Current (2010-2029)	2009 (2008-2027)
Residential	0.71	1.75
Commercial	0.89	1.18
Industrial	2.11	1.63
Total	1.31	1.55

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, and net changes in firm out-of-state purchases and sales. Due to the timing and uncertainty over Duke Energy's shutdown of three Wabash River units, SUFG has not removed those units from the existing mix of generators. SUFG does not attempt to forecast long-term out-of-state contracts other than those currently in place. Generic firm wholesale purchases are added at prices that reflect SUFG estimates of long-run average costs for these purchases as necessary during the forecast period to maintain a 15.8 percent statewide reserve margin. This level of statewide reserves is derived from individual utility reserve margins that reflect the planning reserve requirements of the utility's regional transmission organization. Note that the reserve margin incorporated in this forecast is slightly lower than the 16.3 percent figure used in 2009. This is due to revisions in planning reserve requirements by the regional transmission organizations.

Three types of generic firm wholesale purchases are included:

1. peaking purchases;
2. cycling purchases; and
3. 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), and both cycling and baseload units to be gas-fired combined cycle (CC) plants. This represents a change from previous forecasts, which used pulverized coal (PC) units as the basis for baseload purchases. This change was made because the most recent fuel price projections and capital cost estimates indicate that CC units would be a lower cost option than PC units. Purchase price projections for each of these purchase types are set to recover the long-run cost of generating electricity from each unit. Continued increases in construction costs have resulted in significantly higher purchase price projections than were used in the previous SUFG forecast.

Table 3-4 and Figure 3-3 show the statewide resource plan for the SUFG base scenario. This forecast identifies no need for peaking, cycling or baseload resources required before 2015. These requirements are lower than those identified in the 2009 forecast because of a number of factors, including lower peak demand projections (due to economic factors and increased energy efficiency), a lower target reserve margin, and new long-term power purchases of wind generated power. By 2020, a total of 2,600 MW of resource additions are required, of which 770 MW is peaking, 640 MW is cycling, and 1,190 MW is baseload. About 4,200 MW of resource additions are required by 2025, and approximately 6,200 MW by 2029. The net change in generation includes the retirement of units as reported in the utilities' 2009 IRP filings, changes in firm purchases and sales, and the addition of approved new capacity. If Duke Energy retires the affected Wabash River units, additional resources of approximately 250 MW will be required.

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.

Due to data availability restrictions at the time that SUFG prepared the modeling system to produce this forecast, the most current year with a complete set of actual historical data is 2009. Therefore, 2010 and 2011 numbers do not include short term purchases and any longer term purchases of which SUFG was not aware at the time the forecast was prepared.

[1] Duke Energy shut down its Wabash River units 2, 3, and 5 in September 2009 as a result of a U.S. District Court ruling regarding alleged violations of the Clean Air Act. At the time this forecast was prepared, the future status of those generating units was unknown.

Table 3-4. Indiana Resource Plan in MW (SUFG Base)

	Uncontrolled Peak Demand[1]	Interruptible	Net Peak Demand[2]	Existing/ Approved Capacity[3]	Incremental Change in Capacity[4]	Projected Additional Resource Requirements[5]				Total Resources[6]	Reserve Margin[7] (percent)
						Peaking	Cycling	Baseload	Total		
2009				23,719							
2010	20,047	778	19,269	23,800	81	0	0	0	0	23800	17
2011	20,251	770	19,481	24,055	255	0	0	0	0	24055	21
2012	20,437	783	19,654	24,543	488	0	0	0	0	24543	24
2013	20,676	795	19,881	24,340	-204	100	20	0	120	24460	23
2014	21,008	805	20,203	24,128	-212	220	30	70	320	24448	25
2015	21,468	818	20,650	23,292	-836	310	90	330	730	24022	23
2016	21,767	832	20,935	23,171	-121	380	160	520	1060	24231	21
2017	21,987	846	21,141	22,991	-180	480	310	700	1490	24481	16
2018	22,180	861	21,319	22,873	-118	520	510	780	1810	24683	16
2019	22,396	876	21,520	22,851	-23	570	550	920	2040	24891	16
2020	22,730	889	21,841	22,696	-155	770	640	1190	2600	25296	16
2021	22,915	889	22,026	22,715	20	800	680	1300	2780	25495	16
2022	23,166	889	22,277	22,725	10	860	740	1470	3070	25795	16
2023	23,419	891	22,528	22,565	-160	920	920	1670	3510	26075	16
2024	23,702	893	22,810	22,565	0	990	1010	1830	3830	26395	16
2025	24,035	895	23,140	22,558	-7	1030	1090	2110	4230	26788	16
2026	24,350	896	23,454	22,322	-236	1060	1330	2440	4830	27152	16
2027	24,696	898	23,798	22,173	-150	1270	1400	2690	5360	27533	16
2028	25,052	900	24,152	22,168	-4	1350	1470	2940	5760	27928	16
2029	25,423	902	24,521	22,153	-15	1490	1590	3160	6240	28393	16

1 Uncontrolled peak demand is the peak demand without any interruptible loads being called upon.

2 Net peak demand is the peak demand after interruptible loads are taken into account.

3 Existing/approved capacity includes installed capacity plus approved new capacity plus firm purchases minus firm sales.

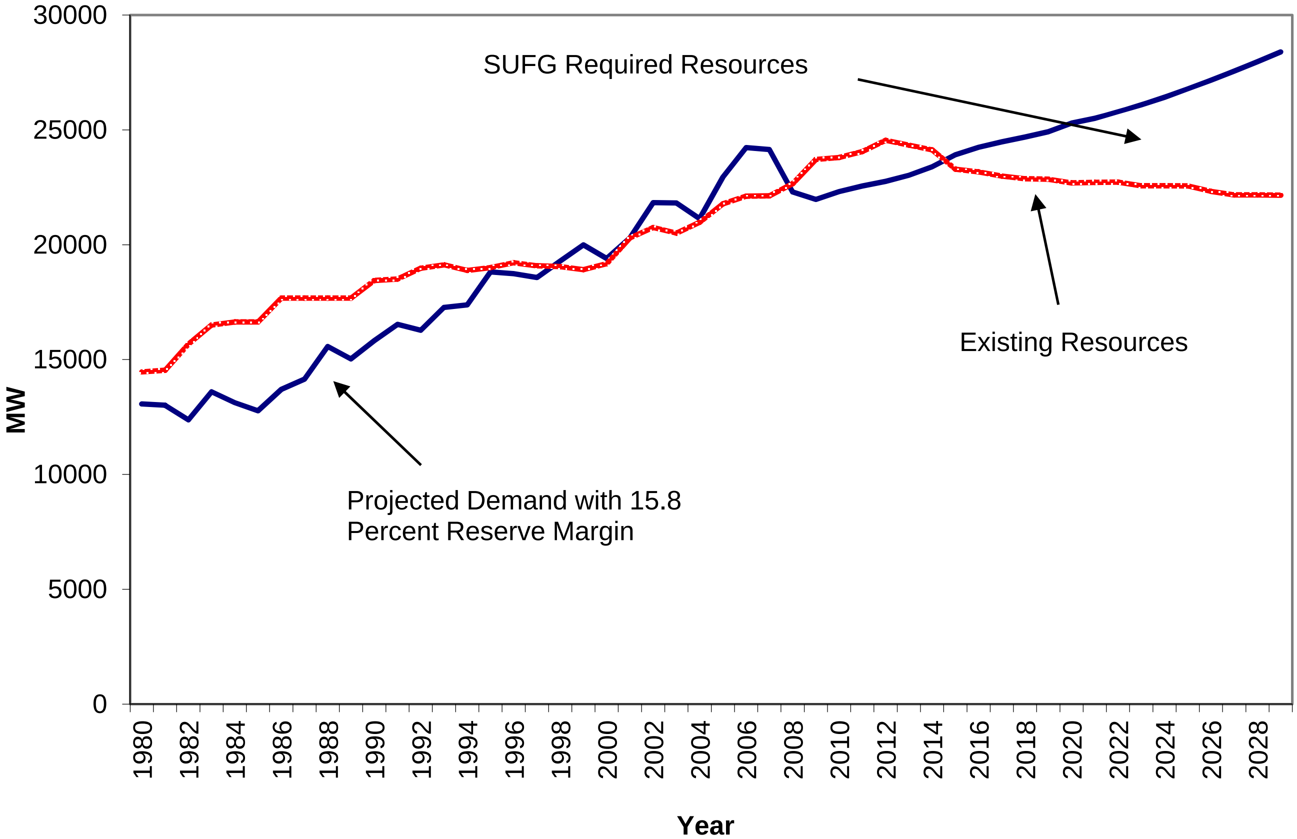
4 Incremental change in capacity is the change in existing/approved capacity from the previous year. The change is due to new, approved capacity becoming operational, retirements of existing capacity, and changes in firm purchases and sales.

5 Projected additional resource requirements is the cumulative amount of additional resources needed to meet future requirements.

6 Total resource requirements are the total statewide resources required including existing/approved capacity and projected additional resource requirements.

7 Resources may be required by individual utilities even if the state as a whole meets or exceeds the statewide reserve margin. Individual utility reserve margins are not allowed to fall below 6 percent.

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



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 feature on the forecast of electricity requirements can be significant if price changes are large.

SUFG's base scenario equilibrium real electricity price trajectory is shown in Table 3-5 and Figure 3-4. Real prices are projected to increase by 20 percent from 2010 to 2017 and then maintain that level for the remainder of the forecast period. The change in prices early in the forecast horizon is significant, thus the electricity requirements projection for this portion of the forecast period is affected. SUFG's equilibrium price projections for two previous forecasts are also shown in Table 3-5 and Figure 3-4. The price projection labeled "2007" is the base case projection contained in SUFG's 2007 forecast and the one labeled "2009" is the base case projections from SUFG's 2009 report. For the prior price forecasts, SUFG rescaled the original price projections to 2009 dollars (from 2005 dollars for the 2007 projection, and from 2007 dollars for the 2009 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

Three major factors primarily determine the differences among the price projections in Figure 3-4: first, the cost of controlling emissions from coal-fired generation facilities to meet air emission standards; second, purchase power costs; and third, capital costs associated with generation plant additions and life extension. It should be noted that a new generating facility is only included after a Certificate of Public Convenience and Necessity is granted by the IURC. Similarly, environmental rules that are in place at the time the forecast was prepared are included, while proposed and potential future rules are not. Thus, the costs associated with meeting the first phase of the Clean Air Interstate Rule (CAIR) are included. The replacement for CAIR, the Cross-State Air Pollution Rule (CSAPR) was finalized after the model runs for this report were completed, thus CSAPR is not modeled in its final form. Other non-finalized rules, such as the Mercury and Air Toxics Standards (MATS), which was proposed in March 2011, and rules affecting greenhouse gas emissions, cooling water, and coal ash disposal are not included. SUFG will produce a separate report that specifically addresses the impact of the various proposed and potential rules. This report is expected to be completed in the fall of 2011. See Chapter 8 of this report for more information on potential future regulations.

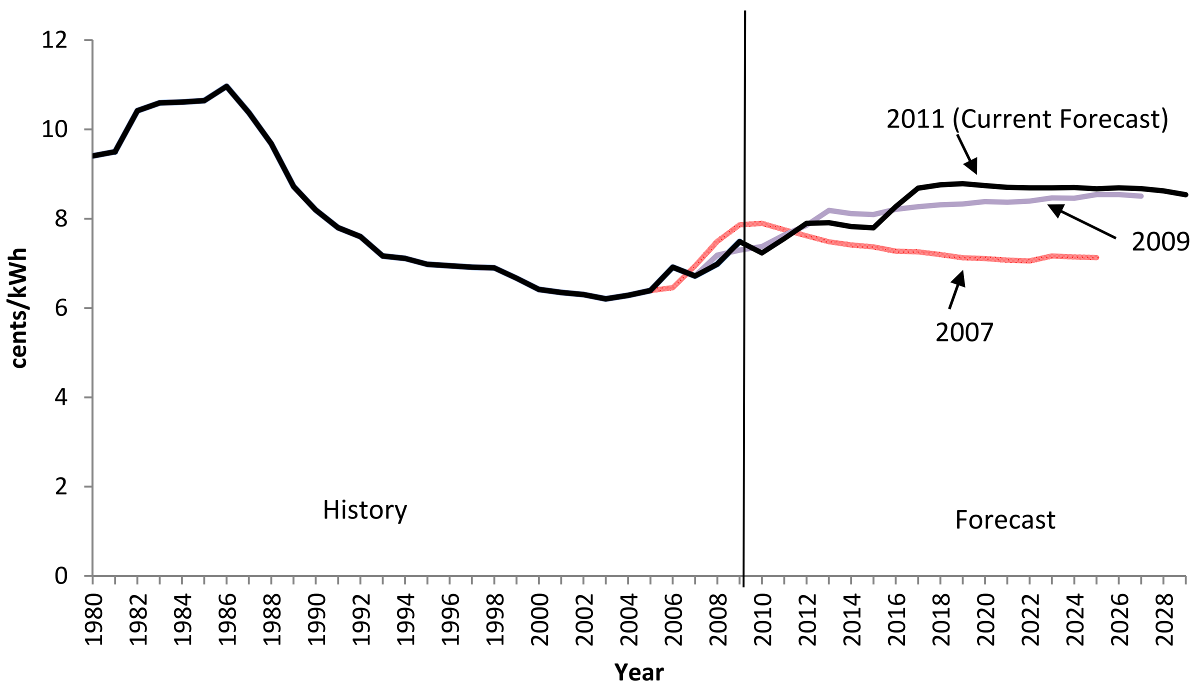
Low and High Scenarios

SUFG has used alternative macroeconomic scenarios, reflecting low and high growth in real personal income, non-manufacturing employment and gross state product. These low probability scenarios are used to indicate the forecast range, or dispersion of possible future trajectories. Tables 3-6 and 3-7 and 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 0.30 percent lower and 0.35 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.

Table 3-5. Indiana Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2007	0.52	2006-2025
2009	0.89	2008-2027
2011	0.88	2010-2019

Figure 3-4. Indiana Real Price Projections in cents/kWh (2009 Dollars) (Historical, Current and Previous Forecasts)



Note: See the Appendix to this report for historical and projected values.

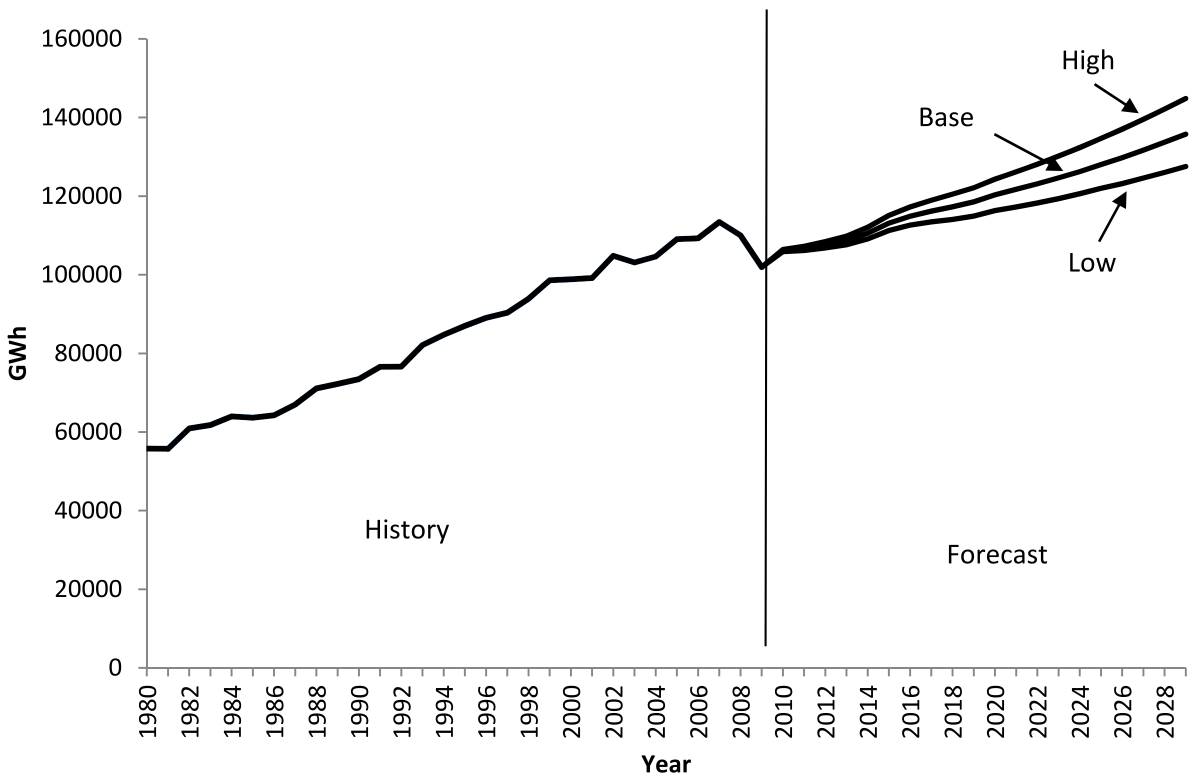
Resource and Price Implications of Low and High Scenarios

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 of generating units. Table 3-8 shows the statewide resource requirements for each scenario. Approximately 6,900 MW over the horizon are required in the high scenario compared to 4,000 MW in the low scenario. By the end of the forecast period, electricity prices in both the high case and the low case are within about 3.0 percent of those projected in the base case. This is because the changes in wholesale purchases required relative to the base scenario tend to be offset somewhat by the allocation of resource cost of more or less energy.

Table 3-6. Indiana Electricity Requirements Average Compound Growth Rates by Scenario (Percent)

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2010-29	1.30	0.98	1.64

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

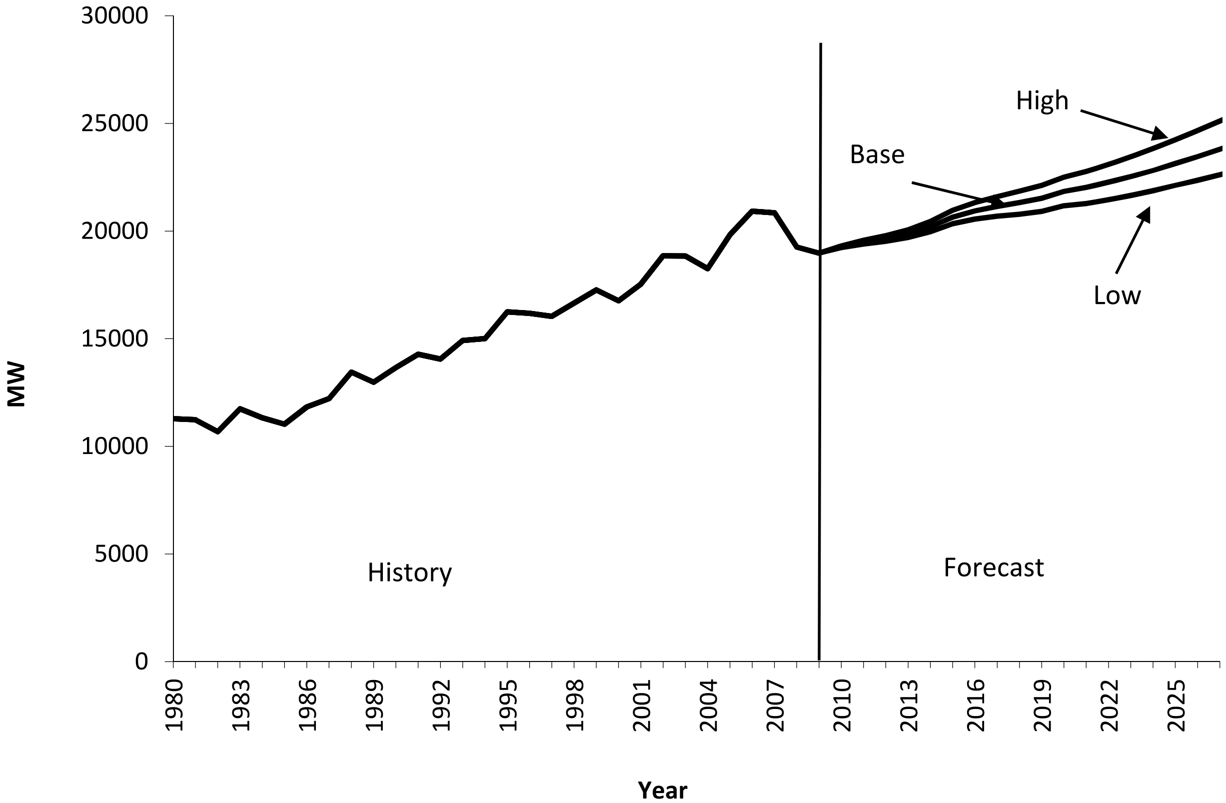


Note: See the Appendix to this report for historical and projected values.

