Indiana Electricity Projections:
The 2013 Forecast

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This report is dedicated to the memory of Forrest Holland. Forrest was an integral part of the State Utility Forecasting Group since its inception. He was truly a gentleman and a scholar and was an irreplaceable asset to the State of Indiana. Most of all, he was a friend.

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Foreword

This report presents the 2013 projections of future electricity requirements for the state of Indiana for the period 2012-2031. 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 fourteenth 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 fourteenth 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 2016 unless additional plant retirements occur before then.

This forecast projects electricity usage to grow at a rate of 0.74 percent per year over the 20 years of the forecast. This growth rate is considerably lower than Indiana has historically experienced and lower than the 2011 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: utility-sponsored conservation efforts, higher projected electricity prices making investments in higher efficiency equipment more cost-effective, and stricter federal energy efficiency standards. Peak electricity demand is projected to grow at an average rate of 0.90 percent annually. This corresponds to about 170 megawatts (MW) of increased peak demand per year.

The 2013 forecast predicts Indiana electricity prices to continue to rise in real (inflation adjusted) terms through 2023 and then level off through the remainder of the forecast period. The price increase is caused by three factors; costs associated with meeting environmental rules, costs associated with recent plant construction, and costs associated with extending the life of existing generating facilities. While the price forecast is considerably higher than in the 2011 forecast, it is similar to the SUFG's supplemental study released in January 2012, which examined the impact of future potential EPA regulations. The final rules for some of those regulations, particularly the Mercury and Air Toxics Standards, have been released. Finalized regulations are included in the forecast and they put significant upward pressure on the price projections.

As in the previous three 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 320 MW of peaking, 310 MW of cycling, and 650 MW of baseload resources by 2020. These requirements are roughly half those identified in the 2011 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 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/discoverypark/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.

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. 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 18.3 percent. This represents a slightly higher reserve margin than the 15.8 and 16.3 percent figures used in the 2011 and 2009 forecasts respectively, due to changing regional transmission organization (RTO) requirements.

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 2013 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 0.90 percent growth per year over the forecast period. Indiana total employment is projected to grow at an average annual rate of 0.88 percent.

Other key economic projections are:

- Real personal income (a residential sector model driver) is expected to grow at a 2.15 percent annual rate.
- Non-manufacturing employment (the commercial sector model driver) is expected to average a 0.97 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 3.58 percent annual rate as gains in productivity outpace slight gains in employment.

[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. An 18.3 percent reserve margin is equivalent to a 15.5 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.

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 0.51 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 1.17 percent over the forecast period.

Fossil Fuel Price Projections

SUFG's current assumptions are based on the April 2013 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 prices decreased significantly in 2009 coming off of the high prices of 2008. Prices then rebounded somewhat in 2010 before declining again through 2012. They are projected to remain relatively constant through 2015, with a general 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 gigawatt-hours (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 0.74 percent, while the growth rate for peak demand is 0.90 percent. The growth rates in the previous forecast for electricity requirements and peak demand were 1.30 and 1.28 percent, respectively.

The growth within sectors varies 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 sector 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 170 MW.

Table 1-1. Annual Electricity Sales Growth (Percent) by Sector (Current Forecast vs. 2011 Projections)

Sector	Current (2012-2031)	2011 (2011-2029)
Residential	0.37	0.71
Commercial	0.33	0.89
Industrial	1.29	2.11
Total	0.74	1.30

Resource Implications

SUFG's resource plans include both demand-side and supply-side resources to meet forecast demand. Utility-sponsored energy efficiency and demand response[4] loads are netted from the demand projection and supply-side resources are added as necessary to maintain an 18.3 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).

[4] Demand response includes loads that can be interrupted by the utility during times of high system demand, generation shortages, or high wholesale market prices. They include direct load control and loads under industrial interruptible rates.

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

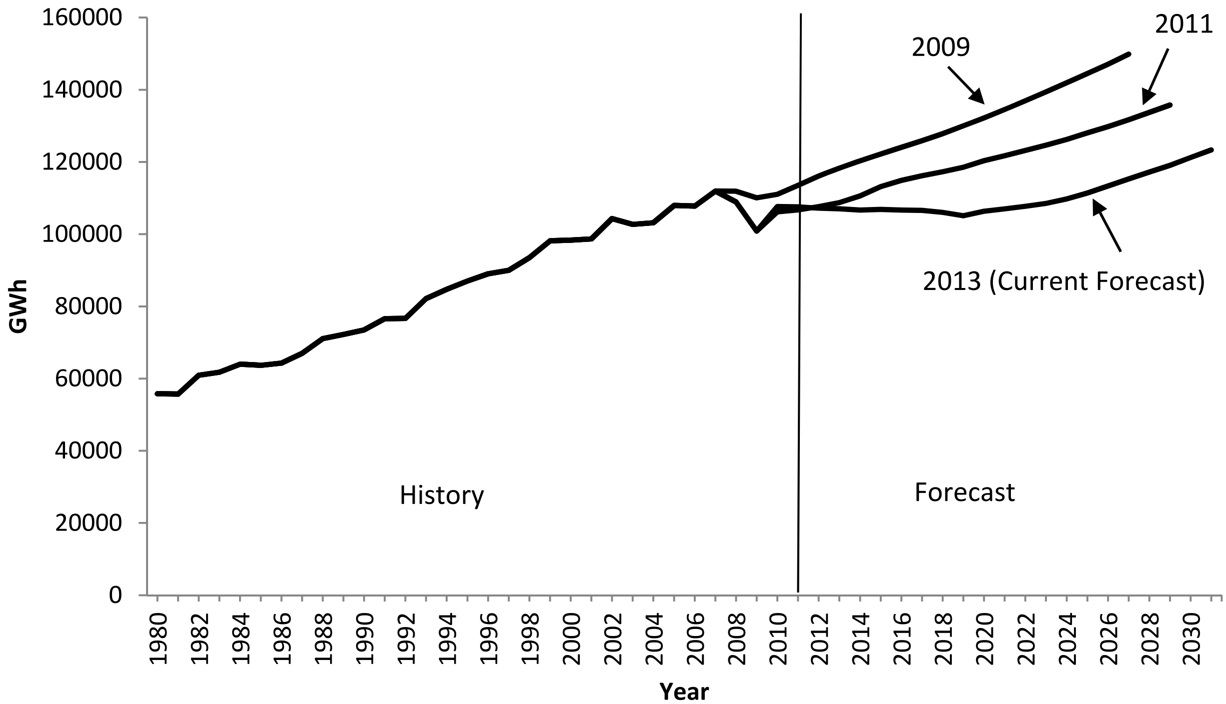
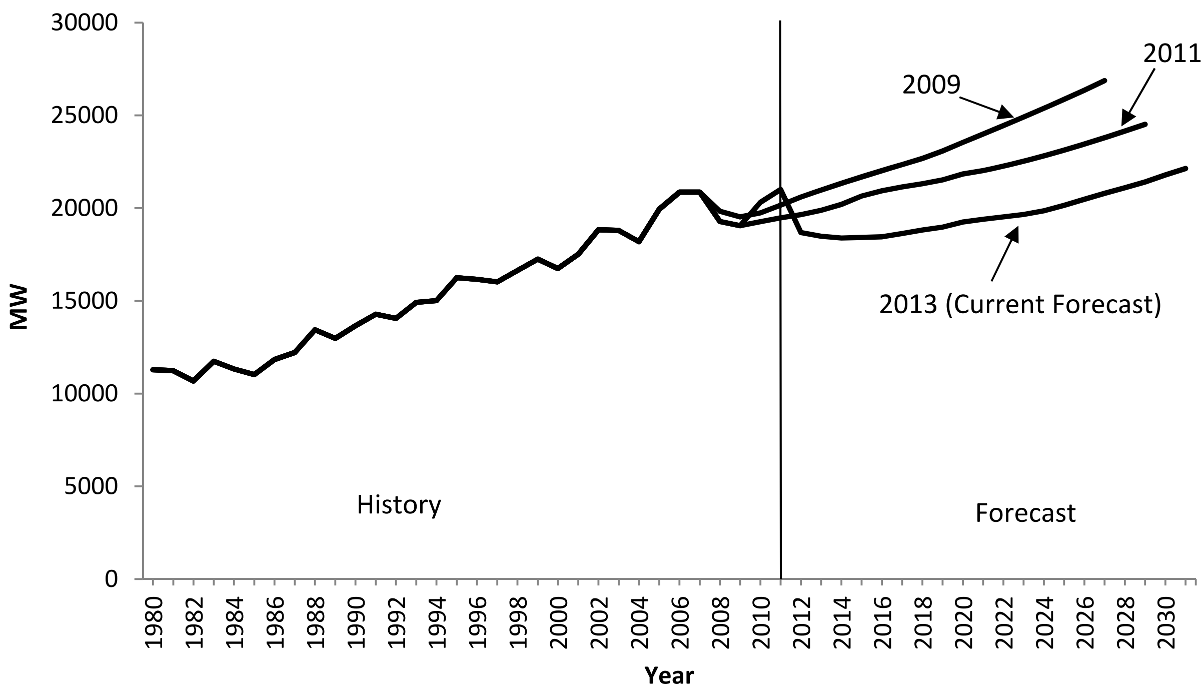


Figure 1-2. Indiana Peak Demand Requirements in MW (Historical, Current, and Previous Forecasts)



Demand-Side Resources

The current projection includes the energy and demand impacts of existing or planned utility-sponsored energy efficiency programs. Incremental energy efficiency programs, which include new programs and the expansion of existing programs, are projected to reduce peak demand by approximately 135 MW at the beginning of the forecast period and by about 1,800 MW at the end of the forecast. DSM projections were estimated from utility integrated resource plan filings, from information collected directly from the utilities by SUFG, or by SUFG based on rules established in December 2009 by the Indiana Utility Regulatory Commission (IURC).

These energy efficiency projections do not include the reductions in peak demand due to demand response. Demand response loads are projected to increase from 1,200 MW to about 1,420 MW over the forecast horizon. See Chapter 4 for additional information about DSM.

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. As of the time this forecast was produced, no decision had been made as to whether Duke Energy would retire Wabash River unit 6 or repower it to use natural gas. SUFG has modeled it as being retired in 2015 in this forecast. 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 18.3 percent reserve margin. Additionally, due to individual utilities having significantly different levels of reserves, small amounts of additional resources may be included to maintain individual utility reserve margins above 6 percent for modeling integrity purposes, even if the state as a whole is at or above the 18.3 percent threshold. This occurs through 2015 in this forecast.

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, 1,450 MW of additional resources are required. The net change in generation includes the retirement of units as reported in the utilities' 2011 Integrated Resource Plan (IRP) filings or as reported subsequently. Over the second half of the forecast period, an additional 3,600 MW of resources are required to maintain target reserves. If Duke Energy retrofits Wabash River 6, 318 fewer MW will be required.

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

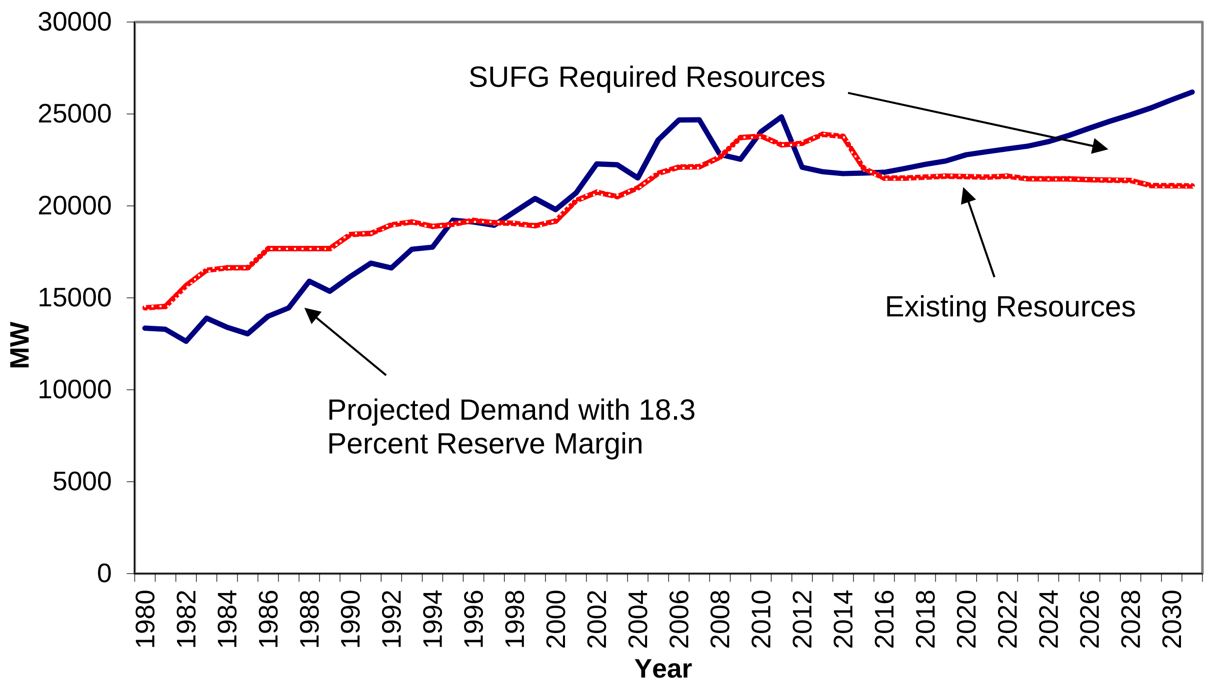


Table 1-2. Indiana Resource Plan in MW (SUFG Base)

	Uncontrolled Peak Demand[1]	Demand Response[2]	Net Peak Demand[3]	Existing/ Approved Capacity[4]	Incremental Change in Capacity[5]	Projected Additional Resource Requirements[6]				Total Resources[7]	Reserve Margin[8] (percent)
						Peaking	Cycling	Baseload	Total		
2011				23,326							
2012	19,888	1,205	18,683	23,406	80	20	80	20	120	23,526	26
2013	19,777	1,296	18,481	23,899	493	10	30	-	40	23,939	30
2014	19,718	1,329	18,389	23,781	-119	10	30	-	40	23,821	30
2015	19,769	1,357	18,412	22,034	-1747	20	50	-	70	22,104	20
2016	19,823	1,371	18,452	21,512	-523	130	160	120	410	21,922	19
2017	20,011	1,381	18,631	21,512	0	200	220	210	630	22,142	19
2018	20,208	1,390	18,818	21,568	56	190	240	460	890	22,458	19
2019	20,375	1,400	18,975	21,615	47	230	260	570	1,060	22,675	19
2020	20,663	1,407	19,256	21,590	-25	320	310	650	1,280	22,870	19
2021	20,814	1,414	19,401	21,569	-21	370	340	740	1,450	23,019	19
2022	20,944	1,416	19,528	21,619	50	390	360	790	1,540	23,159	19
2023	21,076	1,418	19,658	21,476	-143	480	420	920	1,820	23,296	19
2024	21,281	1,419	19,861	21,469	-7	510	480	1,060	2,050	23,519	18
2025	21,567	1,420	20,147	21,469	0	590	590	1,190	2,370	23,839	18
2026	21,896	1,420	20,476	21,428	-41	690	680	1,420	2,790	24,218	18
2027	22,222	1,420	20,801	21,400	-28	930	750	1,530	3,210	24,610	18
2028	22,520	1,421	21,099	21,381	-19	1,040	860	1,670	3,570	24,951	18
2029	22,833	1,421	21,413	21,108	-273	1,160	970	2,090	4,220	25,328	18
2030	23,210	1,421	21,790	21,093	-16	1,280	1,100	2,300	4,680	25,773	18
2031	23,558	1,421	22,138	21,085	-7	1,360	1,200	2,520	5,080	26,165	18

1 Uncontrolled peak demand is the peak demand prior to any load reduction from demand response programs being called upon.

2 Demand response is all the measures designed to shift load away from peak demand periods. These include interruptible and direct load control programs affecting peak demand.

3 Net peak demand is the peak demand after load reductions from demand response programs are taken into account.

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

5 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.

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

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

8 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.

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 was 2011. Therefore, 2012 and 2013 numbers represent projections. The resource requirements identified in Table 1-2 for 2012 and 2013 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 by 30 percent from 2012 to 2023 and then slowly decrease until 2026 before maintaining 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 Figure 1-4. The price projection labeled "2009" is the base from SUFG's 2009 forecast and the price projection labeled "2011" is the base case projection contained in SUFG's 2011 forecast. Figure 1-4 also shows the price trajectory for the supplemental analysis of potential EPA regulations that SUFG released in January 2012 (labeled "2011 w/ EPA"). For the prior price forecasts, SUFG rescaled the original price projections to 2011 dollars (from 2007 dollars for the 2009 projection, and from 2009 dollars for the 2011 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

Three major factors primarily determine the differences among the price projections in Figure 1-4: first, the cost of controlling emissions from coal-fired generation facilities to meet air emission standards; second, costs associated with resources required to meet future load; 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 Mercury and Air Toxics Standards (MATS) are included. The Cross-State Air Pollution Rule (CSAPR) was vacated by the D.C. Circuit Court and will be considered by the U.S. Supreme Court. Since CSAPR is currently vacated, it is not modeled but compliance with MATS largely implies compliance with CSAPR, so this has little effect. The generators that SUFG uses to approximate the costs of new resources are chosen to comply with the greenhouse gas rules for new plants. Other non-finalized rules, such as those affecting greenhouse gas emissions for existing generators, cooling water, and coal ash disposal are not included. SUFG produced a separate report that specifically addresses the impact of the various proposed and potential rules. This report was released in January 2012.

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 0.74, 0.29, and 1.17, 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.