Table 3-7. Indiana Peak Demand Requirements Average Compound Growth Rates by Scenario (Percent)

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2010-29	1.26	0.98	1.58

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



Note: See the Appendix to this report for historical and projected values.

Table 3-8. Indiana Resource Requirements in MW (SUFG Scenarios)

Year	Base				High				Low			
	Peaking	Cycling	Baseload	Total	Peaking	Cycling	Baseload	Total	Peaking	Cycling	Baseload	Total
2010	0	0	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0	0
2013	100	20	0	120	140	20	20	180	60	10	0	70
2014	220	30	70	320	250	40	100	390	170	20	30	220
2015	310	90	330	730	370	150	500	1020	270	50	170	490
2016	380	160	520	1060	470	240	780	1490	320	90	320	730
2017	480	310	700	1490	590	410	1000	2000	360	200	390	950
2018	520	510	780	1810	640	650	1120	2410	450	410	590	1450
2019	570	550	920	2040	710	720	1310	2740	480	440	710	1630
2020	770	640	1190	2600	900	810	1640	3350	650	470	820	1940
2021	800	680	1300	2780	950	850	1820	3620	660	480	880	2020
2022	860	740	1470	3070	1030	900	2060	3990	690	540	1010	2240
2023	920	920	1670	3510	1110	1130	2320	4560	740	720	1110	2570
2024	990	1010	1830	3830	1220	1250	2540	5010	780	760	1220	2760
2025	1030	1090	2110	4230	1310	1380	2840	5530	810	840	1390	3040
2026	1060	1330	2440	4830	1340	1610	3250	6200	860	1060	1640	3560
2027	1270	1400	2690	5360	1620	1720	3520	6860	1020	1110	1880	4010
2028	1350	1470	2940	5760	1760	1850	3800	7410	1090	1170	2040	4300
2029	1490	1590	3160	6240	1910	1980	4090	7980	1170	1250	2210	4630

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 the prices of fossil fuels, 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 the Center for Econometric Model Research (CEMR) at Indiana University.

- 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 February 2011 economic projections as its base scenario. CEMR also produced high and low growth alternatives to the base projection for SUFG's use in the 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.

The Indiana model has four main modules. The first disaggregates total U.S. employment into manufacturing and 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, as cited from "Long-Range Projections 2010-2031" [CEMR] are:

Federal tax rates are assumed to increase over the projection period. Specifically, the average tax rate on personal income and the payroll tax rate each increased by 18 percent. Federal grants to state and local governments are assumed to grow at about 4.6 percent annually early in the projection period and then decline to about a 4.1 percent by the end of the projection period. The federal government deficit declines somewhat but is still more than 6.0 percent of GDP at the end of the projection period as compared to 9.2 percent in 2010.

State and local tax rates are roughly stable over the projection period. This allows these governments to run moderate surpluses through the projection period.

Real exports are assumed to grow at about 5.3 percent through 2019, and then to decelerate gradually to 4.7 percent growth. This produces a (nominal) net export deficit that declines from 3.6 percent of GDP to 2.9 percent (CEMR, 2011).

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 3.05 percent and U.S. employment growth averages 1.25 percent over the 2010 to 2029 period.

In Indiana, total employment is projected to grow at an average annual rate of 1.21 percent from 2010 through 2029. The key Indiana economic projections are:

Real personal income (a residential sector model driver) is expected to grow at a 2.02 percent annual rate.

Non-manufacturing employment (the commercial sector model driver) is expected to average a 1.31 percent annual growth rate over the forecast horizon.

Despite the low growth in manufacturing employment, manufacturing GSP (the industrial sector model driver) is expected to rise at a 3.44 percent annual rate as gains in productivity far outpace meager growth in employment.

CEMR's macroeconomic projections reflect a continuation of the economic recovery. Real Indiana personal income began recovering in 2010. Indiana nonmanufacturing employment and manufacturing output (real GSP) also began to increase in 2010.

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 real personal income is increased by about 0.35 percent per year (to 2.37), non-manufacturing employment growth increases 0.11 percent (to 1.42) while Indiana real manufacturing GSP growth is increased by 0.80 percent (to 4.24). In the low growth alternative, the average growth rates of real personal income, non-manufacturing employment and real manufacturing GSP are reduced by similar amounts (to 1.68, 1.21 and 2.44 percent, respectively).

Demographic Projections

Household demographic 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 0.49 percent per year, for the period 2005-2025. This projection was developed in 2004 and includes projections of county population by age group, the fastest growing age groups are those of age 45-64 (0.45 percent) and age 65 and over (2.39 percent). 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.

Indiana population growth has slowed markedly in recent years. The number of people over age 45 (the groups with fewer occupants per household) is projected to grow more rapidly than the younger population. Thus, the number of people per household is projected to decline and 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 1.4 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 1.00 percent over the forecast period.

Table 4-1. Growth Rates for CEMR Projections of Selected Economic Activity Measures (Percent)

	Short-Run History for Selected Recent Periods					Long-Run Forecast Feb 2007	Long-Run Forecast Feb 2009	Long-Run Forecast Feb 2011
	1985-1990	1990-1995	1995-2000	2000-2005	2005-2010*	2006-2025	2008-2027	2010-2029
United States								
Real Personal Income	2.95	2.04	4.08	1.73	1.43	3.25	2.76	2.80
Total Employment	2.36	1.38	2.37	0.25	-0.52	0.97	1.00	1.25
Real Gross Domestic Product	3.25	2.38	4.36	2.39	0.93	3.20	2.76	3.05
Personal Consumer Expenditure Deflator	3.79	2.77	1.87	2.20	2.12	1.94	1.72	1.51
Indiana								
Real Personal Income	2.50	2.48	3.37	1.17	0.59	2.10	1.63	2.02
Employment								
Total Establishment	2.84	1.91	1.22	-0.28	-1.09	0.80	0.83	1.21
Manufacturing	0.91	1.40	0.07	-2.95	-5.05	-1.10	-1.29	0.30
Non-Manufacturing	3.82	2.20	1.97	0.47	0.05	1.12	1.16	1.31
Real Gross State Product								
Total	6.17	5.83	4.78	1.98	0.83	3.21	2.62	3.02
Manufacturing	4.76	7.95	4.68	3.26	0.63	3.49	2.23	3.44
Non-Manufacturing	6.81	4.86	4.84	1.43	0.90	3.07	2.78	2.86

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"
*2010 values are projections not actual history

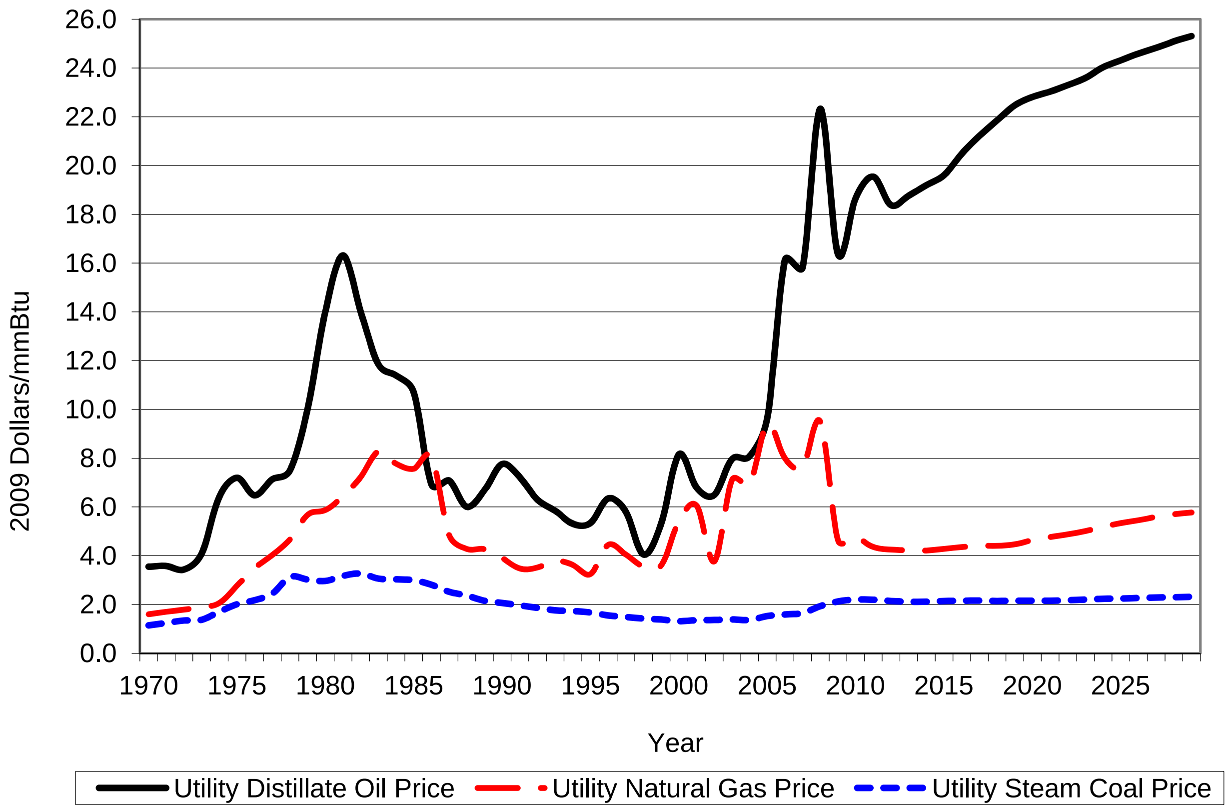
Fossil Fuel Price Projections

The prices of fossil fuels such as coal, natural gas and oil affect electricity demand in separate and opposing 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 opposing 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.

SUFG's modeling system incorporates separate fuel price projections for each of the utility, industrial, commercial and residential sectors. Therefore, SUFG uses four distinct natural gas price projections (one for each sector). Similarly, four distinct oil price projections are used. Coal price projections are included for the utility and industrial sectors only. In this forecast, SUFG has used April 2011 fossil fuel price projections from EIA for the East North Central Region of the U.S. [EIA]. All projections are in terms of real prices (2009 dollars), i.e., projections with the effects of inflation removed. The general patterns of the fossil fuel price projections are:

- Coal price projections are relatively unchanged in real terms throughout the entire forecast horizon as growth in demand is offset by improvements in mining productivity.
- Natural gas price projections exhibit a significant decrease in 2009 coming off of the high prices of 2008. Prices are then projected to remain relatively constant through 2015, with a general increase following for the remainder of the forecast horizon.
- Distillate prices also are projected to decrease significantly in 2009, but recover more quickly with a steady increase through the remainder of the forecast horizon.

Figure 4-1. Utility Real Fossil Fuel Prices



The fossil fuel price projections for the utility sector are presented in Figure 4-1. The general trajectories for the other sectors are similar.

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 load shape, 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 adjustments 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 2009 are considered to be embedded in the calibration data, so no adjustments are necessary.

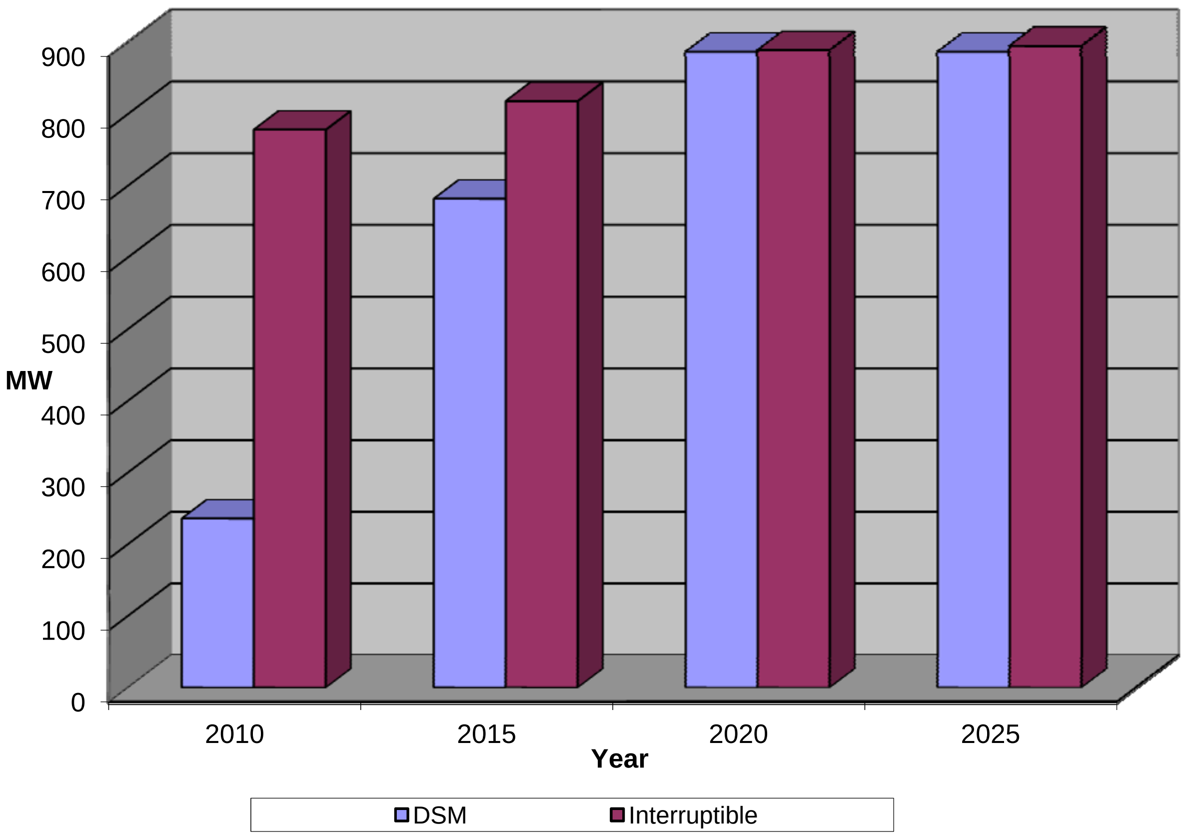
Interruptible loads, such as large customers who agree to curtail a fixed amount of their demand during critical periods in exchange for more favorable rates, are typically treated differently than traditional DSM. Interruptible loads are subtracted from the utility's peak demand in order to determine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

Table 4-2 shows the peak demand reductions from embedded DSM in 2009 and from incremental DSM and interruptible loads available in 2010 in Indiana. These estimates are derived from utility integrated resource plan (IRP) filings and from information collected by SUFG directly from the utilities. DSM projections after 2010 are primarily driven by the IURC's DSM order of December 2009. Since long-term program information was not available at the time this forecast was prepared, SUFG estimated the energy and peak demand savings, as well as the program costs, associated with meeting the DSM rule. Figure 4-2 shows projected values of peak demand reductions for incremental DSM and interruptible loads at five year intervals starting in the year 2010.

Table 4-2. 2009 Embedded DSM and 2010 Peak Demand Reductions (MW)

2009 Embedded DSM	2010 Incremental DSM	2010 Interruptible
461	236	778

Figure 4-2. Projections of Peak Demand Reductions from DSM and Interruptible Loads



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 resource 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 times of high demand and prices, while buy through loads may still be present, with the higher prices passed directly to the customer.

Changes in Forecast Drivers from 2009 Forecast

The SUFG forecast requires exogenous economic assumptions to project electric energy sales, peak demand and prices. Fluctuations in the national and state economies therefore have direct effects on the forecast. SUFG analyzed the impact of the recent recession on different economic variables in Indiana to obtain a better understanding of how these changes affect electricity demand in the state. This section compares the CEMR's projections used in SUFG's 2009 and 2011 forecasts.

Electricity demand is a function of a number of factors, including real personal income, manufacturers' electricity consumption, labor usage intensity, and other economic variables. The economy has direct and indirect implications for electricity consumption in Indiana.

In the time between CEMR's February 2009 (herein referred to as CEMR2009) and February 2011 (CEMR2011) long-range projections, the U.S. economy recovered slightly but some remnants of the recession persist even in 2011.

Tables 4-3 through 4-5 provide comparisons between the two projections. Selected economic variables are reported annually from 2008 through 2014 and for each five year interval beginning in 2015. The tables show long-run projections of real values and percentage change at annual rates for total manufacturing GSP, non-manufacturing employment and personal income. The tables also show the percentage change between CEMR2009 and CEMR2011. Figures 4-3 through 4-5 show long-run projections of real values for the same selected economic variables from 2003 through 2031. Some of the historical values before 2007 differ between the two projections because of data revisions and the use of chain-weighted price indices and deflators.

Non-manufacturing Employment

CEMR forecasts employment at the sectoral level, separating employment into sectors for durable goods manufacturing, non-durable goods manufacturing, and non-manufacturing. Analyzing the non-manufacturing, or service, sector's employment provides insight into Indiana's commercial electricity demand.

Table 4-3 shows that the impact of the recession on non-manufacturing employment occurs largely in the 2008 to 2015 timeframe. In CEMR2011, the projection of non-manufacturing employment for 2010 is about 70,000 employees (or 3.05 percent) lower than in CEMR2009. In 2011 this gap increases and non-manufacturing employment falls to about 85,500 employees (or 3.63 percent) lower than projected in CEMR2009. From 2012 on, CEMR2011 exhibits higher growth than previously estimated, but employment in this sector never returns to previously expected levels.

Figure 4-3 illustrates the comparison between past and current projections for employment in non-manufacturing. CEMR2011 exhibits a similar trajectory to CEMR2009 for part of the forecast horizon, with the most significant deviation between 2008 and 2017.