Figure 1-4. Indiana Real Price Projections in cents/kWh (2011 Dollars) (Historical, Current and Previous Forecasts)

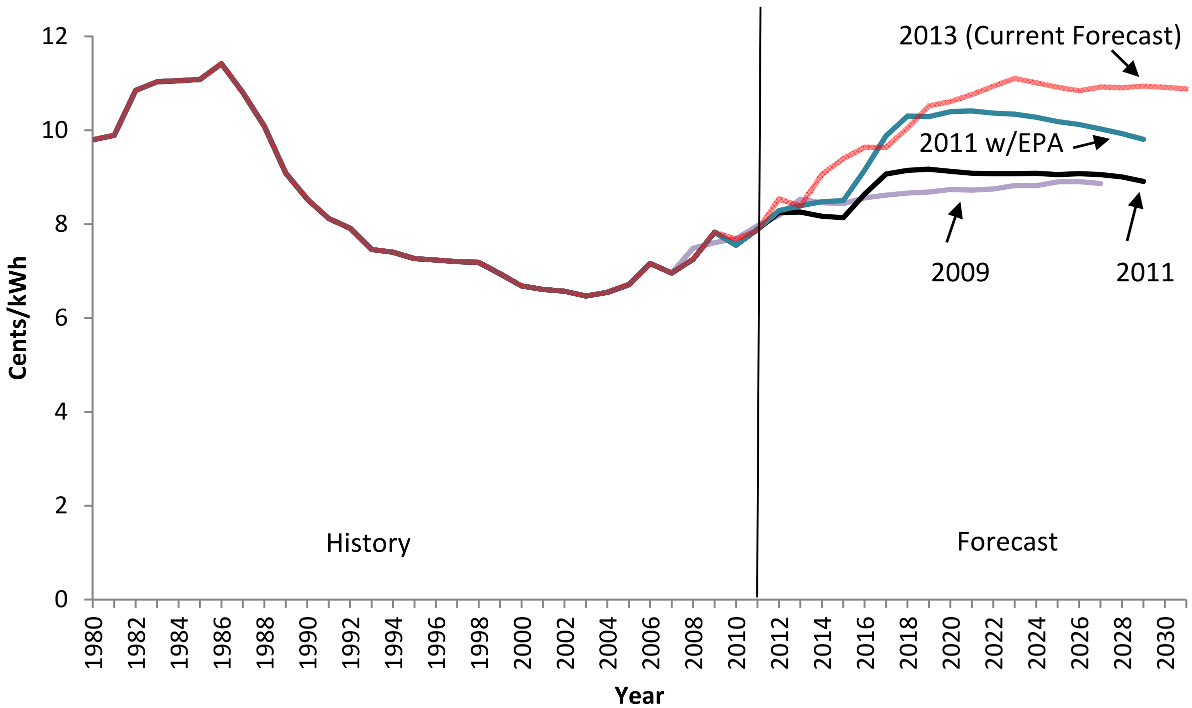
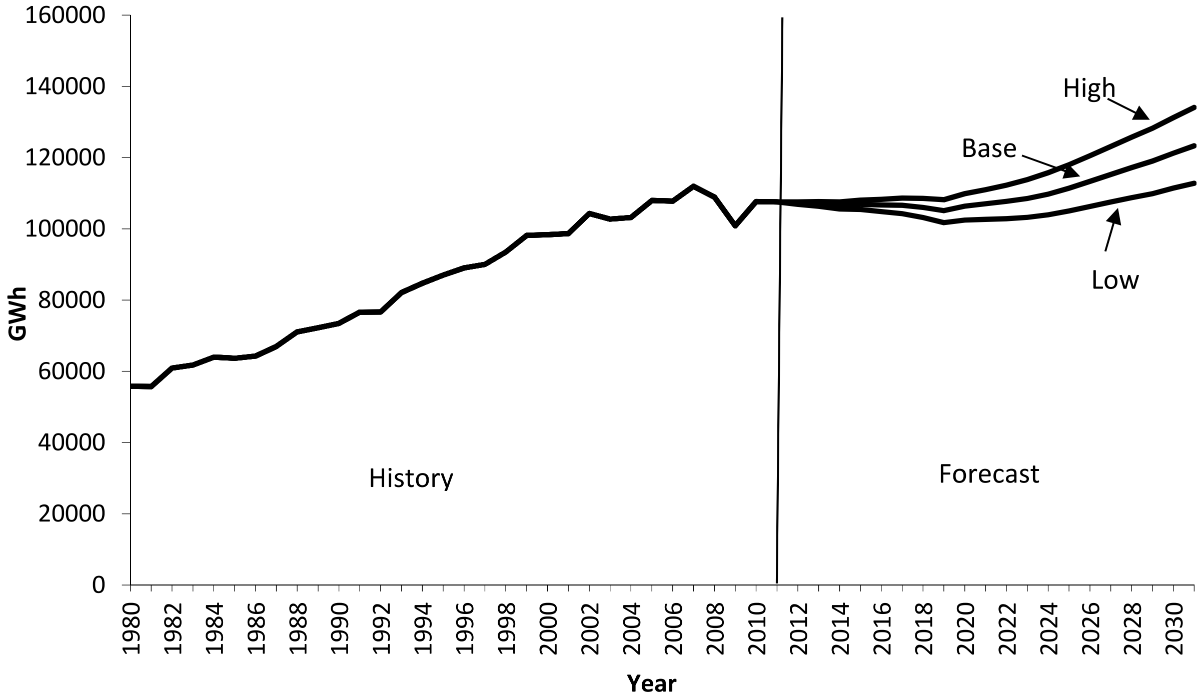


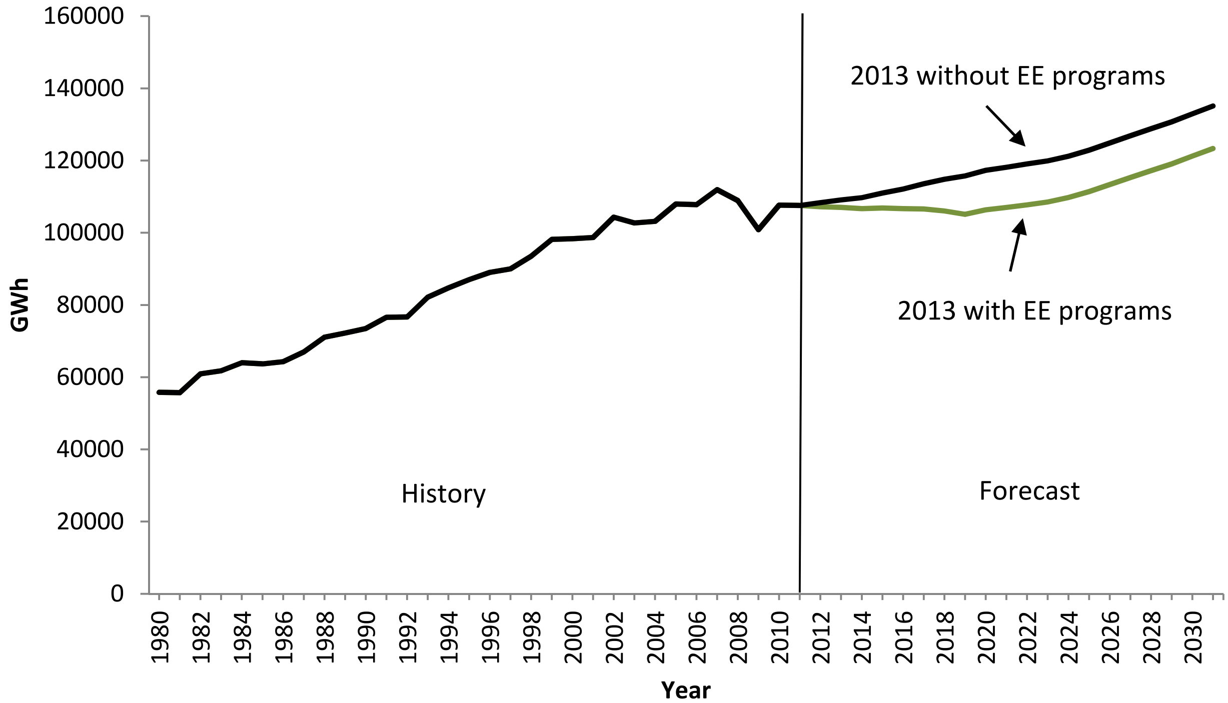
Figure 1-5. Indiana Electricity Requirements by Scenario in GWh



Resource Implications of Energy Efficiency (EE) Programs

The current electricity and peak demand projections incorporate energy and peak load reductions from the energy efficiency programs. The implementation of these programs by the electric utilities has a significant impact on reducing the total resources required at the statewide level. Figure 1-6 shows the effects of these programs by comparing the Indiana electricity requirements with and without EE programs. While both projections have a common starting point, the forecast with EE energy reductions is below the forecast without EE programs for the entire forecast period. The figure shows that the gap between these projections steadily widens between 2012 and 2019, which is the last year of the electric savings plan determined by IURC's DSM order, and then it stays constant for the remaining part of the forecast horizon. If the EE programs were assumed to be absent in the system, the annual growth rate of electricity requirements would be about 1.17 percent, which is 0.43 percent higher than the current base scenario projection.

Figure 1-6. Indiana Electricity Requirements in GWh (Base case scenario with and without EE Programs)



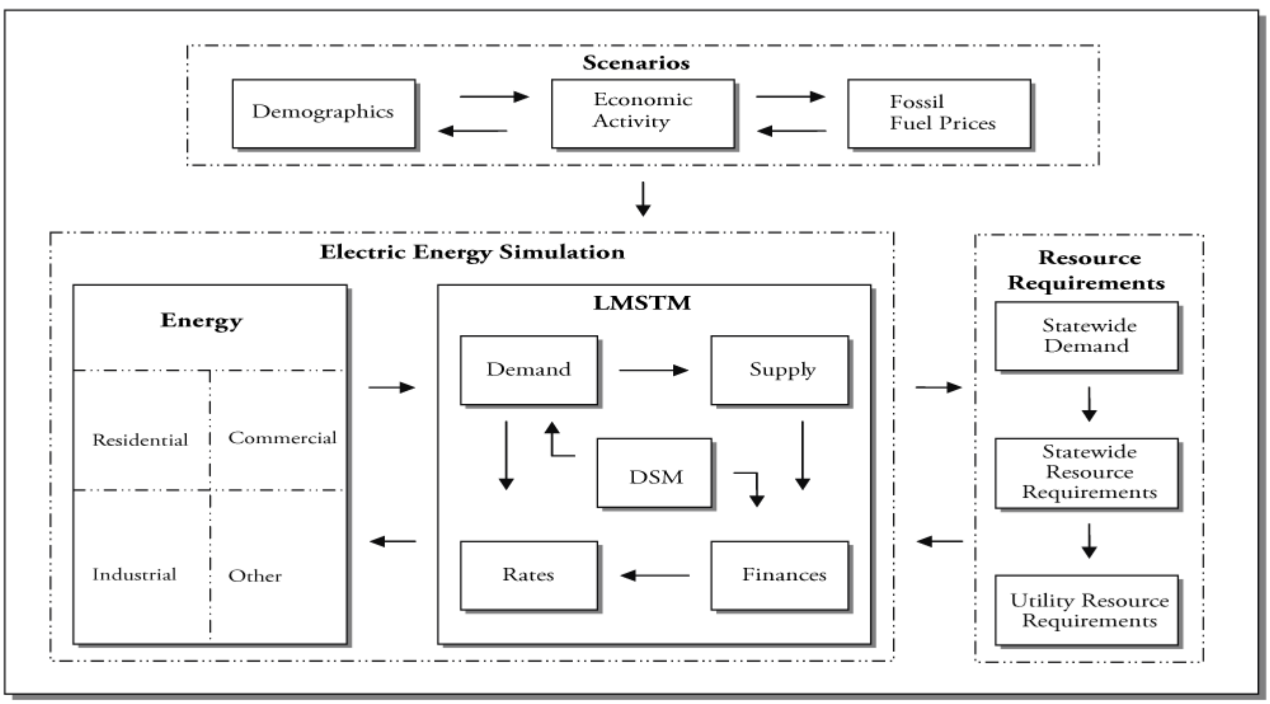
Chapter 2

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. Beginning with the 2011 forecast, SUFG switched to the residential end-use model 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.

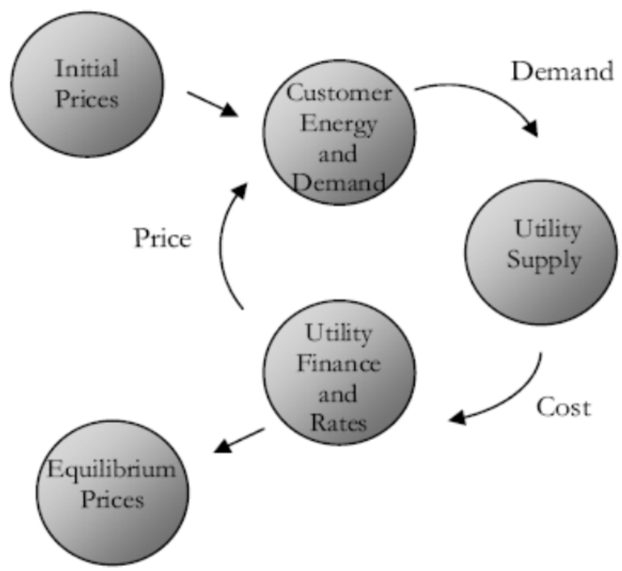
Load Management Strategy Testing Model

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 18.3 percent. This represents a higher reserve margin than the 15.8 percent figure used in the 2011 forecast due to changing RTO requirements. It should be noted that the change from a 15 percent to a 15.8 or 18.3 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 the more rigorous analyses of the RTOs as compared to the previous rule of thumb method.

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 18.3 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).

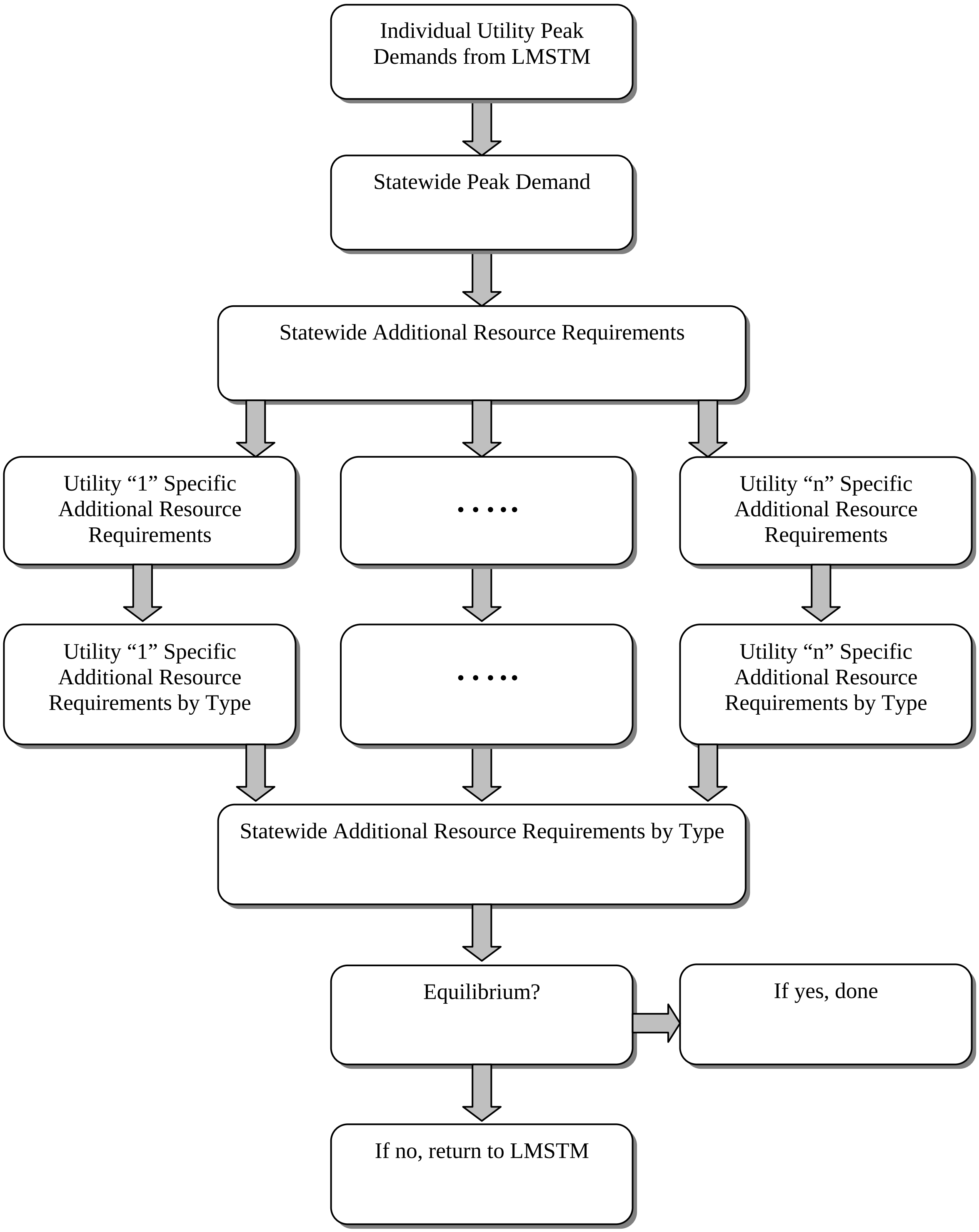
The required resources are then assigned to the individual utilities with the lowest reserve margins, so that all utilities have similar reserve margins. Even if the state's reserve margin meets the 18.3 percent target, resources will be assigned to an individual utility if necessary to bring the utility's reserve margin up to 6 percent. This is done for purposes of model integrity, since the utility dispatch simulation in LMSTM will provide unrealistic results with very low utility reserves. These utility specific additional resource requirements are then assigned to one of three types: base load, intermediate (or cycling), and peaking. 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 0.74 percent for electricity requirements and 0.90 percent for peak demand. As shown in Table 3-3, the growth rate for electricity sales in this forecast is about 0.56 percent lower than the 2011 forecast. The growth within sectors varies significantly with lower growth in the residential and commercial sectors offsetting higher growth in the industrial sector, but the forecast growth for all sectors is markedly below the forecast in 2011. 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 at about the same level as the previous forecast but with a downward trend that situates it below the 2011 projections after 2013. Then, the gap between the projections widens over the forecast horizon. The downward trend in electricity requirements in this forecast is due to more aggressive energy efficiency programs that have been included in the forecast to meet the IURC DSM order. This general pattern is followed in all three sectors.