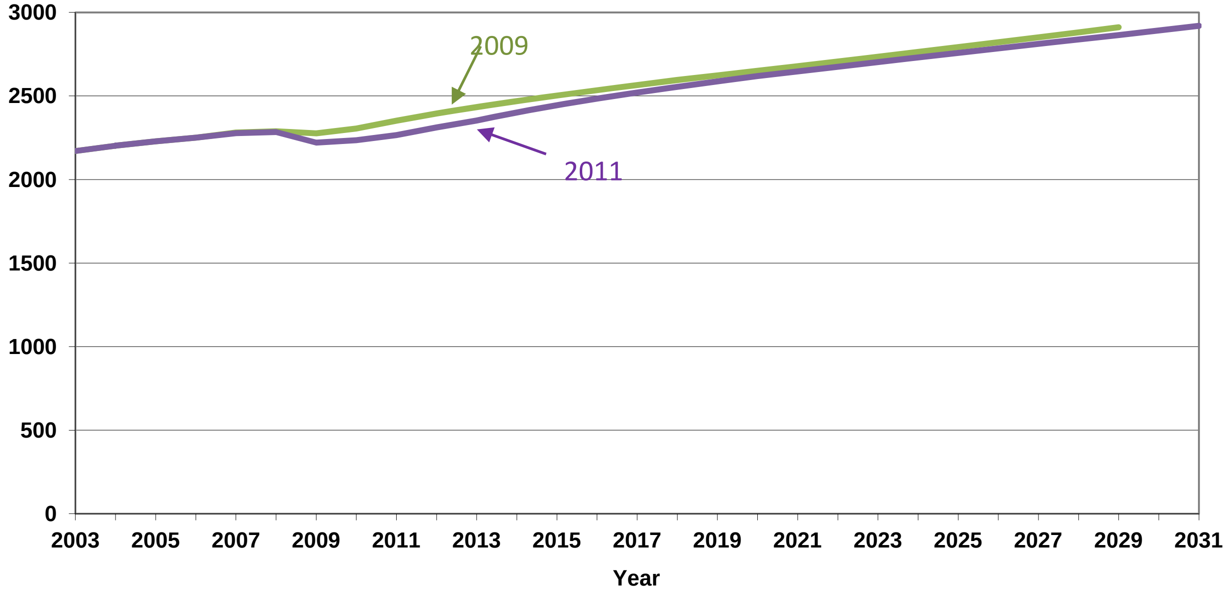
Table 4-3. 2009 and 2011 CEMR Projections for Non-manufacturing Employment

	Year										
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**	**2025**	**2029**
	Thousands of persons										
CEMR2009	2288.8 (0.35)	2276.5 (-0.54)	2305.3 (1.27)	2351.6 (2.01)	2395.3 (1.86)	2433.9 (1.61)	2469.0 (1.44)	2502.2 (1.34)	2650.2 (1.16)	2791.9 (1.05)	2910.9 (1.05)
CEMR2011	2284.3 (0.31)	2220.3 (-2.80)	2235.0 (0.66)	2266.1 (1.39)	2311.8 (2.02)	2353.2 (1.79)	2400.4 (2.00)	2444.8 (1.85)	2618.7 (1.38)	2758.2 (1.04)	2864.5 (1.04)
Percentage change between two projections	-0.20	-2.47	-3.05	-3.63	-3.48	-3.32	-2.78	-2.29	-1.19	-1.21	-1.60

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

Note: Numbers in parentheses indicate percentage change at annual rate

Figure 4-3. Indiana Non-manufacturing Employment (thousands of people)



Real Personal Income

Real personal income provides an important picture of the recession's effects on Indiana. Changes in real personal income will directly influence electricity demand. Real personal income is an input to the residential energy forecasting model.

Table 4-4 and Figure 4-4 show the CEMR projections of real personal income. CEMR2011 follows a similar trajectory to the one for non-manufacturing employment in that it slows in 2008, then decreases in 2009 before beginning to rebound in 2010. However, while the trajectory is similar, the magnitude of the difference between the two sets of projections is larger. CEMR2011 indicates real personal income more than $2 billion dollars (1.04 percent) above CEMR2009 in 2009, with the difference rising to over $10 billion (4.00 percent) by 2025. Unlike the non-manufacturing employment projection, real personal income does reach higher levels than projected in CEMR2009.

Figure 4-4 illustrates that the CEMR2011 real personal income is projected to grow at a steady rate after 2010, with higher growth rates than in CEMR2009.

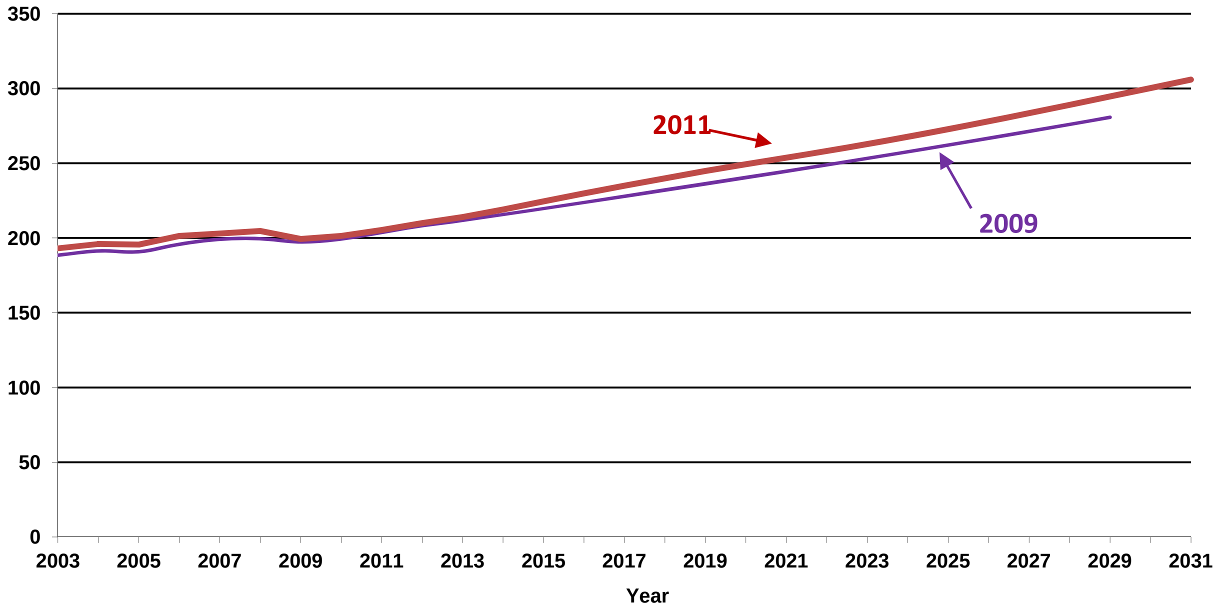
Table 4-4. 2009 and 2011 CEMR Projections for Real Personal Income

	Year										
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**	**2025**	**2029**
	Billions of 2005 $										
CEMR2009	199.54 (0.20)	197.32 (-1.11)	199.25 (0.98)	203.78 (2.27)	208.15 (2.15)	211.79 (1.75)	215.62 (1.81)	219.58 (1.83)	240.49 (1.84)	262.13 (1.74)	280.73 (1.73)
CEMR2011	204.67 (0.83)	199.37 (-2.59)	201.37 (1.01)	205.28 (1.94)	209.87 (2.24)	214.02 (1.98)	218.99 (2.32)	224.48 (2.51)	249.25 (2.12)	272.61 (1.81)	294.67 (1.96)
Percentage change between two projections	2.57	1.04	1.06	0.74	0.83	1.05	1.56	2.23	3.64	4.00	4.96

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

Note: Numbers in parentheses indicate percentage change at annual rate

Figure 4-4. Indiana Real Personal Income (billions of 2005 dollars)



Real Manufacturing Gross State Product

Changes in manufacturing Gross State Product (GSP) will have significant implications for electricity use in the industrial sector. The recession has had a larger impact on manufacturing GSP growth than it has on either non-manufacturing employment or personal income.

Table 4-5 and Figure 4-5 show the CEMR projections for real manufacturing GSP. While the CEMR2011 projection follows a similar pattern to that for real personal income, the deviation from the CEMR2009 projections is more pronounced. As the figure illustrates, after not increasing in 2008 and 2009, real manufacturing GSP shows a modest growth in 2010. The CEMR2011 projection for 2010 was over $2 billion (4.35 percent) above the 2009 level for that year. Real manufacturing GSP continues to grow at a higher rate than in CEMR2009. By 2025, the difference between the two projections grows to over $11 billion, or 11.99 percent.

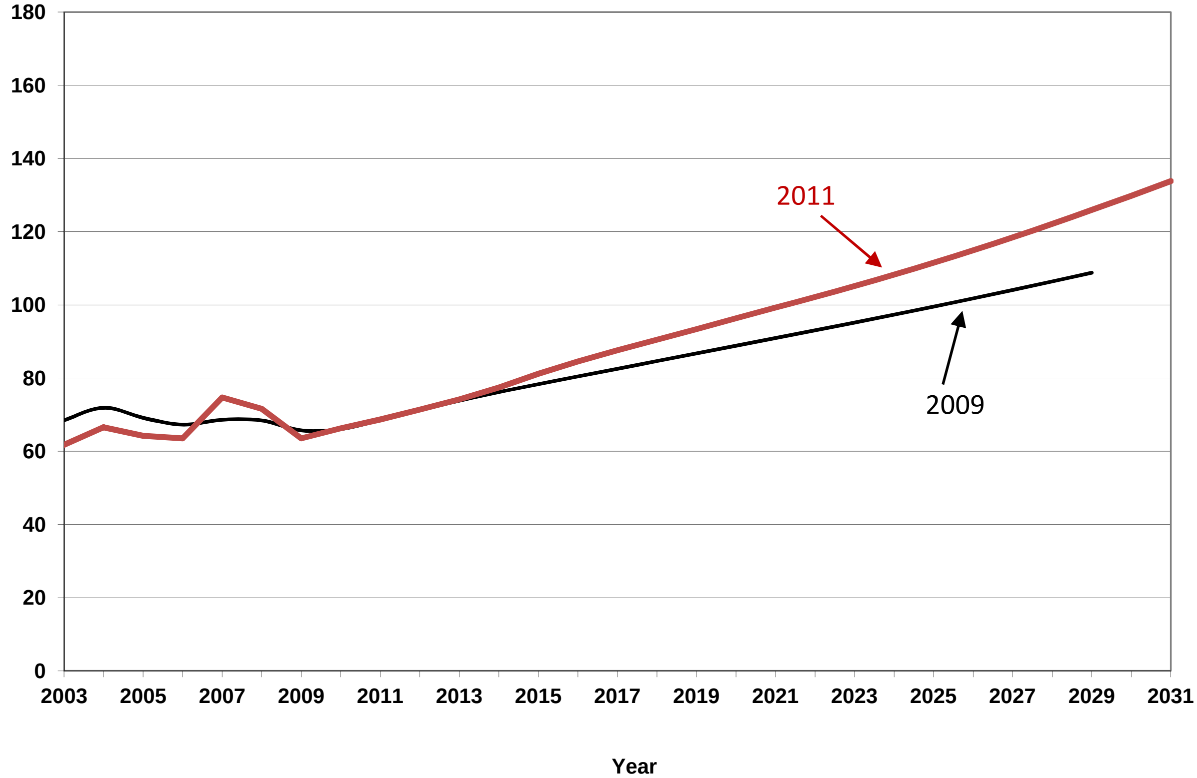
Table 4-5. 2009 and 2011 CEMR Projections for Real Manufacturing GSP

	Year										
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**	**2025**	**2029**
	Billions of 2005 $										
CEMR2009	68.42 (-0.25)	65.71 (-3.97)	66.06 (0.52)	68.54 (3.77)	71.25 (3.94)	73.84 (3.65)	76.17 (3.15)	78.35 (2.86)	88.83 (2.54)	99.54 (2.30)	108.79 (2.25)
CEMR2011	71.60 (-4.18)	63.51 (-11.30)	66.27 (4.35)	68.69 (3.65)	71.37 (3.91)	74.19 (3.95)	77.41 (4.34)	81.16 (4.84)	96.32 (3.49)	111.47 (2.97)	125.94 (3.10)
Percentage change between two projections	4.64	-3.35	0.33	0.21	0.18	0.48	1.63	3.58	8.43	11.99	15.77

Sources: SUFG Forecast Modeling System and various CEMR “Long-Range Projections”

Note: Numbers in parentheses indicate percentage change at annual rate

Figure 4-5. Indiana Real Manufacturing GSP (billions of 2005 dollars)



The transportation equipment industry, including automobile and auto parts manufacturing, accounts for a considerable portion of the total manufacturing GSP in Indiana. In 2009, this sector represented slightly less than one sixth (15.9 percent) of the total real value of products manufactured in the state.

Table 4-6 shows projected growth rates, actual values and percentage rate changes for the transportation equipment industry and includes the comparison between the CEMR2009 and CEMR2011 projections. The table indicates that the recession is having a significant impact on the performance of the automobile sector.

CEMR2011 shows a large reduction in the production of transportation equipment from 2008 to 2009, with a major decline of over 25 percent in 2009. The industry is projected to keep recovering from the recession for the entire forecast period and reach the level projected in CEMR2009 by the year of 2016. Production does not return to pre-2007 levels until after 2014 and is about 11 percent lower than that projected in CEMR2009 after 2010.

While the primary metals industry, including production of steel and aluminum, represented slightly more than 8 percent of Indiana manufacturing GSP in 2008, it accounted for 30.1 percent of the state's industrial electricity sales.

Table 4-7 compares the CEMR projections for 2009 and 2011 for the primary metals industry, which saw about a 16 percent reduction between 2008 and 2010. As in most of the other sectors of the economy, the primary metals industry is projected to see increasing output after 2010. Unlike other industries, CEMR2011 indicates a sustained major recovery for this industry. Real GSP for this sector is projected to exceed the 2008 levels after 2015 for the entire the forecast horizon.

Table 4-6. 2009 and 2011 CEMR Projections for Real GSP Transportation Equipment

	Year										
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**	**2025**	**2029**
	Billions of 2005 $										
CEMR2009	14.69 (-8.12)	13.41 (-8.69)	13.45 (0.27)	13.95 (3.73)	14.49 (3.90)	15.03 (3.72)	15.52 (3.24)	15.98 (2.95)	18.18 (2.43)	20.39 (2.27)	22.26 (2.21)
CEMR2011	13.59 (-8.00)	10.11 (-25.60)	11.34 (12.15)	12.17 (7.33)	12.86 (5.66)	13.57 (5.53)	14.41 (6.22)	15.41 (6.94)	20.15 (5.12)	25.52 (4.80)	30.83 (4.79)
Percentage change between two projections	-7.50	-24.63	-15.70	-12.77	-11.29	-9.75	-7.15	-3.55	10.84	25.15	38.49

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

Note: Numbers in parentheses indicate percentage change at annual rate

Table 4-7. 2009 and 2011 CEMR Projections for Real GSP Primary Metals

	Year										
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**	**2025**	**2029**
	Billions of 2005 $										
CEMR2009	2.94 (-1.68)	2.78 (-5.63)	2.71 (-2.28)	2.74 (0.89)	2.77 (1.05)	2.79 (0.88)	2.80 (0.41)	2.81 (0.13)	2.78 (-0.36)	2.72 (-0.50)	2.66 (-0.55)
CEMR2011	5.21 (-9.47)	4.61 (-11.64)	4.38 (-4.85)	4.41 (0.55)	4.51 (2.26)	4.60 (2.11)	4.73 (2.75)	4.89 (3.43)	5.41 (1.66)	5.80 (1.35)	6.13 (1.35)
Percentage change between two projections	77.09	65.82	61.45	60.92	62.85	64.84	68.67	74.23	94.50	113.21	130.29

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

Note: Numbers in parentheses indicate percentage change at annual rate

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, including 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 the data is correctly measured. 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 specific 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 the stochastic model error is directly related to the magnitude of the estimated variance of this distribution. The greater the variance, the larger the potential 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 inappropriate estimation methods.

References

Center for Econometric Model Research, "Long-Range Projections 2010-2031," Indiana University, February 2011.

Energy Information Administration, "Annual Energy Outlook 2011," April 2011.

Chapter 5

Residential Electricity Sales

Overview

SUFG has access to both econometric and end-use models to project 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 group. The SUFG staff originally developed the econometric model in 1987 when it was estimated from utility specific data. Since then, it has been updated four times, most recently prior to the SUFG 2005 forecast when major components of the model were partially updated. After the release of the 2007 SUFG Indiana Electricity Projections report, SUFG acquired a proprietary end-use model, Residential Energy Demand Model System (REDMS), which blends econometric and engineering methodologies to project energy use on a disaggregated basis. REDMS was obtained to replace an older residential sector end-use oriented model known as REEMS. Both end-use models are descendants of the first generation of end-use models developed at Oak Ridge National Labs (ORNL) during the late 1970s. Initial review indicates that given the same set of primary inputs, REDMS produces forecasts somewhat lower but similar to the econometric model which SUFG has used for several years. This result is markedly different from the results that SUFG experienced with the older end-use model REEMS which projected much lower growth than the econometric model. SUFG has continued to evaluate REDMS and has had the vendor update the model to the latest U. S. Department of Energy (DOE) efficiency standards. SUFG has adapted this end-use model (REDMS) as the primary residential sector energy model, and it is used to project residential electricity sales in this forecast. The end-use model has been implemented for the five Indiana investor-owned utilities (IOUs) and SUFG continues to model residential energy for the not-for-profit utilities (NFPs) with an econometric approach. A discussion of the reasons for SUFG's switch to REDMS and a general description of the residential end-use model follow, 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 five 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. Beginning in 2008 economic activity slowed dramatically. Due in large part to economic weakness, low electric energy sales growth is projected in the residential sector for the near term (see Figure 5-1).

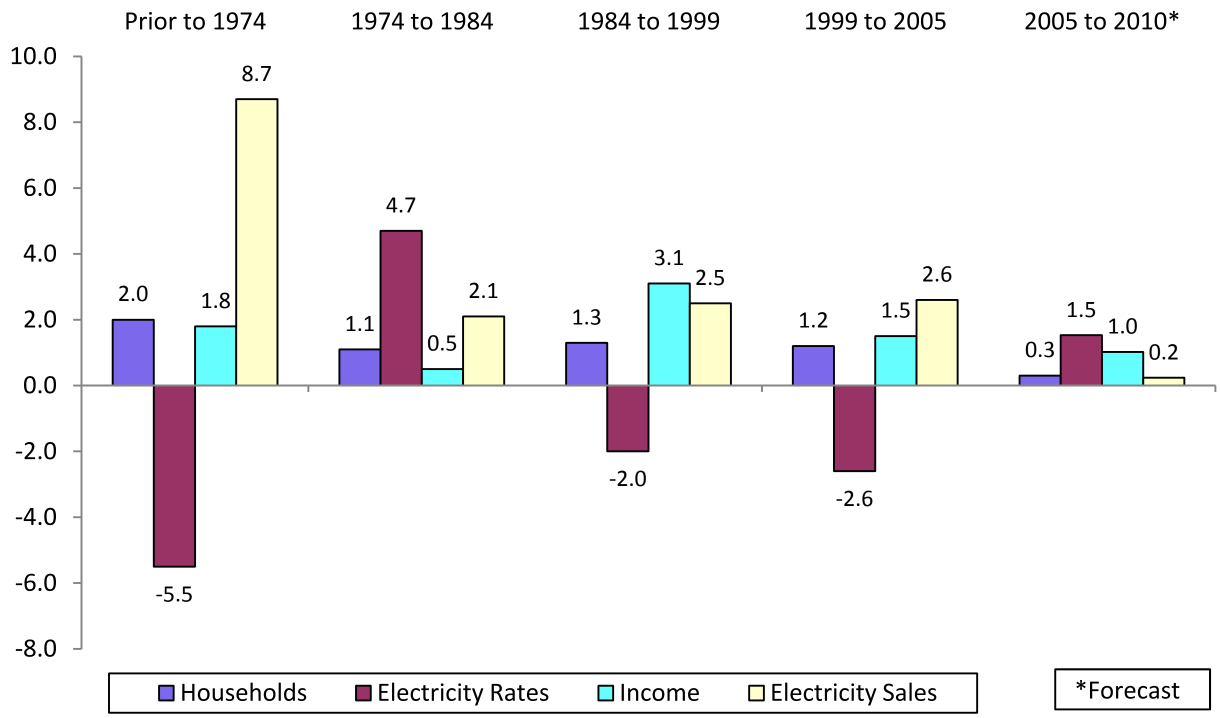
The explosion in residential electricity sales (nearly 9 percent per year) during the decade prior to the Organization of Petroleum Exporting Countries (OPEC) oil embargo in 1974 coincided with the economic stimuli of falling prices (nearly 6 percent per year in real terms) and rising incomes (about 1 percent per year in real terms). This period also was marked by a boom in the housing industry as the number of 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 over 2 percent per year for 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 at only a slightly higher rate than in the post-embargo decade, about 1.3 percent per year. Despite these more favorable market conditions, annual electricity 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 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 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.