The growth in peak demand is similarly lower than that projected in 2011 and follows a similar pattern that is observed for the total energy requirements but with a more pronounced drop in the beginning of the forecast. The large drop in the first year of the forecast (2012) is due to the inclusion of a significant amount of demand response. About 1,200 MW of demand response, consisting of direct load control and industrial interruptible loads, is available. The peak demand numbers in the forecast are net of these demand response loads, since additional resources will not be needed in the future to meet these loads during the peak demand time. Forecast peak demand growth is slightly higher than that of electricity requirements (0.90 versus 0.74 percent) because demand response is projected to grow more slowly than other loads that contribute to peak demand. Uncontrolled peak demand, which is the peak demand level prior to load reduction from demand response, is projected to grow at a similar level to electricity requirements. 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 about 170 MW compared to about 260 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 (includes energy efficiency and demand response programs) are netted from the demand projection, and generic resources are added as necessary to maintain an 18.3 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

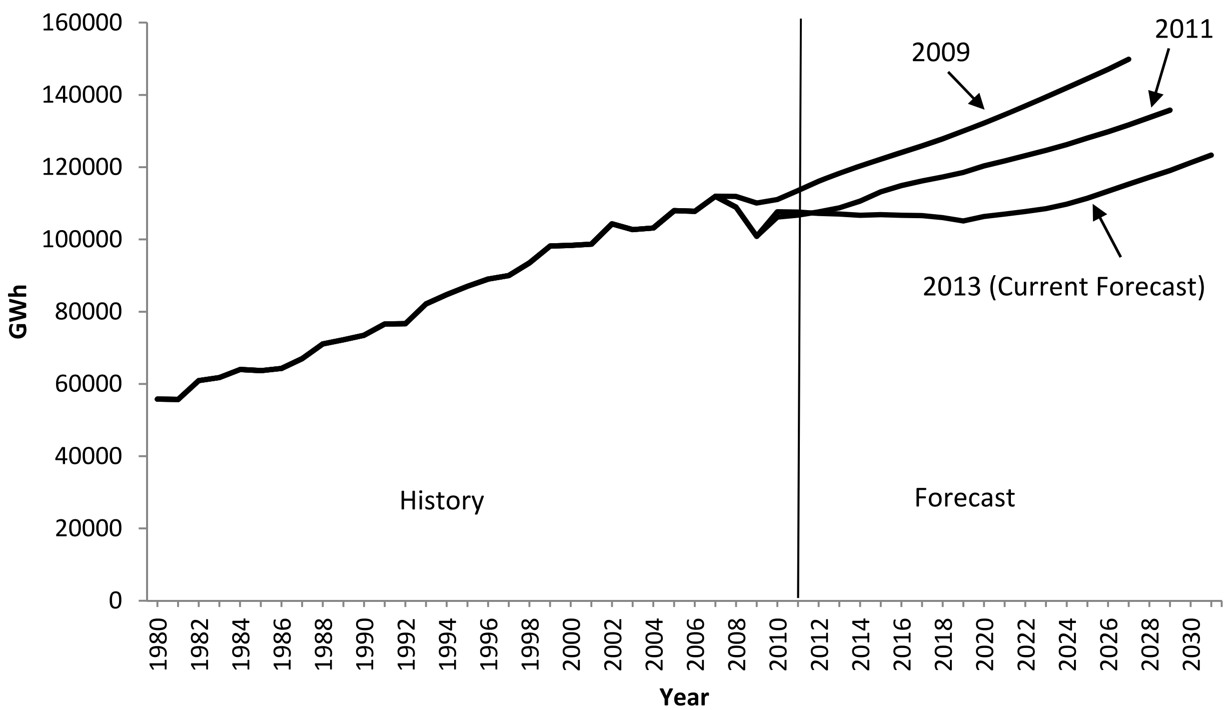
Beginning with this forecast, SUFG has adjusted its demand-side management (DSM) programs definition to more closely align with the commonly accepted meaning for these types of resources. For previous forecasts, SUFG classified industrial interruptible or buy-through contracts as interruptible loads and utility energy efficiency and direct load control programs as DSM. In this forecast, the term DSM includes two components: energy efficiency (EE) and demand response (DR) programs. The EE component accounts for energy reduction and its correspondent peak load reduction from conservation programs (i.e. high efficiency appliances, changes in behavior or operations, etc.) implemented by utilities. DR programs include all the peak load reductions from load management programs (i.e. interruptible, direct load control (DLC), voltage reduction, etc.) that shift energy usage from times of high demand to times of lower demand but do not affect overall energy usage. The current projection includes the energy and demand impacts of existing or planned utility-sponsored EE programs. Incremental EE programs, which include new programs and the expansion of existing programs, are projected to reduce peak demand by approximately 135 MW at the beginning of the forecast period and by over 1,833 MW at the end of the forecast. EE projections reflect the estimated impact of the IURC's DSM order of December 2009.

In addition to EE programs, peak demand projections are reduced due to DR programs. Load reductions from DR programs are projected to increase from 1,205 MW to about 1,420 MW over the forecast horizon. See Chapter 4 for additional information about DSM loads.

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

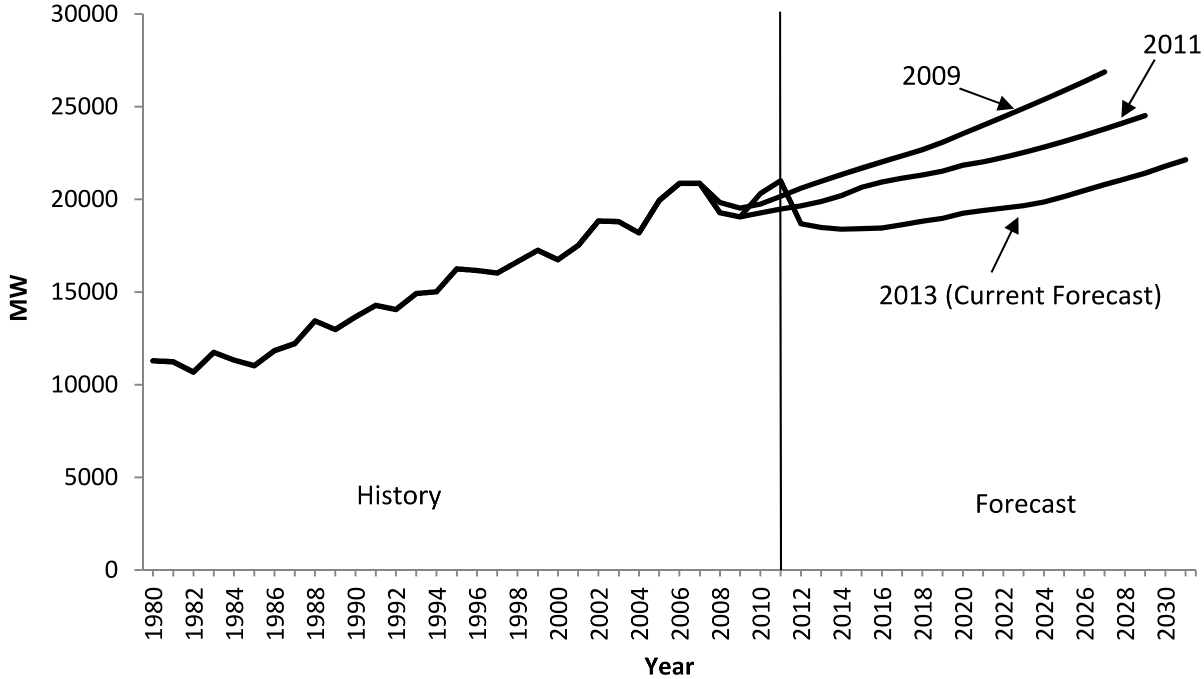
Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2009	1.55	2008-2027
2011	1.30	2010-2029
2013	0.74	2012-2031

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**
2009	1.61	2008-2027
2011	1.28	2010-2029
2013	0.90	2012-2031

Table 3-3. Annual Electricity Sales Growth (Percent) by Sector (Current Forecast vs. 2011 Projections)

Sector	Current (2012-2031)	2011 (2011-2029)
Residential	0.37	0.71
Commercial	0.33	0.89
Industrial	1.29	2.11
Total	0.74	1.30

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. As of the time this forecast was produced, no decision had been made as to whether Duke Energy would retire Wabash River unit 6 or repower it to use natural gas. SUFG has modeled it as being retired in 2015 in this forecast. If the unit is repowered, there would be a corresponding increase in the amount of existing resources by about 318 MW and an equal decrease in the amount of required resources.