From 1999 to 2005, residential household growth has decreased slightly to a 1.2 percent annual rate similar to the 1984 to 1999 period, real electric rates have continued to decline, but the growth in personal income, while positive, has slowed markedly. Despite the slow growth in income, electricity sales have continued to grow at roughly the rate observed during the 1984 to 1999 period.

More recently, from 2005 through the SUFG forecast for 2010, the effects of the economic downturn coupled with rising electricity prices result in much lower growth in electricity sales. Household growth slows to less than one-fourth the rate observed over the preceding twenty years, real electricity prices increase at an average annual rate of 1.5 percent reversing the trend of the previous twenty years, and real household income growth is only about two-thirds of that observed in the early 2000s. The net effect of these changes is to cut projected electricity sales growth rate to less than one-tenth of that observed over the previous twenty years to 0.2 percent per year.

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



REDMS Model Used In Current Forecast

SUFG chose REDMS as the primary residential sector energy projection model for three reasons which are discussed in the following paragraphs.

First, the SUFG econometric model divides customers into two distinct classes depending upon the space heating fuel employed: electricity and other fuels. Over time the distinction between electric space heating and natural gas (or liquefied petroleum gas) space heating has blurred due to the emergence and acceptance of hybrid systems. Hybrid space heating systems combine an electric air to air heat pump with a natural gas or liquefied petroleum gas (LPG) forced air furnace. During the periods of the heating season with relatively warm outdoor air temperatures the heat pump is more efficient than the furnace and is used as a heat source. As the outdoor air temperature drops the efficiency of the heat pump declines (and operating costs increase per unit of heat delivered) and a point is eventually reached at which the gas furnace becomes the more cost effective source of heat. The operating cost breakeven point depends upon the efficiencies of the heat pump and the gas furnace as well as the costs of electricity and gas. These systems are being used in both new construction and retrofit situations since the incremental cost of replacing a failed central air conditioning unit with an air to air heat pump is relatively small. Obviously with these hybrid systems the heat pump is used during the cooling season to provide air conditioning.

Second, at least one major Indiana utility no longer offers a specific electric rate schedule to new customers that choose to use electricity as a space heating fuel source. Also, at least one additional Indiana utility offers a restricted electric space heating rate which is dependent upon equipment efficiency criteria.

Third, federal law has mandated lighting efficiency standards which SUFG feels are best modeled in a direct end-use context. The standards call for a 30 percent improvement in lighting efficiency beginning in 2012 with a phased in efficiency improvement of 60 percent by 2020. Lighting represents a little less than 10 percent of residential electric energy use, so a 60 percent efficiency improvement from current use will reduce residential electricity use by nearly 6 percent in 2020 and thereafter.

Econometric methods work reasonably well to capture trends in efficiency over time, but the lighting standards are more aggressive than historical equipment standards in both the level and timing of the mandated efficiency improvements. For this reason SUFG did not feel comfortable relying on the traditional econometric energy model and chose the direct end-use modeling approach rather than make adjustments to the econometric model projections.

Model Description

The residential end-use model REDMS is the residential analogue to CEDMS, the commercial sector end-use model described in the next chapter of this report. For this reason the description of REDMS below is nearly identical to that of CEDMS in the commercial sector chapter.

Figure 5-2 depicts the structure of the residential end-use model. As the figure shows, REDMS 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 residential sector as it is for modeling the commercial sector. REDMS divides residential dwellings among 3 dwelling types. It also divides energy use in each dwelling type among 10 possible end uses, including a miscellaneous or residual use category. For end uses such as space heating, where non-electric fuels compete with electricity, REDMS further disaggregates energy use among fuel types. (This disaggregation scheme is illustrated at the top of Figure 5-2.) REDMS also divides dwellings among vintages, i.e., the year the dwelling was constructed, and simulates energy use for each vintage and dwelling type.

REDMS projects energy use for each dwelling 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, dwelling type l and vintage t in the forecast year;

t = dwelling vintage (year);

U = utilization, relative to some base year;

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

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

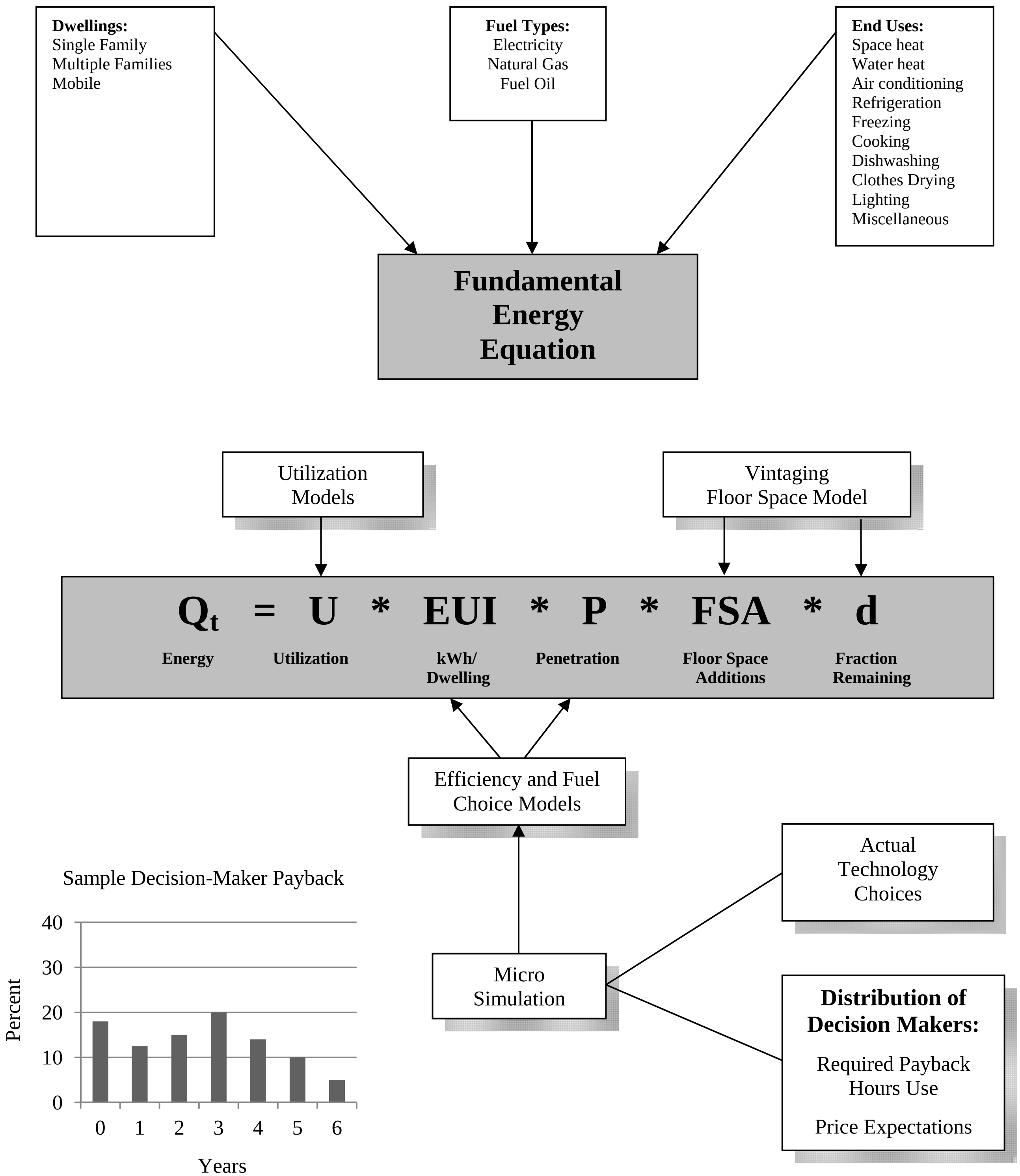
A = dwelling additions by vintage t and dwelling type l; and

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

REDMS' 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.

REDMS jointly determines fuel and efficiency choices through a methodology known as discrete choice microsimulation. Essentially, sample decision-makers in the model make choices from a set of discrete equipment options. Each discrete equipment option is characterized by its fuel type, energy use and cost. REDMS uses the discrete technology choice methodology to model equipment choices for all major end-uses.

Figure 5-2. Structure of Residential End-Use Energy Modeling System



Equipment standards are easily incorporated in REDMS' equipment choice sub-models. Besides efficiency and fuel choices, REDMS 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 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 end-use model include dwellings (residential customers) and electricity prices. The sensitivity of the residential electricity use projection to changes in these variables was simulated one at a time by increasing each variable ten percent above a base scenario level and observing the change in electricity use. The results are shown in Table 5-1. Electricity consumption increases substantially due to increases in the number of customers. As expected, electricity rate increases reduce electric consumption. Changes in natural gas prices, fuel oil prices, and personal income do not affect electricity consumption due in part to the structure of the model and in part due to the vendor's implementation of the model.

Competing fuels (gas and oil) could potentially affect electricity use through two mechanisms; retrofits and penetration in dwelling additions. Once an intial space heating (and subsequently water heating) fuel for a new dwelling is chosen retrofits to an alternative fuel are generally precluded due to the cost hurdle of the capital cost of switching fuels. Such a fuel choice switch would require the addition of gas service and delivery, fuel oil storage and delivery, or an electrical service upgrade and wiring upgrades. In the case of dwelling additions the vendor was unable to discern a statistically significant relationship between fuel prices and fuel specific end-use penetrations. During the period used for model calibration 1990-2005, electric space heating penetration was remarkedly consistent at around 20 percent with natural gas and LPG largely capturing the remainder, real electricity prices were virtually constant, real gas and oil prices drifted upward with considerably volatility but did not exhibit any persistent lasting changes in level.

Personal income effects on fuel and efficiency choices are reflected in the decision makers behavior through the micro-simulation modeling. On average, one would expect those decision makers facing active income or financial constraints to be the decision makers with shorter payback intervals and those without such constraints to have longer payback horizons. Also, the vendor was unable to identify a statistical significant relationship between end-use utilization and personal income.

Table 5-1. Residential Model Long-Run Sensitivities

10 Percent Increase In	Causes This Percent Change in Electric Use
Number of Customers	9.9
Electric Rates	-4.0

Indiana Residential Electricity Sales Projections

Actual sales (GWh), as well as past and current projections, are shown in Table 5-2 and Figure 5-3. The line in the area labeled "History" in the figure are historical consumption. The growth rate for the current base projection of Indiana residential electricity sales is 0.71 percent more than 1.0 percent less than SUFG's 2009 projection of 1.75 percent. The historic and 2011 forecast numbers are provided in the Appendix of this report. Long-term patterns for the entire forecast horizon show that the current projection consistently lies well below both the previous projections. Table 5-3 summarizes SUFG's base projections of residential electricity sales growth since 2007.

Table 5-4 shows the growth rates of the major residential drivers for the current scenarios and the 2009 base case. Household formation is determined by two factors. Demographic projections are the primary determinant, with personal income having a smaller impact. The demographic projections in all four cases are identical. While there is some small variation in personal income among the cases, they are not sufficiently large as to result in a difference in growth rates within two significant digits.

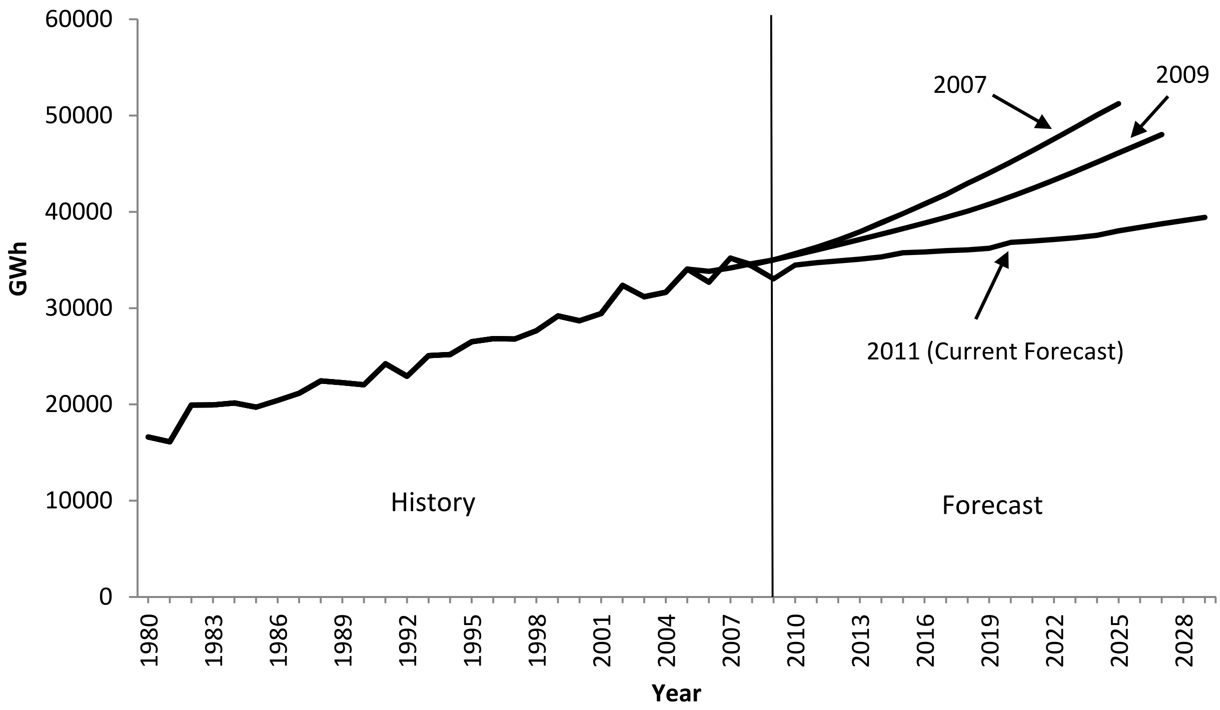
These projections are broken down by the portion of the growth rate attributable to the growth in number of customers and growth in utilization per customer, before and after DSM. As the table shows, more than one half of projected sales growth is attributable to customer growth and the remainder to changes in electric intensity (price and income effects). Much of the residential DSM shifts load from peak usage times to off-peak times and has very little effect on residential electric intensity growth. Overall, residential DSM reduces sales growth by less than 0.1 percent.

As shown in Table 5-5 and Figure 5-4, the growth rates for the high and low residential scenarios are about 0.2 percent higher and 0.1 lower, respectively, than the base scenario. This difference is due primarily to differences in the growth of household income.

Table 5-2. Indiana Residential Electricity Sales Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2007	2.21	2006-25
2009	1.75	2008-27
2011	0.71	2010-29

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



Note: See the Appendix to this report for historical and projected values.

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

Forecast	No. of Customers	Prior to DSM		After DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2011 SUFG Base (2010-2029)	1.00	-0.23	0.77	-0.29	0.71
2009 SUFG Base (2008-2027)	1.00	0.83	1.83	0.75	1.75
2007 SUFG Base (2006-2025)	0.94	1.29	2.23	1.27	2.21

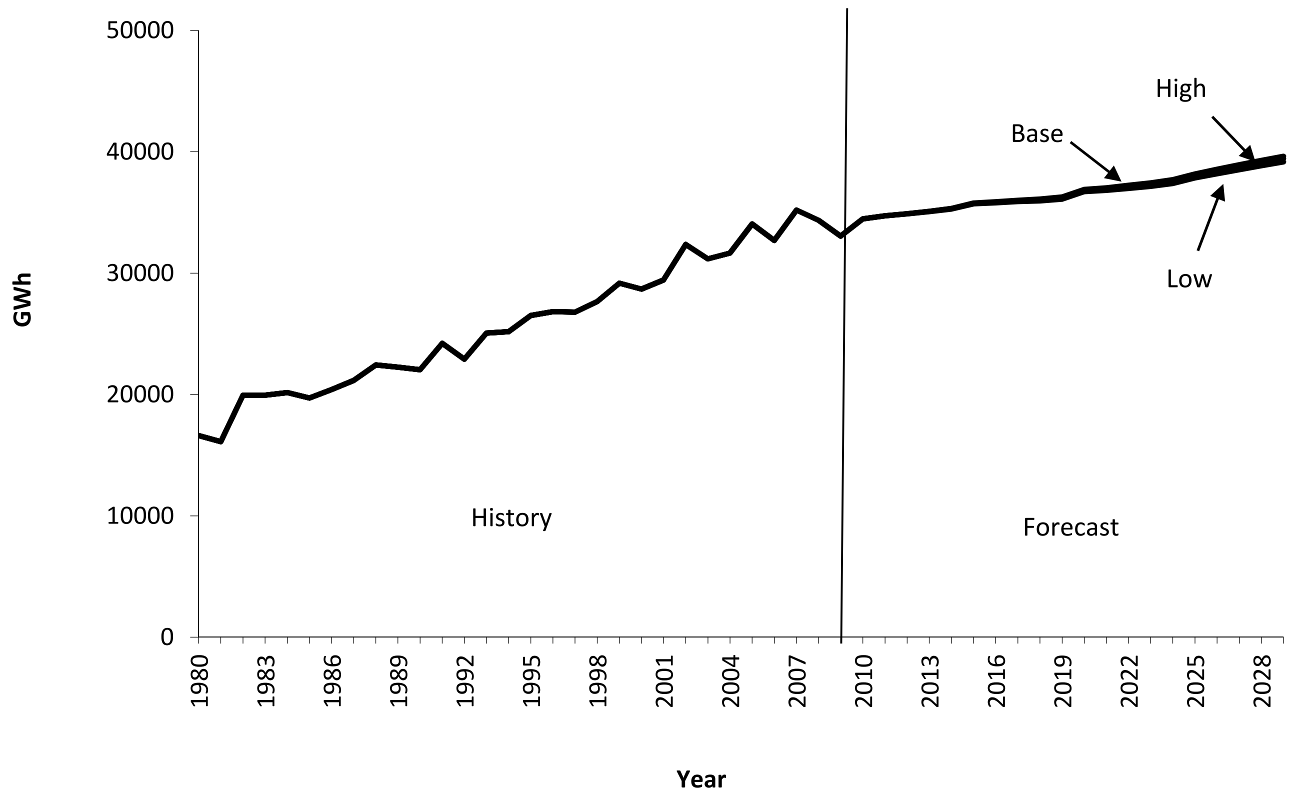
Table 5-4. Residential Model Explanatory Variables - Growth Rates by Forecast (Percent)

Forecast	Current Scenario (2010-2029)			2009 Forecast (2008-2027)
	Base	Low	High	Base
No. of Customers	1.00	1.00	1.00	1.00
Electric Rates	1.08	1.26	0.91	0.66

Table 5-5. Indiana Residential Electricity Sales Average Compound Growth Rates (Percent)

Average Compound Growth Rates			
Forecast Period	Base	Low	High
2010-29	0.71	0.67	0.74

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



Note: See the Appendix to this report for historical and projected values.

Indiana Residential Electricity Price Projections

Historical values and current projections of residential electricity prices are shown in Figure 5-5, with growth rates provided in Table 5-6. The historic and forecast numbers are provided in the Appendix of this report. In real terms, residential electricity prices declined from the mid-1980s until 2002. Real residential electricity prices have risen since 2002 due to increases in fuel costs and the installation of new emissions control equipment. SUFG projects real residential electricity prices to rise until 2013 with the need for additional emissions control equipment and then remain relatively constant. 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.

Figure 5-5. Indiana Residential Base Real Price Projections (in 2009 Dollars)

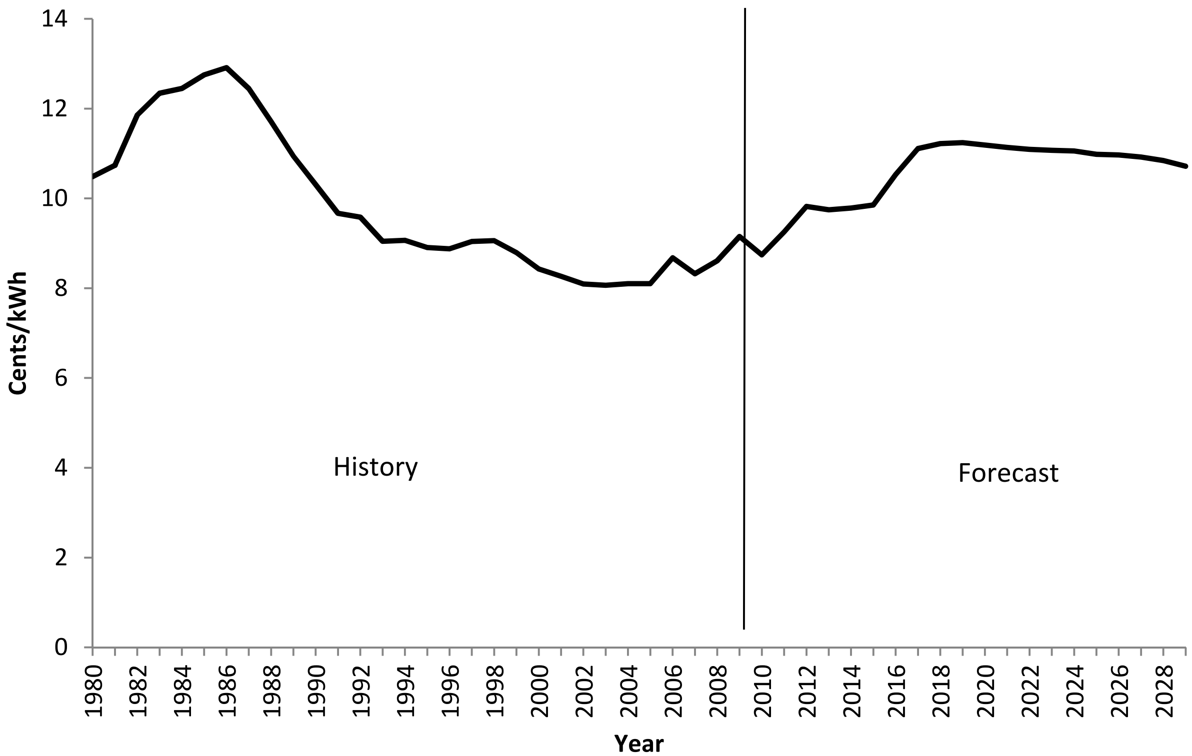


Table 5-6. Indiana Residential Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	**%**
1980-1985	4.00
1985-1990	-4.16
1990-1995	-2.88
1995-2000	-1.09
2000-2005	-0.79
2005-2009	3.10
2010-2029	1.08

Note: See the Appendix to this report for historical and projected values and an explanation of how SUFG arrives at these numbers.

Chapter 6

Commercial Electricity Sales

Overview

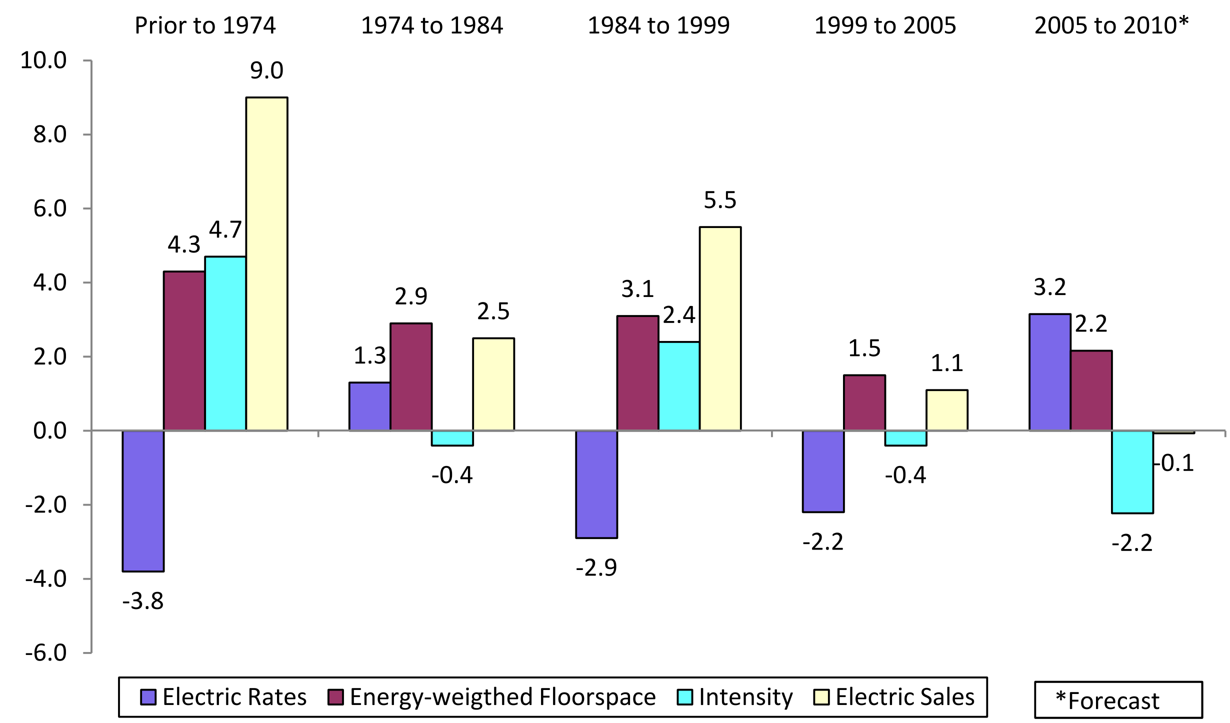
SUFG has two distinct models of commercial electricity sales, econometric and end-use, that have specific strengths and complement each other. SUFG staff developed the econometric model and acquired a proprietary end-use model, Commercial Energy Demand Modeling System (CEDMS). CEDMS is a descendant of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

For a few years in the mid 1990s, SUFG relied on its own 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. SUFG then 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. Second, in contrast to the significant differences between the residential end-use and econometric model projections (discussed in Chapter 5), the differences between the commercial end-use and econometric models are small, since both models forecast similar changes in electric intensity. SUFG used a recently upgraded version of CEDMS for this set of projections.

Historical Perspective

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

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



Changes in electric intensity, expressed as changes in electricity use per square foot (sqft) 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 period, 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.

Over the 1999 to 2005 timeframe, a decrease in economic activity retarded growth in the stock of commercial floor space, led to negative growth in intensity of electricity use, and slowed growth in electricity sales despite continued declines in real electricity prices. Recently the current recession coupled with increasing real electricity prices has accelerated these trends, with the notable exception of the stock of commercial floor space. For 2005 through 2010 real electricity prices have risen, commercial floor space grew at a slightly faster rate than that observed during the previous few years, with intensity of electricity use continuing to decline, and commercial sector electricity use stagnating.

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 categorizes commercial buildings among 21 building types. It also divides energy use in each building type among 9 possible end uses, including an other or 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

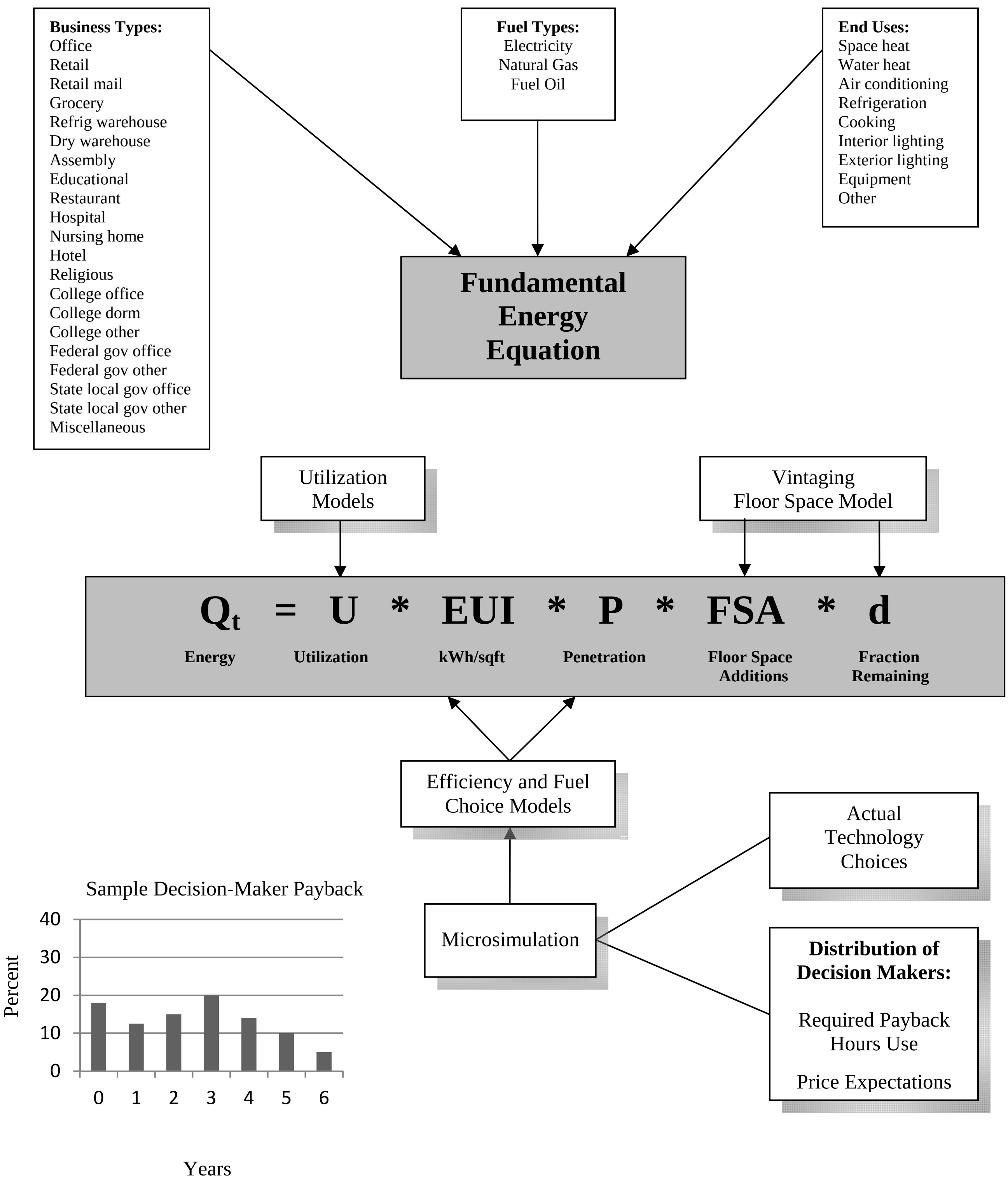
d = fraction of floor space of vintage t still standing in forecast year T.

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. CEDMS uses the discrete technology choice methodology to model equipment choices for HVAC, water heating, refrigeration and lighting. HVAC and lighting account for 80 percent of total electricity use by commercial firms.

Equipment standards are easily incorporated in CEDMS’ equipment choice sub-models. In addition to 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.

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



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) and electricity prices. The sensitivity of the electricity sales 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.

Table 6-1. Commercial Model Long-run Sensitivities

10 Percent Increase In	Causes This Percent Change in Electric Sales
Buildings	10.5
Electric Rates	-2.6

Indiana Commercial Electricity Sales Projections

Historical data as well as past and current projections are illustrated in Table 6-2 and Figure 6-3. As can be seen, the current base projection of Indiana commercial electricity sales growth is 0.89 percent. The historical and 2011 forecast values are provided in the Appendix of this report. The growth rates for the major explanatory variables are shown in Table 6-3. Table 6-4 summarizes SUFG's base projections of commercial electricity sales growth for the last three SUFG forecasts.

Floor space growth is partially offset by decreases in utilization. Utilization, the amount of energy used per unit of floor space, decreases because of increasing prices and the implementation of new efficiency standards. Incremental DSM programs have a small effect on electricity sales.

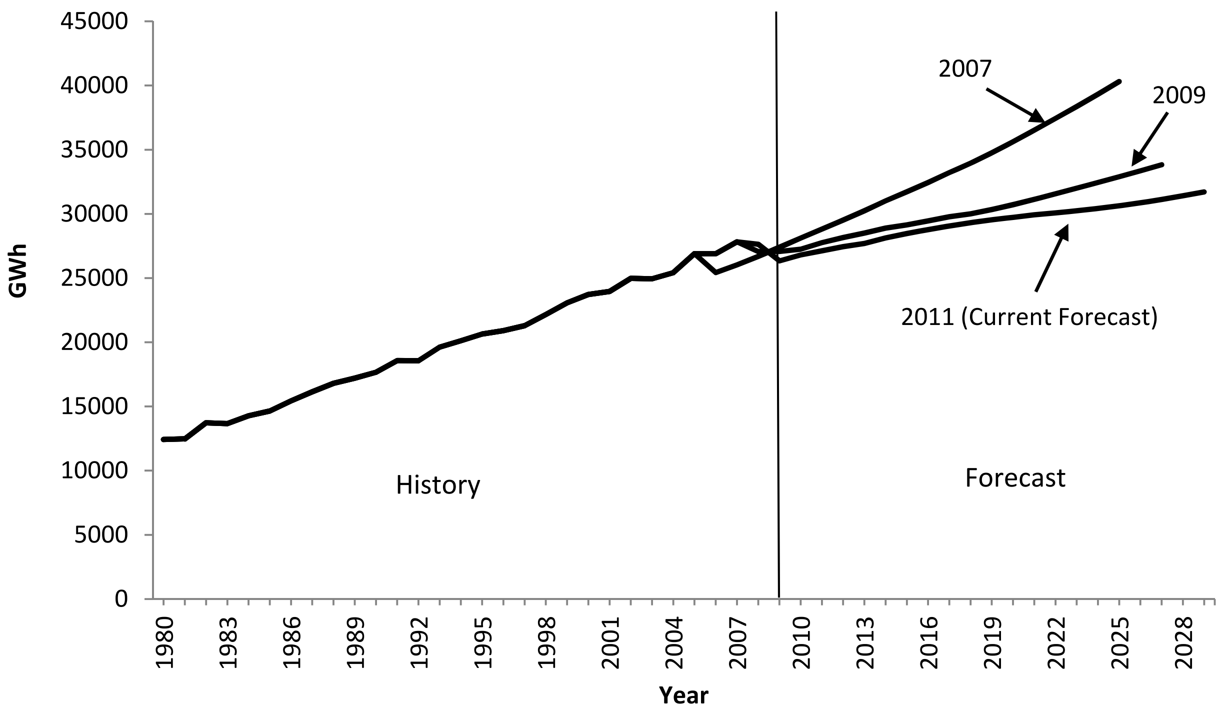
As shown in Figure 6-3, the current projection lies well below the 2007 forecast. The current projection starts out at about the same level but grows at a lower rate. The slower growth rate is due to a combination of the macroeconomic projections and higher projected commercial sector electricity prices.

As shown in Table 6-5 and Figure 6-4, the growth rates for the low and high scenarios are about 0.09 percent lower and 0.08 percent higher than the base scenario, respectively. These differences are almost entirely due to a difference in floor space growth.

Table 6-2. Indiana Commercial Electricity Sales Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2007	2.46	2006-25
2009	1.18	2008-27
2011	0.89	2010-29

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



Note: See the Appendix to this report for historical and projected values.

Table 6-3. Commercial Model – Growth Rates (Percent) for Selected Variables (2011 SUFG Scenarios and 2009 Base Forecast)

Forecast	Current Scenario (2010-2029)			2009 Forecast (2008-2027)
	Base	Low	High	Base
Electric Rates	0.87	1.03	0.74	0.73
Natural Gas Price	0.77	0.77	0.77	0.29
Energy-weighted Floor Space	1.18	1.10	1.26	1.21

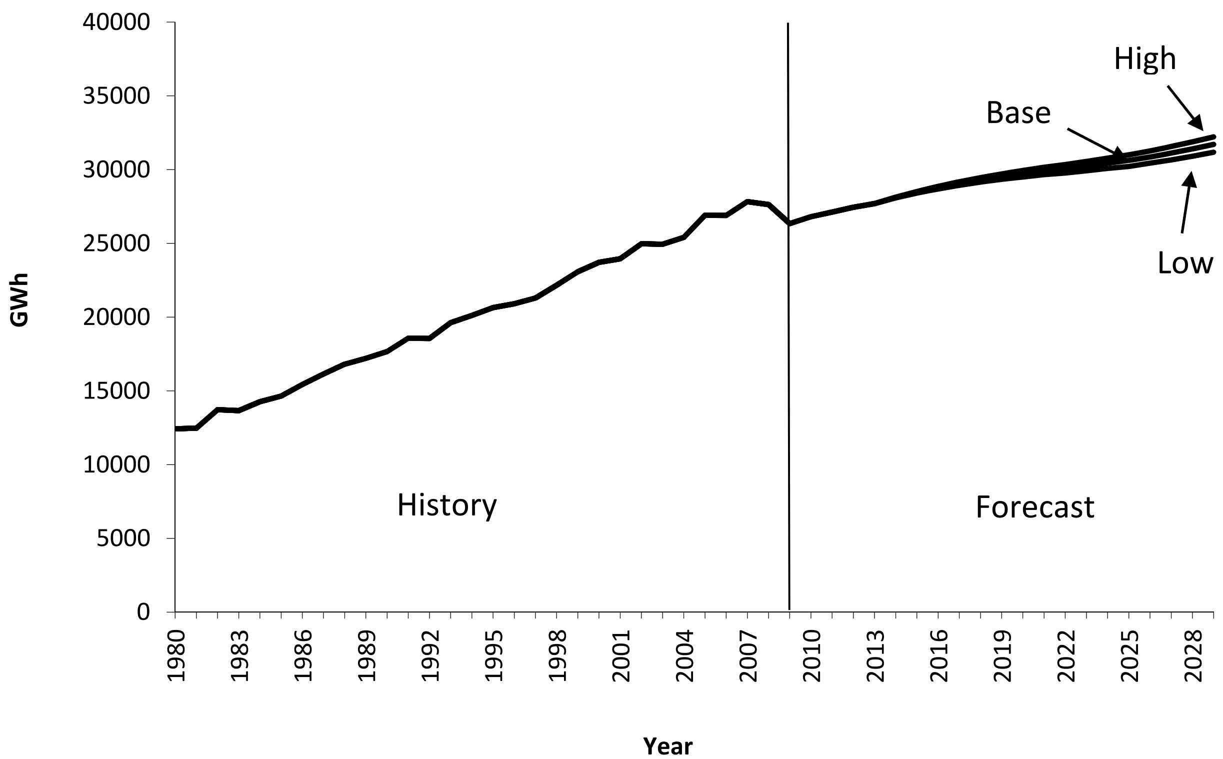
Table 6-4. History of SUFG Commercial Sector Growth Rates (Percent)

Forecast	Electric Energy-weighted Floor Space	Prior to DSM		After DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2011 SUFG Base (2010-2029)	2.08	-1.13	0.95	-1.19	0.89
2009 SUFG Base (2008-2027)	1.21	0.02	1.23	-0.03	1.18
2007 SUFG Base (2006-2025)	2.11	0.35	2.46	0.35	2.46

Table 6-5. Indiana Commercial Electricity Sales Average Compound Growth Rates by Scenario (Percent)

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2010-29	0.89	0.80	0.97

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



Note: See the Appendix to this report for historical and projected values.

Indiana Commercial Electricity Price Projections

Historical values and current projections of commercial electricity prices are shown in Figure 6-5, with growth rates provided in Table 6-6. The historical and forecast numbers are provided in the Appendix of this report. In real terms, commercial electricity prices declined from the mid-1980s until 2002. Real commercial electricity prices have risen since 2002 due to increases in fuel costs and the installation of new emissions control equipment. SUFG projects real commercial electricity prices to rise until 2013 with the need for additional emissions control equipment and then remain relatively constant. SUFG's real price projections for the individual IOUs all follow the same pattern as the state as a whole, but there are variations across the utilities.