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 an 18.3 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 higher than the 15.8 percent figure used in 2011. 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. Prior to the 2011 forecast, pulverized coal (PC) units were used as the basis for baseload purchases. This change was made because the 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 very little need for resources in the near term, with 10 MW of peaking, 30 MW of cycling and no baseload resources required by 2014. These requirements are lower than those identified in the 2011 forecast primarily because of a lower peak demand projections due to increased energy efficiency and demand response. By 2020, a total of 1,280 MW of resource additions are required, of which 320 MW is peaking, 310 MW is cycling, and 650 MW is baseload. About 2,370 MW of resource additions are required by 2025, and approximately 5,080 MW by 2031. The net change in generation includes the retirement of units as reported in the utilities' 2011 IRP filings, changes in firm purchases and sales, and the addition of approved new capacity. The required resources indicated through 2015 are needed for purposes of modeling integrity to prevent individual utility reserves from being too low, rather than because the state falls below the 18.3 percent threshold. The methodology for determining and assigning required resources at statewide and individual utility levels is described in Chapter 2.

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 was 2011. Therefore, 2012 and 2013 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.

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

	Uncontrolled Peak Demand[1]	Demand Response[2]	Net Peak Demand[3]	Existing/ Approved Capacity[4]	Incremental Change in Capacity[5]	Projected Additional Resource Requirements[6]				Total Resources[7]	Reserve Margin[8] (percent)
						Peaking	Cycling	Baseload	Total		
2011				23,326							
2012	19,888	1,205	18,683	23,406	80	20	80	20	120	23,526	26
2013	19,777	1,296	18,481	23,899	493	10	30	-	40	23,939	30
2014	19,718	1,329	18,389	23,781	-119	10	30	-	40	23,821	30
2015	19,769	1,357	18,412	22,034	-1747	20	50	-	70	22,104	20
2016	19,823	1,371	18,452	21,512	-523	130	160	120	410	21,922	19
2017	20,011	1,381	18,631	21,512	0	200	220	210	630	22,142	19
2018	20,208	1,390	18,818	21,568	56	190	240	460	890	22,458	19
2019	20,375	1,400	18,975	21,615	47	230	260	570	1,060	22,675	19
2020	20,663	1,407	19,256	21,590	-25	320	310	650	1,280	22,870	19
2021	20,814	1,414	19,401	21,569	-21	370	340	740	1,450	23,019	19
2022	20,944	1,416	19,528	21,619	50	390	360	790	1,540	23,159	19
2023	21,076	1,418	19,658	21,476	-143	480	420	920	1,820	23,296	19
2024	21,281	1,419	19,861	21,469	-7	510	480	1,060	2,050	23,519	18
2025	21,567	1,420	20,147	21,469	0	590	590	1,190	2,370	23,839	18
2026	21,896	1,420	20,476	21,428	-41	690	680	1,420	2,790	24,218	18
2027	22,222	1,420	20,801	21,400	-28	930	750	1,530	3,210	24,610	18
2028	22,520	1,421	21,099	21,381	-19	1,040	860	1,670	3,570	24,951	18
2029	22,833	1,421	21,413	21,108	-273	1,160	970	2,090	4,220	25,328	18
2030	23,210	1,421	21,790	21,093	-16	1,280	1,100	2,300	4,680	25,773	18
2031	23,558	1,421	22,138	21,085	-7	1,360	1,200	2,520	5,080	26,165	18

1 Uncontrolled peak demand is the peak demand prior to any load reduction from demand response programs being called upon.

2 Demand response is all the measures designed to shift load away from peak demand periods. These include interruptible and direct load control programs affecting peak demand.

3 Net peak demand is the peak demand after load reductions from demand response programs are taken into account.

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

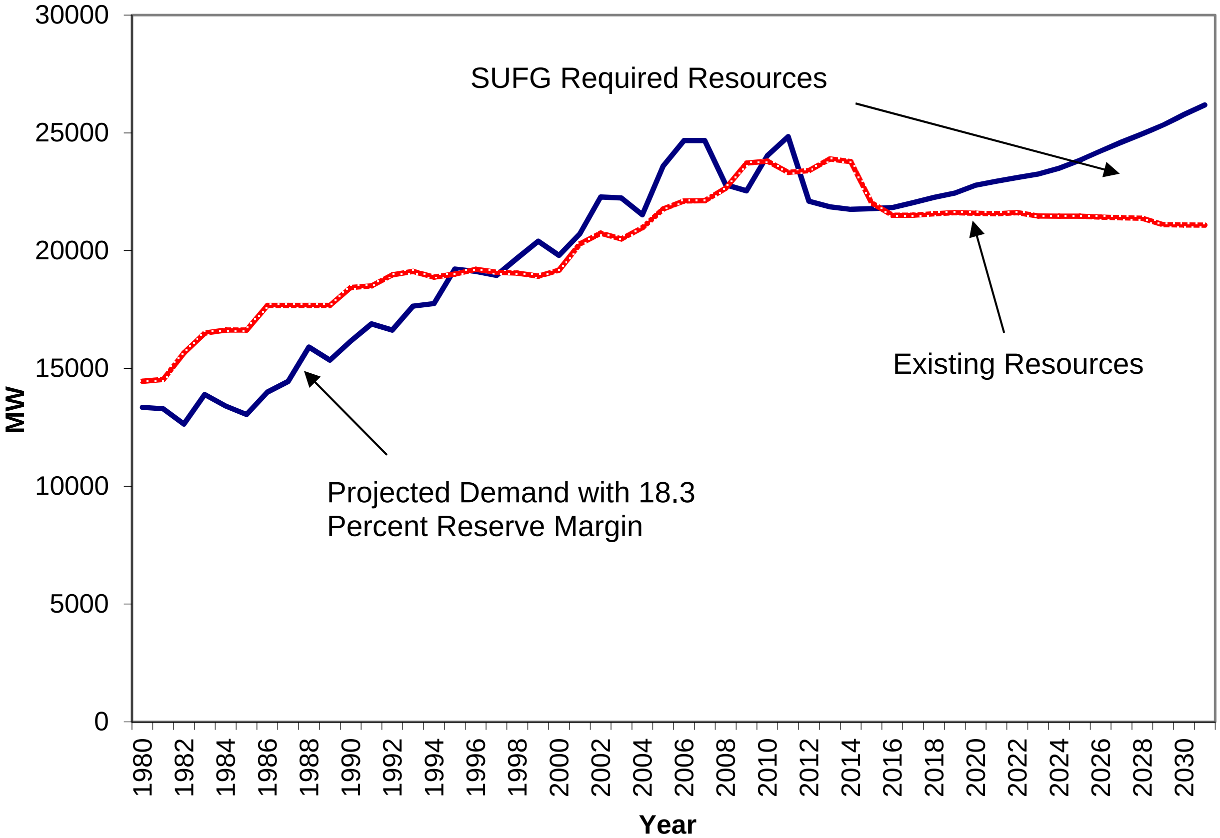
5 Incremental change in capacity is the change in existing/approved capacity from the previous year. The change is due to new, approved capacity becoming operational, retirements of existing capacity, and changes in firm purchases and sales.

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

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

8 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 30 percent from 2012 to 2023 and then slowly decrease until 2026 before maintaining 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. Figure 3-4 also shows the price trajectory for the supplemental analysis of potential EPA regulations that SUFG released in January 2012 (labeled "2011 w/ EPA"). The price projection labeled "2009" is the base case projection contained in SUFG's 2009 forecast and the one labeled "2011" is the base case projections from SUFG's 2011 report. For the prior price forecasts, SUFG rescaled the original price projections to 2011 dollars (from 2007 dollars for the 2009 projection, and from 2009 dollars for the 2011 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, costs associated with resources required to meet future load; 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 Mercury and Air Toxics Standards (MATS) are included. The Cross-State Air Pollution Rule (CSAPR) was vacated by the D.C. Circuit Court and will be considered by the U.S. Supreme Court. Since CSAPR is currently vacated, it is not modeled but compliance with MATS largely implies compliance with CSAPR, so this has little effect. The generators that SUFG uses to approximate the costs of new resources are chosen to comply with the greenhouse gas rules for new plants. Other non-finalized rules, such as those affecting greenhouse gas emissions for existing generators, cooling water, and coal ash disposal are not included.