Figure 6-5. Indiana Commercial Base Real Price Projections (in 2009 Dollars)

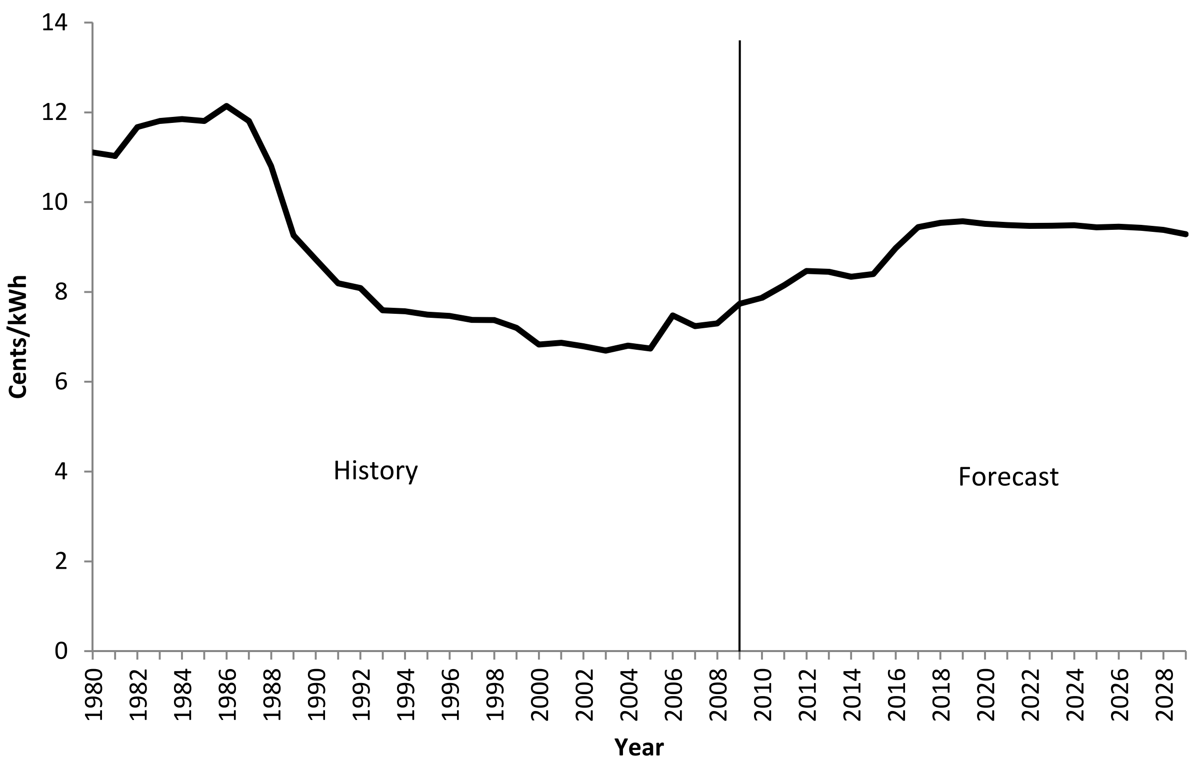


Table 6-6. Indiana Commercial Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	**%**
1980-1985	1.23
1985-1990	-5.88
1990-1995	-2.98
1995-2000	-1.85
2000-2005	-0.26
2005-2009	3.51
2010-2029	0.87

Note: See the Appendix to this report for historical and projected values and an explanation of how SUFG arrives at these numbers.

Chapter 7

Industrial Electricity Sales

Overview

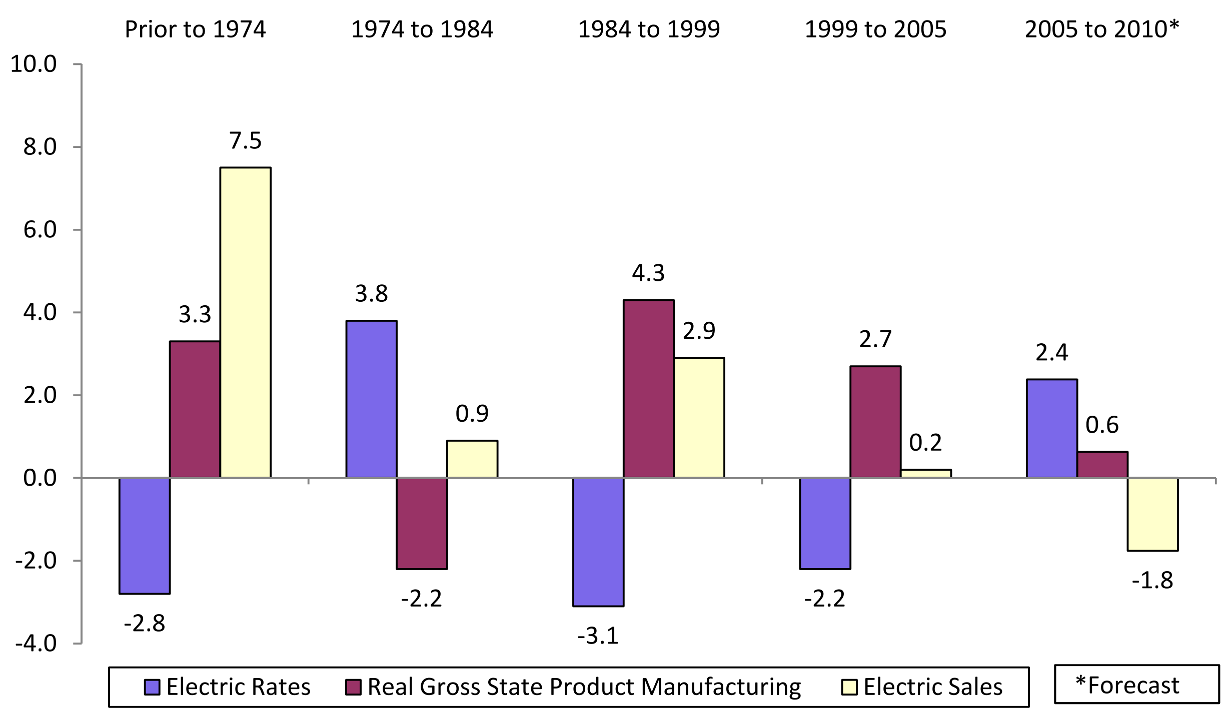
SUFG currently uses several models to analyze and forecast electricity use in the industrial sector. The primary forecasting model is INDEED, an econometric model developed by the Electric Power Research Institute (EPRI), which is used to model the electricity use of 15 major industry groupings in the 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 of electricity purchases 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 15 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 are 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 15 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 five recent periods of distinctly different economic activity and growth — the decade prior to the oil embargo of 1974, 1974-1984, 1984-1999, the more recent period, 1999-2005 and the current period, 2005-2010. The 2005-2010 period includes data from both historical and projected years. Figure 7-1 shows state growth rates for real manufacturing product, real electric rates and electric energy sales for the four periods.

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



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 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 ensuing period, 1984-1999, experienced another dramatic turnaround. The growth rate of industrial output once again became positive, and was 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 these 15 years.

The effect of the economic slowdown from 1999 to 2005 is particularly pronounced in the industrial sector. During this period, real industrial electricity prices declined, but this decline was partially offset by a moderate growth in manufacturing output, resulting in stagnant growth in industrial electricity use. Since 2005 real industrial electricity prices have increased, real growth in manufacturing output has declined, and overall growth in industrial electricity has turned negative. Unlike the residential (Chapter 5) and commercial (Chapter 6) sectors, where decreased economic activity since 1999 has resulted in slower but positive growth in electricity use, industrial electricity use has declined; however, manufacturing sector electricity use is still expected to increase over the forecast horizon.

The Econometric Model

SUFG's primary industrial-sector forecasting model, INDEED, consists of a set of econometric models for each of Indiana's major industries listed in Table 7-1. The general structure of the models is illustrated in Figure 7-2.

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. Six-tenths of state GSP is accounted for by the following industries: primary metals, 5 percent; fabricated metals, 5 percent; industrial machinery and equipment, 8 percent; chemicals, 15 percent; transportation equipment, 21 percent; and electronic and electric equipment, 7 percent.

The share of total electricity consumed by each industry is shown in the second column of Table 7-1. Both the chemical and primary metals industries are very electric intensive industries. Combined, they account for nearly one-half 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 sector employment projections by a projection of GSP per employee, a measure of labor productivity.

This is the fourth SUFG forecast developed since CEMR switched from the SIC to the newer NAICS (North American Industry Classification System) for categorization of industrial economic activity. Generally, the NAICS is more detailed than the SIC system. Since SUFG is still using the SIC system, SUFG maps industrial economic activity projections from the NAICS measures used by CEMR to the older SIC measures used in SUFG's models. This process was relatively straightforward with the exception of SIC 28, chemical manufacturing. In SIC 28, chemical manufacturing, SUFG used the CEMR GSP growth projections for the manufacturing sector as a whole. This was necessary because CEMR's projections did not specifically include chemical manufacturing, a large purchaser of electricity in Indiana.

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.

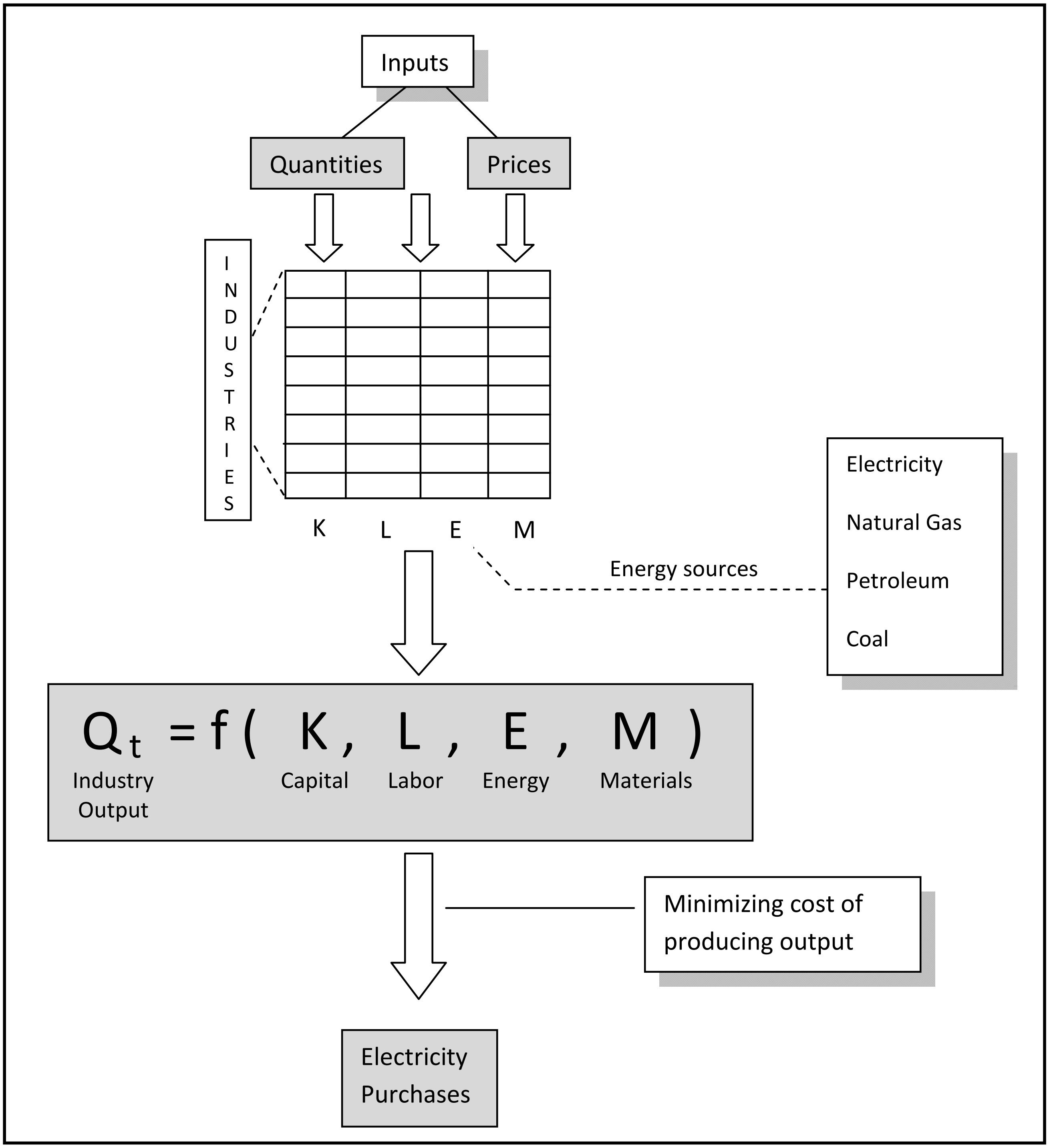
As described earlier in this chapter, INDEED captures the competition between the various inputs for their share of the cost of production by assuming firms seek the mix of inputs that minimize the production cost for a given level of output. Unit costs of natural gas, oil, coal, capital, labor and materials are inputs to the SUFG system, while the cost per kWh of electricity is determined by the SUFG modeling system. For fuel prices SUFG uses the current EIA forecast, which assumes that real natural gas prices in the industrial sector "spiked" in 2008, then will decline at about 10.0 percent per year for the next five years and increase at a rate of about 1.8 percent per year thereafter. Distillate fuel prices are assumed to follow a similar pattern, with a maximum real price in 2008 followed by five years of declines at 4.0 percent per year and growing at about the same rate as natural gas (1.9 percent per year) in the later years. 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 per dollar of GSP, are shown in column five of Table 7-1. With all but one (primary metals) of the intensities expected to decrease, industry-wide electricity intensity is expected to decline modestly 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 industrial electricity use across all sectors in the base scenario is expected to increase at an average of 2.16 percent per year, prior to DSM, over the forecast horizon.

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

SIC	Name	Current Share of GSP	Current Share of Electricity Sales	Current Intensity	Forecast Growth in GSP Originating by Sector	Forecast Growth in Electricity by Intensity by Sector	Forecast Growth in Electricity Sales by Sector
20	Food & Kindred Products	4.47	6.82	0.58	2.84	-1.78	1.06
24	Lumber & Wood Products	2.48	0.69	0.10	2.84	-1.52	1.31
25	Furniture & Fixtures	4.52	0.36	0.03	2.81	-1.17	1.64
26	Paper & Allied Products	1.72	2.76	0.61	2.84	-1.80	1.04
27	Printing & Publishing	3.25	1.34	0.16	2.84	-1.76	1.07
28	Chemicals & Allied Products	15.50	18.95	0.46	2.84	-1.19	1.65
30	Rubber & Misc. Plastic Products	2.88	6.24	0.82	3.42	-1.40	2.03
32	Stone, Clay, & Glass Products	4.58	5.50	0.45	2.81	-1.52	1.29
33	Primary Metal Products	5.23	30.10	2.18	2.35	0.31	2.66
34	Fabricated Metal Products	4.81	5.03	0.40	4.28	-1.49	2.78
35	Industrial Machinery & Equipment	7.81	4.28	0.21	4.53	-1.69	2.83
36	Electronic & Electric Equipment	6.64	5.24	0.30	2.49	-1.75	0.74
37	Transportation Equipment	21.42	8.20	0.14	6.12	-2.15	3.97
38	Instruments And Related Products	6.15	1.08	0.07	2.81	-1.19	1.62
39	Miscellaneous Manufacturing	3.32	0.59	0.07	2.81	-3.87	-1.06
Total	Manufacturing	100.00	100.00	0.38	3.95	-1.79	2.16

Figure 7-2. Structure of Industrial Energy Modeling System



Summary of Results

Model Sensitivities

Table 7-2 shows the impact of a 10 percent increase in each of the model inputs on all industrial electricity consumption in the econometric model. Electricity sales (GWh) 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 percent change in forecast industrial electricity use after 10 years.

Table 7-2. Industrial Model Long-run Sensitivities

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

Indiana Industrial Energy Projections: Current and Past

Past and current projections for industrial energy sales as well as overall annual average growth rates for the current and past forecasts are shown in Table 7-3 and Figure 7-3. The area labeled as "History" in the figure indicates historical consumption. Historical and forecast values are provided in the Appendix of this report.

The impact of industrial sector DSM programs on growth rates for the 2007, 2009, and current forecasts is displayed in Table 7-4. The table also disaggregates the impact on energy growth of output, changes in the mix of output and electricity intensity. Like the residential and commercial sectors, industrial sector DSM programs have a modest impact on industrial sector electricity purchases. The effect of earlier conservation activities are embedded in the historical data and SUFG's projections.

The current forecast projects that industrial sector electricity sales will grow from the 2009 level of approximately 35,000 GWh to over 54,000 GWh by 2029. This growth rate of 2.11 percent per year is substantially higher than both the 0.89 percent rate projected for the commercial sector and the 0.71 percent rate projected for the residential sector. As shown in Figure 7-3, the current forecast lies below those of the 2009 and 2007 forecasts throughout the forecast horizon. Like the other sectors, rising real electricity prices coupled with a weak macroeconomic outlook result in a more conservative forecast of electricity use.

Indiana Industrial Energy Projections: SUFG Scenarios

Table 7-5 and Figure 7-4 shows how industrial requirements differ by scenario. Industrial sales, in the high scenario, are expected to increase to about 62,000 GWh by 2029, over 14 percent higher than the base projection. In the low scenario, industrial sales grow more slowly, which results in 47,500 GWh sales by 2029, more than 12 percent below the base scenario.

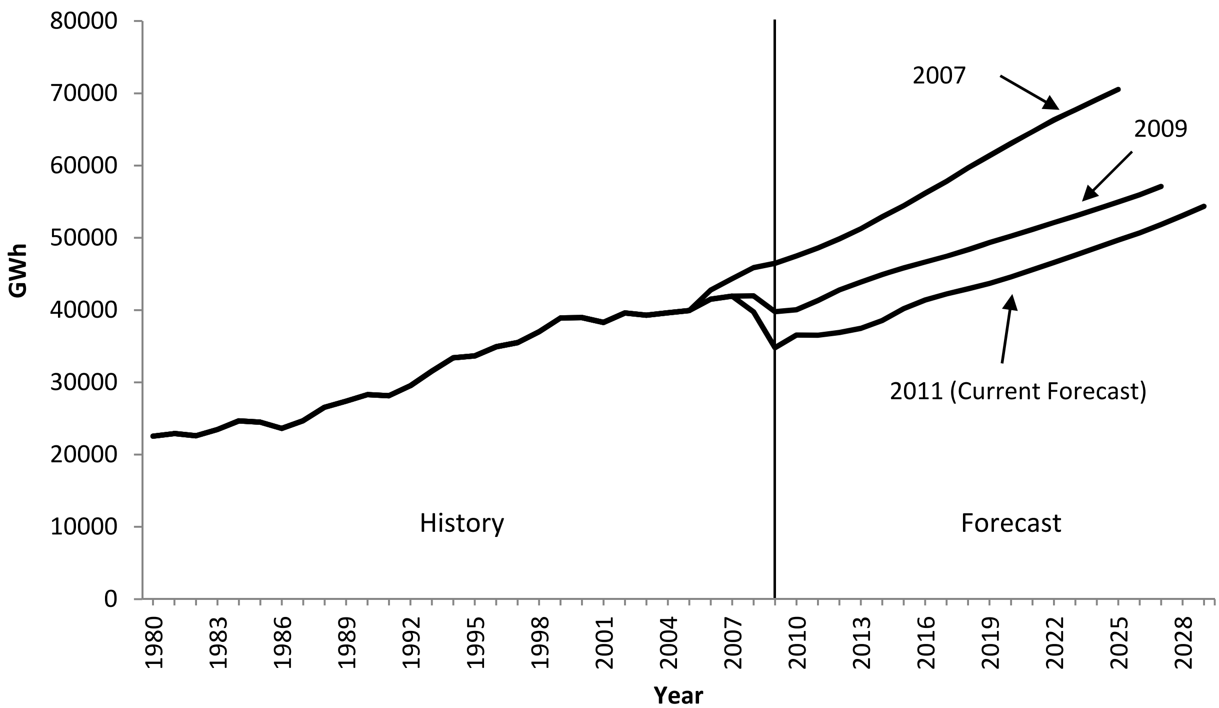
The wide range of forecast sales is caused primarily by the equally wide range of the trajectories of industrial output contained in the CEMR low and high scenarios for the state. In the base scenario GSP in the industrial sector grows 3.95 percent per year during the forecast period. That rate is 4.63 percent in the high scenario and 3.27 percent in the low scenario. This reflects the uncertainty regarding Indiana's industrial future contained in these forecasts.