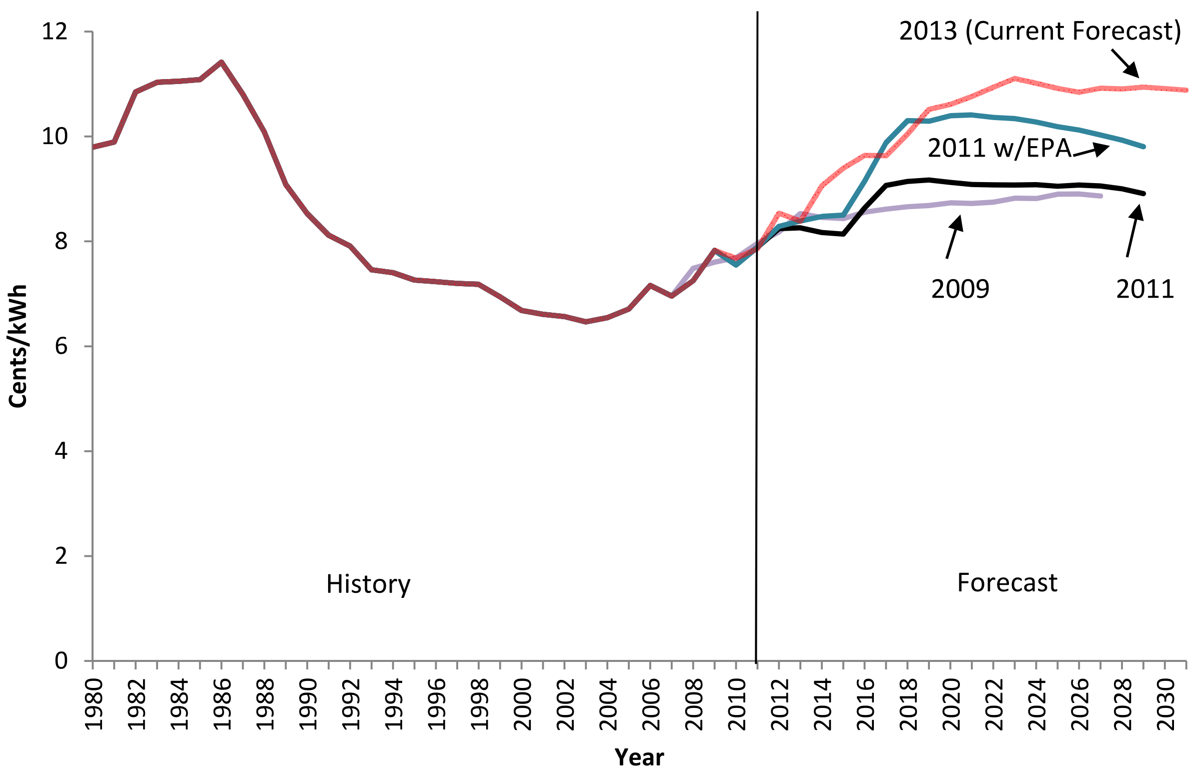
Low and High Scenarios

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 energy requirements for the low and high scenarios are 0.45 percent lower and 0.43 percent higher than the base scenario. 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**
2009	0.89	2008-2027
2011	0.88	2010-2029
2013	1.29	2012-2031

Figure 3-4. Indiana Real Price Projections in cents/kWh (2011 Dollars) (Historical, Current and Previous Forecasts)



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

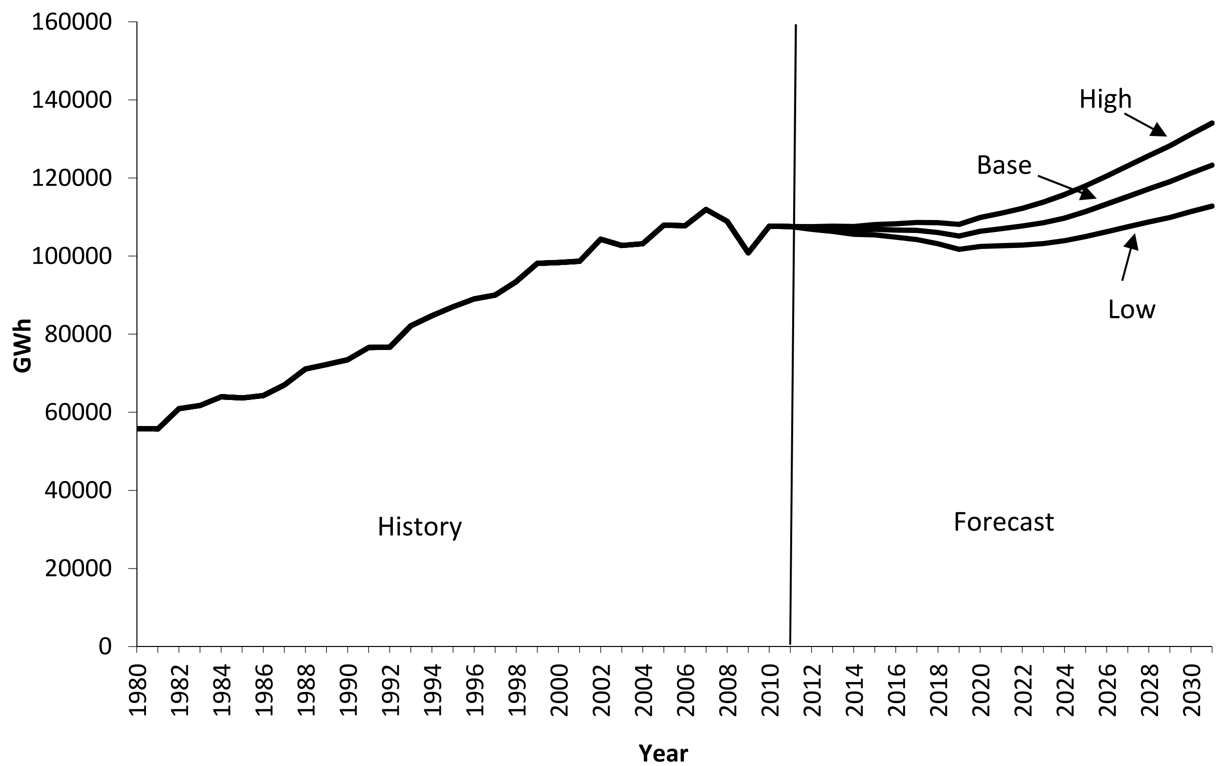
Resource and Price Implications of Low and High Scenarios

Resource plans are developed for the low and high scenarios using the same methodology as the base plan. Demand-side resources, including energy efficiency and demand response 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 7,100 MW over the horizon are required in the high scenario compared to 3,220 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 4.0 percent of those projected in the base case. This is because the higher costs associated with meeting the increased load for the high case are spread over a greater amount of energy. For the low case, the lower costs are offset by the lower amount of energy.

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

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2012-2031	0.74	0.29	1.17

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

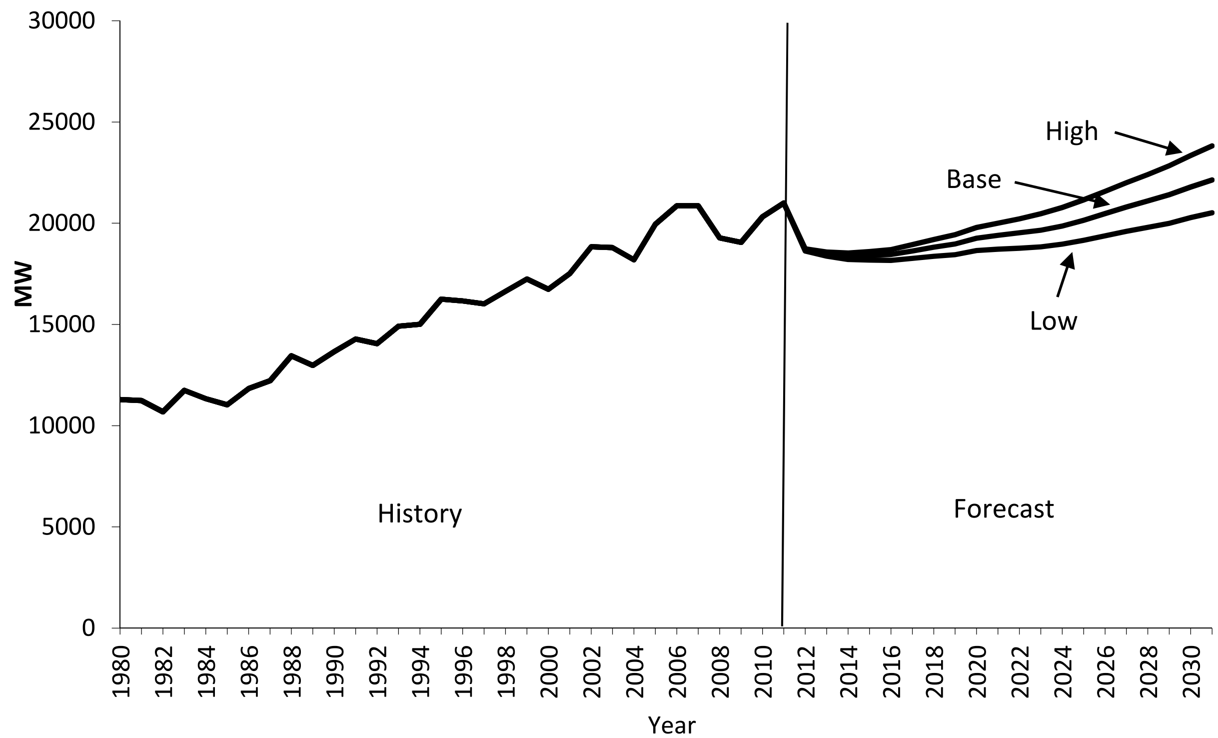


Note: See the Appendix to this report for historical and projected values.