The high and low scenarios reflect optimistic and pessimistic views, respectively, regarding the ability of Indiana's industries to compete with producers from other states.

Table 7-3. Indiana Industrial Electricity Sales Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2007	2.67	2006-25
2009	1.63	2008-27
2011	2.11	2010-29

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



Note: See the Appendix to this report for historical and projected values.

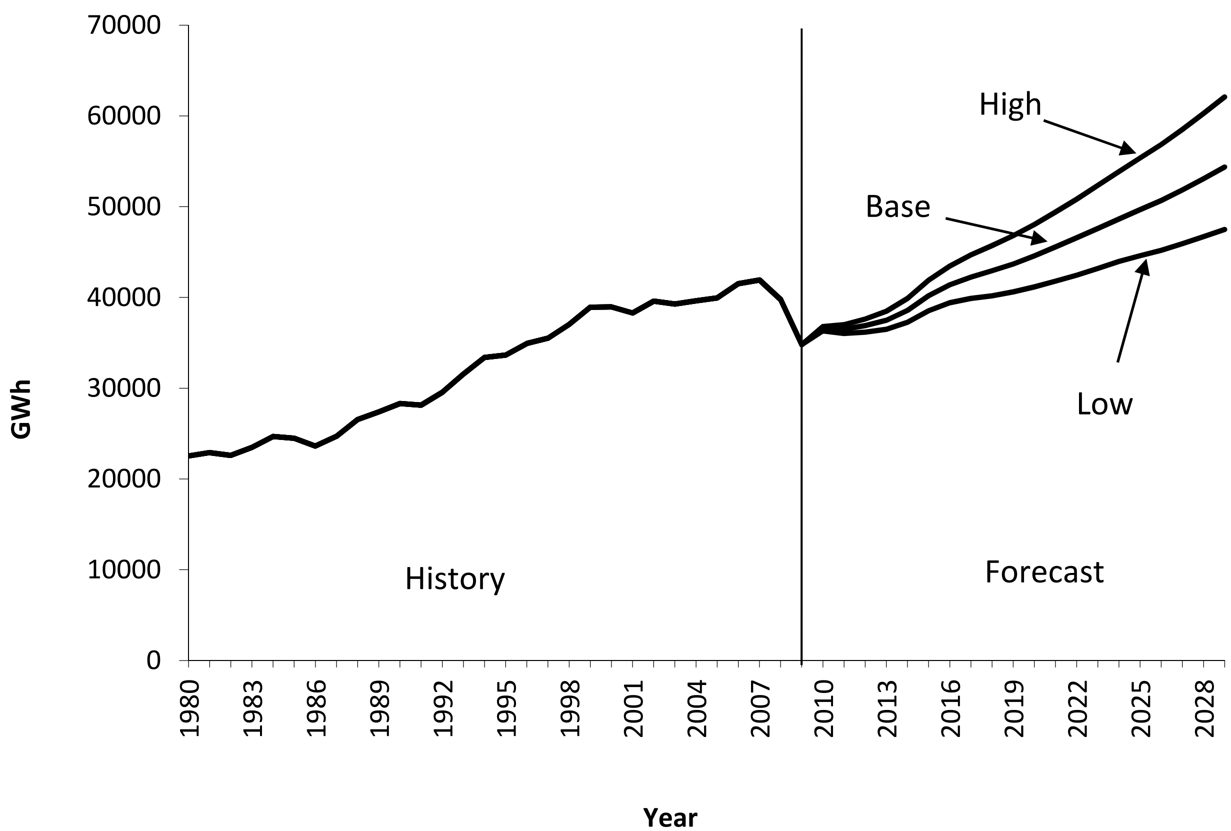
Table 7-4. History of SUFG Industrial Sector Growth Rates (Percent)

Forecast	Output	Mix Effects	Electric Energy-weighted Output	Prior to DSM		After DSM	
				Intensity	Sales Growth	Intensity	Sales Growth
2011 SUFG Base (2010-2029)	3.95	-1.11	2.84	-0.68	2.16	-0.68	2.11
2009 SUFG Base (2008-2027)	2.82	-0.56	2.26	-0.63	1.63	-0.63	1.63
2007 SUFG Base (2006-2025)	3.48	-0.39	3.09	-0.42	2.67	-0.42	2.67

Table 7-5. Indiana Industrial Electricity Sales Average Compound Growth Rates by Scenario (Percent)

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2010-29	2.11	1.42	2.79

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



Note: See the Appendix to this report for historical and projected values.

Indiana Industrial Electricity Price Projections

Historical values and current projections of industrial electricity prices are shown in Table 7-6 and Figure 7-5. In real terms, industrial electricity prices declined from the mid-1980s until 2002. Real industrial electricity prices have risen since 2002 due to increases in fuel costs and the installation of new emissions control equipment. SUFG projects real industrial electricity prices to rise through the entire forecast horizon with the need for additional emissions control equipment and additional supply/demand resources. SUFG's real price projections for the individual IOUs follow the same patterns as the state as a whole, but there are variations across the utilities. Historical and forecast prices are included in the Appendix of this report.

Figure 7-5. Indiana Industrial Base Real Price Projections (in 2009 Dollars)

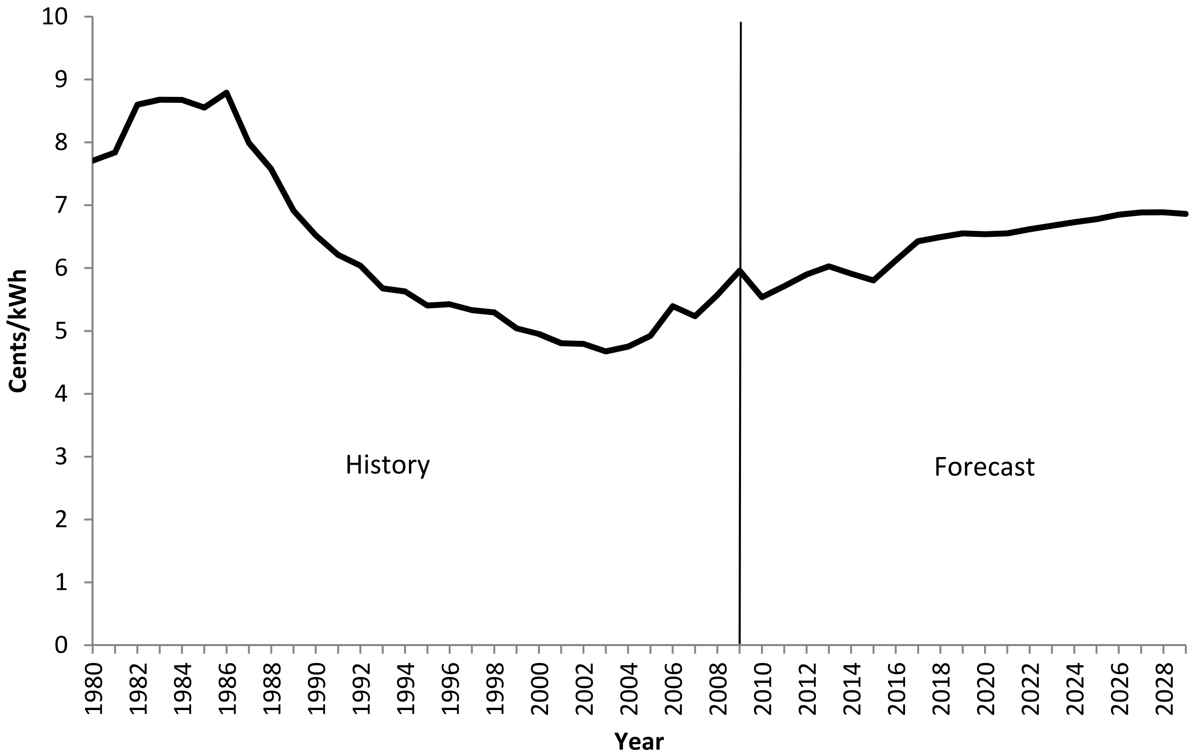


Table 7-6. Indiana Industrial Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	**Percent**
1980-1985	2.11
1985-1990	-5.28
1990-1995	-3.69
1995-2000	-1.73
2000-2005	-0.12
2005-2009	4.89
2010-2029	1.14

Note: See the Appendix to this report for historical and projected values and an explanation of how SUFG arrives at these numbers.

Chapter 8

Proposed Environmental Regulations

Overview

The U.S. Environmental Protection Agency (EPA) is developing a number of environmental regulations that are likely to have a significant effect on Indiana's electricity generation sector, particularly in terms of coal-fired generation. These rules are not included in this forecast due to the considerable uncertainty over the form and timing of the regulations. SUFG will be performing a separate study examining the expected impacts of these rules, with an expected release in the fall of 2011. This section briefly covers the different rules and looks at some of the characteristics of Indiana's coal-fired generation fleet that may impact its vulnerability to the regulations.

Cross-State Air Pollution Rule

Finalized in July 2011 (after the inputs to the SUFG modeling system for this forecast were finalized) under the Clean Air Act, this rule affects 27 states including Indiana, requiring reductions in sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions beginning in 2012, with stricter reductions in 2014. It establishes an SO_2 emissions cap that is considerably smaller for Indiana (43.6 percent lower in 2014 than in 2012) and limits the trading region by separating affected states into two groups with no trading between the groups. It replaces the Clean Air Interstate Rule. A second version of the rule is expected to be proposed in 2011 and finalized in the summer of 2012.

Mercury and Air Toxics Standards (MATS)

Proposed under the Clean Air Act, this rule would limit emissions from mercury, acid gases, and other pollutants from power plants. It would prevent 91 percent of the mercury in coal from being released. The rule would replace the court-vacated Clean Air Mercury Rule. It was proposed in May 2011, with comments accepted until August 2011. The final rule is expected in November 2011.

Greenhouse Gases

To be proposed under the Clean Air Act, this rule would establish performance standards for new and modified generating units, along with emissions guidelines for existing generating units. The proposed rule is expected in September 2011 and the final rule is expected in May 2012.

Cooling Water Intake Structures

Proposed under section §316(b) of the Clean Water Act , the rule is intended to reduce damage to aquatic life through impingement, when the organisms are trapped against inlet screens, or entrainment, when they are drawn into the generator's cooling water system. Facilities that withdraw at least 2 million gallons per day would be subject to a limit on the number of fish that can be killed through impingement. Facilities that withdraw at least 125 million gallons per day and new units at existing facilities may be subject to additional restrictions. The rule was proposed in April 2011, with comments accepted until August 2011 and a final rule expected in July 2012.

Coal Combustion Residuals

Two options were proposed under the Resource Conservation and Recovery Act: (1) list residuals as special wastes when destined for disposal in landfills or surface impoundments and (2) regulate as a non-hazardous waste. The proposed rule was released in June 2010, and comments were received through November 2010. EPA has not yet announced an expected date for the release of the final rule.

Characteristics of Indiana's Coal-fired Generation Fleet

The vulnerability of a particular generating unit to the various potential environmental regulations depends on a number of factors. These factors include the age, size, efficiency and operating condition of the unit; any existing emissions controls device that may be installed; the type of cooling system and ash disposal used by the facility; and physical characteristics of the site (e.g., space availability for installation of new equipment). While an older, less efficient generator without an SO2 removal system may be a candidate for retirement under a new set of regulations, a newer larger unit with a flue gas desulfurization (FGD) system may be a candidate for additional pollution controls and continue to operate.

SUFG has collected information on the status of pollution control devices, cooling water systems, and ash disposal systems from utility filings with EIA. Since these filings are somewhat dated and SUFG has not yet verified the information with the utilities, this information is summarized here only to provide a sense of the status of the coal-fired generation fleet.

The age of the coal fleet is illustrated in Figure 8-1. About 9 percent of the generating capacity (in MW) was installed before 1960 and about 27 percent dates to pre-1970. As shown in Figure 8-2, 43 percent of Indiana's coal-fired generating capacity has some form of FGD system installed. Figure 8-3 shows similar information for selective catalytic reduction (SCR) systems for NOx removal. While other generators have other forms of NOx control devices installed, SCRs are illustrated here because the new regulations are expected to push the industry toward SCRs. There are also facilities in various stages of the approval and construction process for installing FGDs and SCRs. These retrofits are not reflected in the figures.

Figure 8-1. Vintage of Indiana's Coal-fired Generating Fleet

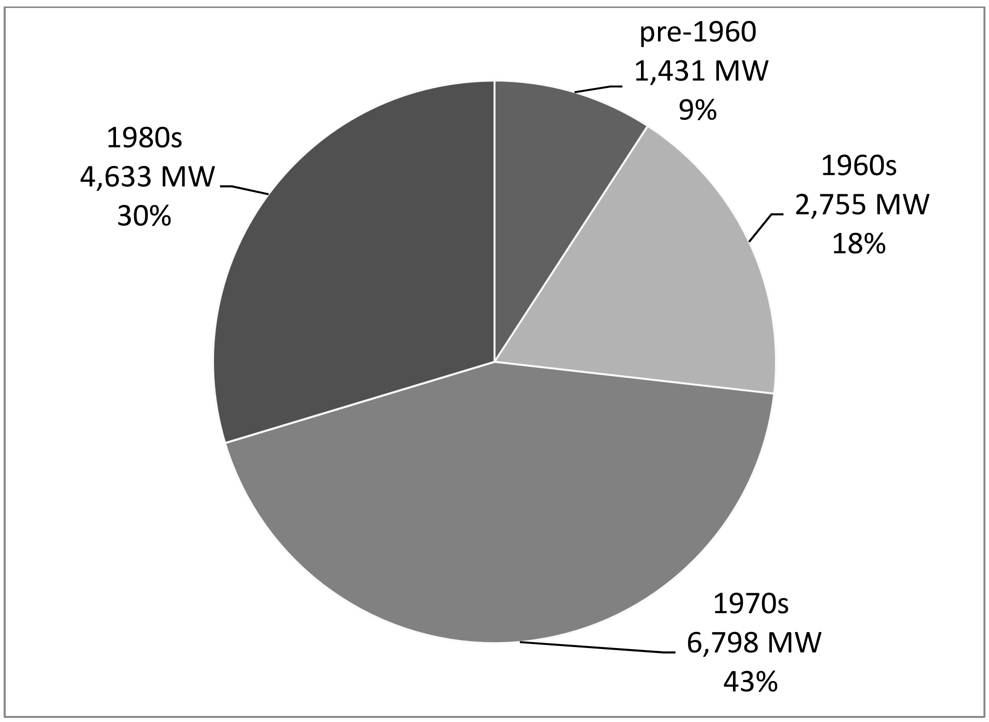


Figure 8-2. Installation of FGDs in Indiana's Coal-fired Generating Fleet

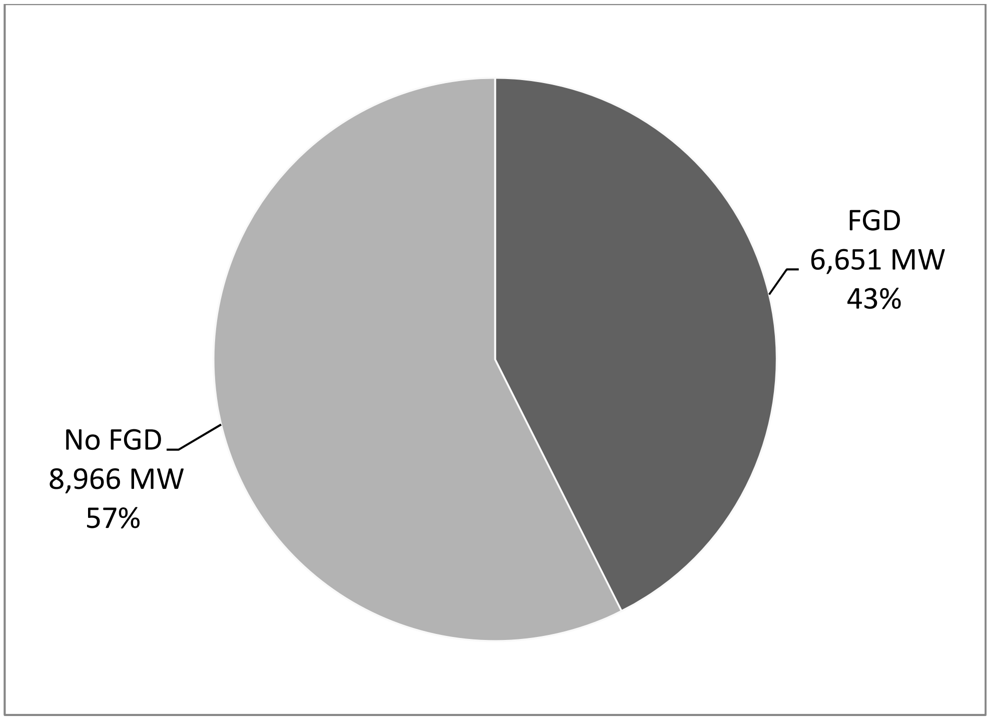
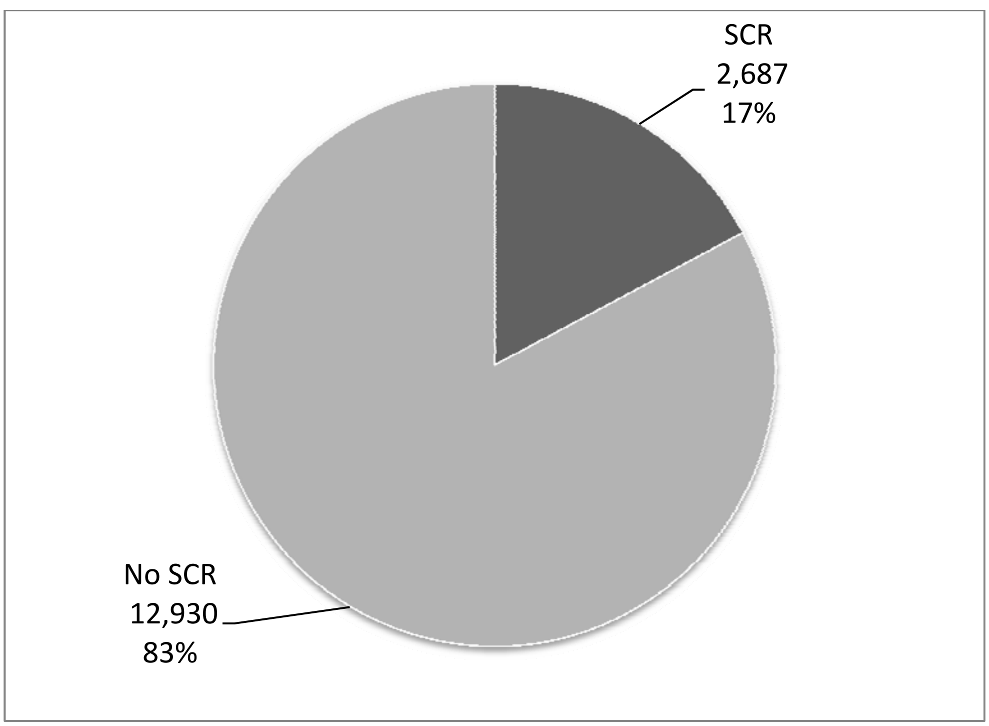


Figure 8-3. Installation of SCRs in Indiana's Coal-fired Generating Fleet



Appendix

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

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 are 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.

Indiana Michigan Power Company (I&M), Wabash Valley Power Association (WVPA), Indiana Municipal Power Agency (IMPA), and Hoosier Energy serve load outside of the state which SUFG excluded in developing projections for Indiana. Slightly less than 20 percent of I&M's load is in Michigan and while the majority of WVPA's load is in Indiana, it does have members in Illinois, Michigan, Missouri, and Ohio. IMPA has a wholesale member in Ohio and Hoosier Energy recently acquired a member cooperative in Illinois. These utilities 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 directly 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 rural electric membership cooperatives (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 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 on 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 Hoosier Energy, IMPA and WVPA.

Statewide summer peak demand may not be obtained by simply adding across utilities because of diversity. 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. To obtain an estimate of statewide peak demand, the summer peak demand estimates for the individual utilities are added together and adjusted for diversity.

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 detail. However, the not-for-profit utilities were able to provide SUFG with a breakdown of member load by sector.

SUFG feels relatively comfortable with these estimates, but is concerned about the future availability of detailed sector-specific data. If data proves to be unavailable 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 2011 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	1982	19927	13725	22600	696	56948	3986	60934	10683
Hist	1983	19950	13665	23476	626	57717	4040	61757	11744
Hist	1984	20153	14274	24678	674	59779	4185	63964	11331
Hist	1985	19707	14651	24480	653	59491	4164	63655	11030
Hist	1986	20410	15429	23618	610	60067	4205	64271	11834
Hist	1987	21154	16144	24694	617	62609	4383	66992	12218
Hist	1988	22444	16808	26546	633	66431	4650	71081	13447
Hist	1989	22251	17205	27394	661	67511	4726	72237	12979
Hist	1990	22037	17659	28311	650	68657	4806	73463	13659
Hist	1991	24215	18580	28141	629	71564	5009	76573	14278
Hist	1992	22916	18556	29540	619	71632	5014	76646	14055
Hist	1993	25060	19627	31562	511	76760	5373	82133	14916
Hist	1994	25176	20116	33395	507	79193	5544	84737	15010
Hist	1995	26510	20646	33659	510	81326	5693	87019	16251
Hist	1996	26833	20909	34920	536	83197	5824	89021	16181
Hist	1997	26792	21295	35499	859	84445	5911	90356	16040
Hist	1998	27663	22166	37012	899	87740	6142	93881	16657
Hist	1999	29180	23078	38916	960	92134	6449	98584	17266
Hist	2000	28684	23721	38957	1012	92373	6466	98839	16757
Hist	2001	29437	23953	38293	987	92670	6487	99157	17531
Hist	2002	32363	24980	39594	1025	97961	6857	104818	18851
Hist	2003	31177	24940	39285	981	96383	6747	103130	18843
Hist	2004	31654	25411	39634	1088	97787	6845	104632	18254
Hist	2005	34058	26905	39940	1021	101924	7135	109058	19819
Hist	2006	32694	26898	41516	1009	102116	7148	109264	20921
Hist	2007	35197	27827	41920	1064	106008	7421	113428	20849
Hist	2008	34360	27635	39762	1088	102845	7199	110044	19257
Hist	2009	33045	26339	34804	1081	95269	6669	101938	18975
Frcst	2010	34470	26806	36554	1081	98911	7237	106148	19269
Frcst	2011	34726	27120	36511	1081	99437	7268	106706	19481
Frcst	2012	34898	27445	36891	1081	100315	7323	107638	19654
Frcst	2013	35093	27703	37480	1081	101357	7388	108745	19881
Frcst	2014	35313	28117	38567	1081	103078	7501	110579	20203
Frcst	2015	35745	28469	40195	1081	105490	7663	113152	20650
Frcst	2016	35841	28798	41391	1081	107110	7770	114880	20935
Frcst	2017	35962	29045	42243	1081	108330	7852	116182	21141
Frcst	2018	36050	29302	42938	1081	109370	7916	117287	21319
Frcst	2019	36216	29552	43689	1081	110538	7994	118532	21520
Frcst	2020	36831	29727	44581	1081	112220	8110	120330	21841
Frcst	2021	36955	29922	45576	1081	113534	8202	121736	22026
Frcst	2022	37137	30074	46574	1081	114866	8297	123163	22277
Frcst	2023	37316	30245	47599	1081	116239	8398	124638	22528
Frcst	2024	37568	30440	48645	1081	117734	8511	126245	22810
Frcst	2025	38033	30616	49678	1081	119407	8638	128045	23140
Frcst	2026	38396	30870	50679	1081	121026	8763	129788	23454
Frcst	2027	38754	31128	51841	1081	122804	8900	131703	23798
Frcst	2028	39098	31410	53081	1081	124669	9043	133712	24152
Frcst	2029	39428	31714	54362	1081	126584	9192	135776	24521

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1980-1985	3.48	3.36	1.66	3.27	2.68	2.68	2.68	-0.45
1985-1990	2.26	3.81	2.95	-0.09	2.91	2.91	2.91	4.37
1990-1995	3.77	3.17	3.52	-4.74	3.44	3.44	3.44	3.54
1995-2000	1.59	2.82	2.97	14.69	2.58	2.58	2.58	0.61
2000-2005	3.49	2.55	0.50	0.17	1.99	1.99	1.99	3.41
2005-2010	0.24	-0.07	-1.76	1.15	-0.60	0.28	-0.54	-0.56
2010-2015	0.73	1.21	1.92	0.00	1.30	1.15	1.29	1.39
2015-2020	0.60	0.87	2.09	0.00	1.24	1.14	1.24	1.13
2020-2025	0.64	0.59	2.19	0.00	1.25	1.27	1.25	1.16
2025-2029	0.90	0.89	2.28	0.00	1.47	1.57	1.48	1.46
2010-2029	0.71	0.89	2.11	0.00	1.31	1.27	1.30	1.28

SUFG 2011 Low Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales						Energy	Summer
		Res	Com	Ind	Other	Total	Losses	Required	Demand
Hist	1982	19927	13725	22600	696	56948	3986	60934	10683
Hist	1983	19950	13665	23476	626	57717	4040	61757	11744
Hist	1984	20153	14274	24678	674	59779	4185	63964	11331
Hist	1985	19707	14651	24480	653	59491	4164	63655	11030
Hist	1986	20410	15429	23618	610	60067	4205	64271	11834
Hist	1987	21154	16144	24694	617	62609	4383	66992	12218
Hist	1988	22444	16808	26546	633	66431	4650	71081	13447
Hist	1989	22251	17205	27394	661	67511	4726	72237	12979
Hist	1990	22037	17659	28311	650	68657	4806	73463	13659
Hist	1991	24215	18580	28141	629	71564	5009	76573	14278
Hist	1992	22916	18556	29540	619	71632	5014	76646	14055
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Hist	1997	26792	21295	35499	859	84445	5911	90356	16040
Hist	1998	27663	22166	37012	899	87740	6142	93881	16657
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Hist	2000	28684	23721	38957	1012	92373	6466	98839	16757
Hist	2001	29437	23953	38293	987	92670	6487	99157	17531
Hist	2002	32363	24980	39594	1025	97961	6857	104818	18851
Hist	2003	31177	24940	39285	981	96383	6747	103130	18843
Hist	2004	31654	25411	39634	1088	97787	6845	104632	18254
Hist	2005	34058	26905	39940	1021	101924	7135	109058	19819
Hist	2006	32694	26898	41516	1009	102116	7148	109264	20921
Hist	2007	35197	27827	41920	1064	106008	7421	113428	20849
Hist	2008	34360	27635	39762	1088	102845	7199	110044	19257
Hist	2009	33045	26339	34804	1081	95269	6669	101938	18975
Frcst	2010	34470	26806	36311	1081	98668	7219	105888	19226
Frcst	2011	34725	27117	36031	1081	98954	7233	106186	19396
Frcst	2012	34879	27443	36166	1081	99568	7269	106837	19522
Frcst	2013	35072	27684	36499	1081	100336	7314	107650	19701
Frcst	2014	35283	28081	37274	1081	101719	7402	109122	19963
Frcst	2015	35715	28408	38539	1081	103743	7536	111279	20341
Frcst	2016	35792	28710	39411	1081	104994	7617	112611	20560
Frcst	2017	35895	28926	39900	1081	105801	7670	113471	20692
Frcst	2018	35957	29147	40173	1081	106358	7700	114058	20784
Frcst	2019	36097	29359	40619	1081	107155	7751	114906	20917
Frcst	2020	36718	29501	41162	1081	108461	7840	116301	21171
Frcst	2021	36820	29659	41791	1081	109352	7901	117252	21280
Frcst	2022	36983	29774	42449	1081	110286	7966	118253	21459
Frcst	2023	37144	29917	43182	1081	111324	8041	119365	21650
Frcst	2024	37386	30080	43958	1081	112505	8128	120633	21874
Frcst	2025	37840	30216	44601	1081	113738	8221	121959	22126
Frcst	2026	38190	30440	45182	1081	114892	8312	123204	22357
Frcst	2027	38523	30662	45916	1081	116182	8411	124593	22609
Frcst	2028	38850	30911	46694	1081	117537	8516	126053	22869
Frcst	2029	39168	31185	47494	1081	118928	8625	127553	23141

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1980-1985	3.48	3.36	1.66	3.27	2.68	2.68	2.68	-0.45
1985-1990	2.26	3.81	2.95	-0.09	2.91	2.91	2.91	4.37
1990-1995	3.77	3.17	3.52	-4.74	3.44	3.44	3.44	3.54
1995-2000	1.59	2.82	2.97	14.69	2.58	2.58	2.58	0.61
2000-2005	3.49	2.55	0.50	0.17	1.99	1.99	1.99	3.41
2005-2010	0.24	-0.07	-1.89	1.15	-0.65	0.24	-0.59	-0.61
2010-2015	0.71	1.17	1.20	0.00	1.01	0.86	1.00	1.13
2015-2020	0.56	0.76	1.33	0.00	0.89	0.79	0.89	0.80
2020-2025	0.60	0.48	1.62	0.00	0.95	0.96	0.95	0.89
2025-2029	0.87	0.79	1.58	0.00	1.12	1.21	1.13	1.13
2010-2029	0.67	0.80	1.42	0.00	0.99	0.94	0.98	0.98

SUFG 2011 High Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales						Energy	Summer
		Res	Com	Ind	Other	Total	Losses	Required	Demand
Hist	1982	19927	13725	22600	696	56948	3986	60934	10683
Hist	1983	19950	13665	23476	626	57717	4040	61757	11744
Hist	1984	20153	14274	24678	674	59779	4185	63964	11331
Hist	1985	19707	14651	24480	653	59491	4164	63655	11030
Hist	1986	20410	15429	23618	610	60067	4205	64271	11834
Hist	1987	21154	16144	24694	617	62609	4383	66992	12218
Hist	1988	22444	16808	26546	633	66431	4650	71081	13447
Hist	1989	22251	17205	27394	661	67511	4726	72237	12979
Hist	1990	22037	17659	28311	650	68657	4806	73463	13659
Hist	1991	24215	18580	28141	629	71564	5009	76573	14278
Hist	1992	22916	18556	29540	619	71632	5014	76646	14055
Hist	1993	25060	19627	31562	511	76760	5373	82133	14916
Hist	1994	25176	20116	33395	507	79193	5544	84737	15010
Hist	1995	26510	20646	33659	510	81326	5693	87019	16251
Hist	1996	26833	20909	34920	536	83197	5824	89021	16181
Hist	1997	26792	21295	35499	859	84445	5911	90356	16040
Hist	1998	27663	22166	37012	899	87740	6142	93881	16657
Hist	1999	29180	23078	38916	960	92134	6449	98584	17266
Hist	2000	28684	23721	38957	1012	92373	6466	98839	16757
Hist	2001	29437	23953	38293	987	92670	6487	99157	17531
Hist	2002	32363	24980	39594	1025	97961	6857	104818	18851
Hist	2003	31177	24940	39285	981	96383	6747	103130	18843
Hist	2004	31654	25411	39634	1088	97787	6845	104632	18254
Hist	2005	34058	26905	39940	1021	101924	7135	109058	19819
Hist	2006	32694	26898	41516	1009	102116	7148	109264	20921
Hist	2007	35197	27827	41920	1064	106008	7421	113428	20849
Hist	2008	34610	27120	42182	1088	102845	7719	110044	19257
Hist	2009	35194	27216	40176	1081	95269	7619	101938	18975
Frcst	2010	34470	26806	36798	1081	99155	7255	106410	19311
Frcst	2011	34726	27120	36996	1081	99923	7304	107227	19566
Frcst	2012	34900	27446	37628	1081	101054	7377	108431	19783
Frcst	2013	35095	27707	38481	1081	102364	7461	109825	20057
Frcst	2014	35336	28144	39895	1081	104456	7602	112058	20446
Frcst	2015	35774	28520	41907	1081	107282	7792	115074	20965
Frcst	2016	35882	28879	43461	1081	109303	7928	117231	21322
Frcst	2017	36007	29157	44683	1081	110927	8040	118967	21601
Frcst	2018	36108	29447	45716	1081	112351	8133	120484	21848
Frcst	2019	36283	29729	46800	1081	113893	8239	122131	22115
Frcst	2020	36899	29939	48046	1081	115964	8383	124347	22504
Frcst	2021	37038	30164	49408	1081	117691	8506	126197	22764
Frcst	2022	37238	30345	50824	1081	119488	8636	128124	23098
Frcst	2023	37437	30556	52341	1081	121416	8777	130193	23449
Frcst	2024	37701	30783	53855	1081	123420	8928	132348	23824
Frcst	2025	38178	30991	55366	1081	125616	9094	134709	24250
Frcst	2026	38557	31276	56851	1081	127765	9258	137024	24664
Frcst	2027	38928	31568	58515	1081	130092	9435	139528	25106
Frcst	2028	39284	31881	60274	1081	132519	9621	142140	25563
Frcst	2029	39623	32224	62084	1081	135012	9811	144823	26034

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1980-1985	3.48	3.36	1.66	3.27	2.68	2.68	2.68	-0.45
1985-1990	2.26	3.81	2.95	-0.09	2.91	2.91	2.91	4.37
1990-1995	3.77	3.17	3.52	-4.74	3.44	3.44	3.44	3.54
1995-2000	1.59	2.82	2.97	14.69	2.58	2.58	2.58	0.61
2000-2005	3.49	2.55	0.50	0.17	1.99	1.99	1.99	3.41
2005-2010	0.24	-0.07	-1.63	1.15	-0.55	0.33	-0.49	-0.52
2010-2015	0.75	1.25	2.63	0.00	1.59	1.44	1.58	1.66
2015-2020	0.62	0.98	2.77	0.00	1.57	1.47	1.56	1.43
2020-2025	0.68	0.69	2.88	0.00	1.61	1.64	1.61	1.51
2025-2029	0.93	0.98	2.90	0.00	1.82	1.92	1.83	1.79
2010-2029	0.74	0.97	2.79	0.00	1.64	1.60	1.64	1.58

Indiana Base Average Retail Rates (Cents/kWh) (in 2009 Dollars)

Year	Res	Com	Ind	Average
1982	11.86	11.67	8.60	10.42
1983	12.34	11.81	8.68	10.59
1984	12.45	11.85	8.67	10.61
1985	12.75	11.81	8.55	10.64
1986	12.91	12.14	8.79	10.96
1987	12.45	11.81	7.99	10.37
1988	11.71	10.80	7.58	9.68
1989	10.94	9.26	6.91	8.72
1990	10.31	8.72	6.52	8.19
1991	9.67	8.19	6.21	7.80
1992	9.58	8.08	6.04	7.60
1993	9.04	7.59	5.68	7.17
1994	9.07	7.57	5.63	7.11
1995	8.91	7.50	5.40	6.98
1996	8.88	7.47	5.42	6.95
1997	9.04	7.38	5.33	6.92
1998	9.06	7.37	5.30	6.90
1999	8.79	7.20	5.04	6.67
2000	8.43	6.83	4.95	6.42
2001	8.26	6.87	4.80	6.35
2002	8.09	6.79	4.80	6.30
2003	8.06	6.70	4.68	6.21
2004	8.10	6.80	4.75	6.29
2005	8.10	6.74	4.92	6.39
2006	8.68	7.48	5.39	6.91
2007	8.32	7.24	5.23	6.72
2008	8.61	7.30	5.57	6.98
2009	9.15	7.74	5.96	7.49
2010	8.74	7.87	5.54	7.23
2011	9.26	8.15	5.71	7.56
2012	9.82	8.47	5.90	7.90
2013	9.75	8.45	6.03	7.91
2014	9.78	8.34	5.91	7.82
2015	9.85	8.40	5.80	7.80
2016	10.53	8.98	6.12	8.27
2017	11.11	9.44	6.43	8.69
2018	11.22	9.54	6.49	8.76
2019	11.24	9.57	6.55	8.78
2020	11.19	9.52	6.54	8.74
2021	11.14	9.49	6.55	8.70
2022	11.09	9.47	6.62	8.69
2023	11.07	9.48	6.67	8.69
2024	11.06	9.49	6.73	8.70
2025	10.98	9.44	6.78	8.67
2026	10.97	9.45	6.85	8.69
2027	10.92	9.43	6.89	8.67
2028	10.84	9.38	6.89	8.63
2029	10.71	9.29	6.86	8.54
Average Compound Growth Rates (%)				
Year-Year	**Res**	**Com**	**Ind**	**Average**
1980-1985	4.00	1.23	2.11	2.50
1985-1990	-4.16	-5.88	-5.28	-5.09
1990-1995	-2.88	-2.98	-3.69	-3.16
1995-2000	-1.09	-1.85	-1.73	-1.66
2000-2005	-0.79	-0.26	-0.12	-0.09
2005-2010	1.53	3.15	2.38	2.51
2010-2015	2.42	1.31	0.95	1.51
2015-2020	2.57	2.53	2.41	2.32
2020-2025	-0.37	-0.17	0.72	-0.16
2025-2029	-0.62	-0.41	0.30	-0.39
2010-2029	1.08	0.87	1.14	0.88

Note: Energy Weighted Average Rates for Indiana IOUs
-Results for the low and high economic activity cases are similar and are not reported

List of Acronyms

ACGR	Average Compound Growth Rates
Btu	British thermal unit
CAIR	Clean Air Interstate Rule
CC	Combined Cycle
CEDMS	Commercial Energy Demand Modeling System
CEMR	Center for Econometric Model Research
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
DOE	U. S. Department of Energy
DSM	Demand-Side Management
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
GDP	Gross Domestic Product
GSP	Gross State Product
GWh	Gigawatthour
HVAC	Heating, Ventilation and Air Conditioning
I&M	Indiana Michigan Power Company
IBRC	Indiana Business Research Center
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
IURC	Indiana Utility Regulatory Commission
IMPA	Indiana Municipal Power Agency
KLEM	Capital, labor, energy and materials
kWh	Kilowatthour
LMSTM	Load Management Strategy Testing Model
LPG	Liquefied Petroleum Gas
MATS	Mercury and Air Toxics Standards
MW	Megawatt
NAICS	North American Industry Classification System
NFP	Not-for-Profit
OPEC	Organization of Petroleum Exporting Countries
ORNL	Oak Ridge National Labs
PC	Pulverized Coal-Fired
REMC	Rural Electric Membership Cooperative
REDMS	Residential Energy Modeling System
REEMS	Residential End-Use Energy Modeling System
RTO	Regional Transmission Organization
RUS	U.S. Department of Agriculture Rural Utilities Service
SCR	Selective Catalytic Reduction
SIC	Standard Industrial Classification
SUFG	State Utility Forecasting Group
WVPA	Wabash Valley Power Association