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

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2012-2031	0.90	0.51	1.27

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
2012	20	80	20	120	20	80	20	120	20	80	20	120
2013	10	30	0	40	10	30	0	40	0	20	0	20
2014	10	30	0	40	10	40	0	50	10	20	0	30
2015	20	50	0	70	40	70	10	120	10	30	0	40
2016	130	160	120	410	230	240	220	690	40	60	10	110
2017	200	220	210	630	310	300	360	970	80	120	50	250
2018	190	240	460	890	320	330	590	1,240	80	130	320	530
2019	230	260	570	1,060	380	380	710	1,470	80	150	380	610
2020	320	310	650	1,280	520	470	850	1,840	150	170	450	770
2021	370	340	740	1,450	570	550	1,000	2,120	160	200	520	880
2022	390	360	790	1,540	610	600	1,080	2,290	170	190	540	900
2023	480	420	920	1,820	740	690	1,290	2,720	250	220	610	1,080
2024	510	480	1,060	2,050	820	790	1,510	3,120	260	240	710	1,210
2025	590	590	1,190	2,370	950	900	1,690	3,540	310	290	800	1,400
2026	690	680	1,420	2,790	1,070	1,040	1,960	4,070	360	340	950	1,650
2027	930	750	1,530	3,210	1,360	1,120	2,110	4,590	550	400	1,060	2,010
2028	1,040	860	1,670	3,570	1,470	1,260	2,370	5,100	610	450	1,120	2,180
2029	1,160	970	2,090	4,220	1,590	1,390	2,910	5,890	690	540	1,400	2,630
2030	1,280	1,100	2,300	4,680	1,700	1,540	3,260	6,500	750	660	1,520	2,930
2031	1,360	1,200	2,520	5,080	1,820	1,680	3,580	7,080	830	760	1,630	3,220

Resource Implications of Energy Efficiency (EE) Programs

The current electricity and peak demand projections incorporate energy and peak load reductions from the energy efficiency programs. The implementation of these programs by the electric utilities has a significant impact on reducing the total resources required at the statewide level. Figure 3-7 shows the effects of these programs by comparing the Indiana electricity requirements with and without EE programs. While both projections have a common starting point, the forecast with EE energy reductions is below the forecast without EE programs for the entire forecast period. The figure shows that the gap between these projections steadily widens between 2012 and 2019, which is the last year of the electric savings plan determined by IURC's DSM order, and then it stays constant for the remaining part of the forecast horizon. If the EE programs were assumed to be absent from the system, the annual growth rate of electricity requirements would be about 1.17 percent, which is 0.43 percent higher than the current base scenario projection.

As shown in Figure 3-8, the growth in peak demand requirements without EE programs is also higher than the base case scenario with EE Programs and follows the same pattern that is observed for the total energy requirements. The growth rate for peak demand without EE programs is about 0.38 percent higher than the peak demand with EE reductions. In Figure 3-8 the average annual peak load increase is 258 MW compared to about 173 MW in the base case scenario, which represents an annual average impact of 85 MW because the implementation of these conservation programs.

Figure 3-7. Indiana Electricity Requirements in GWh (Base case scenario with and without EE Programs)

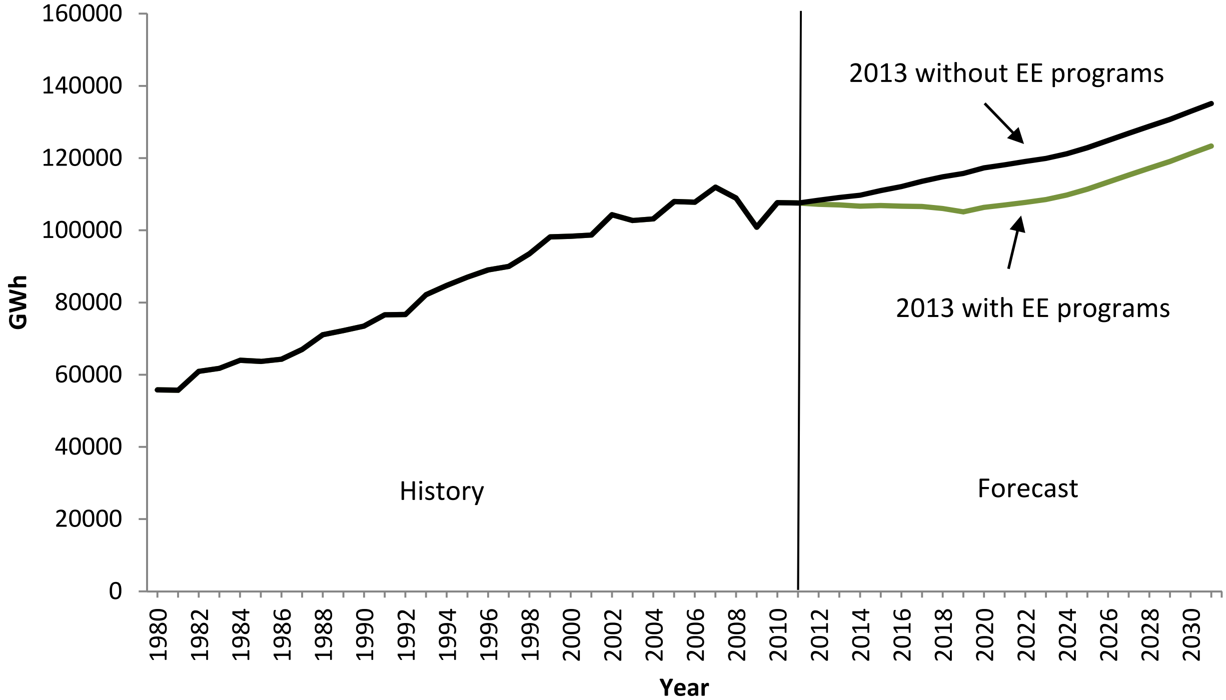
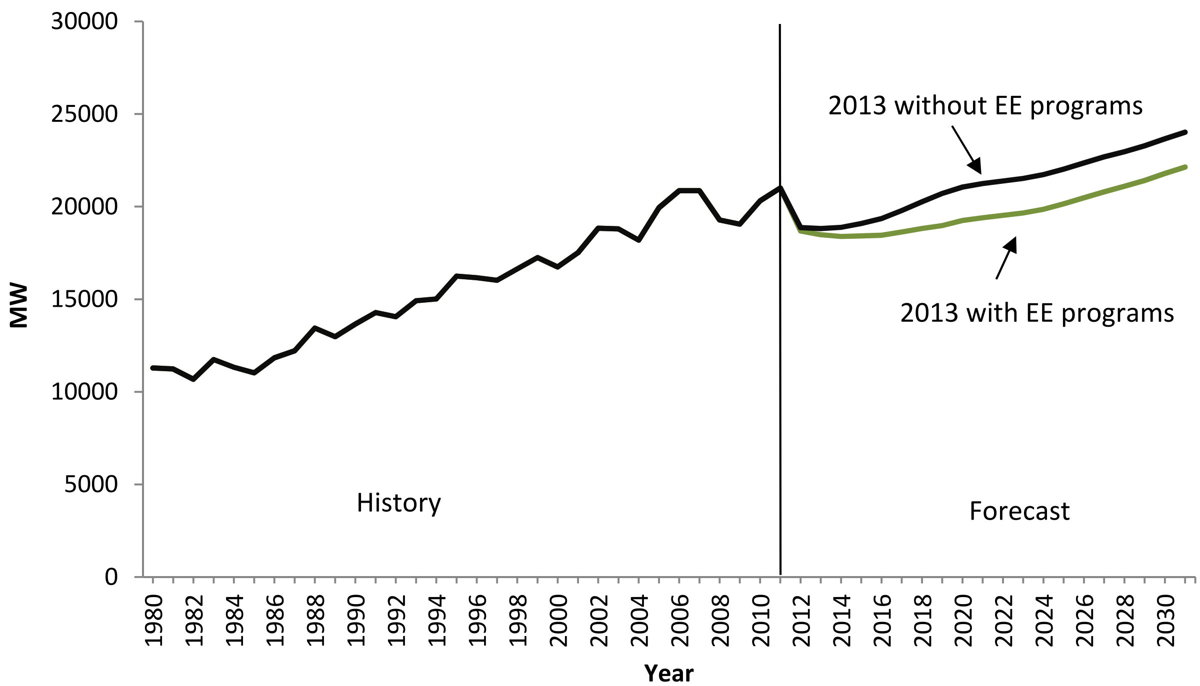


Figure 3-8. Indiana Peak Demand Requirements in MW (Base case scenario with and without EE Programs)



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 2013 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 2012-2033" [CEMR] are:

Federal tax rates are assumed to increase over the projection period. Specifically, the average tax rate on personal income increases over 12 percent, while the payroll tax rate increases by almost 5 percent. Federal grants to state and local governments are assumed to grow at about 3.8 percent annually early in the projection period and then rise to about a 4.2 percent by the end of the projection period. The federal government deficit declines significantly from 6.9 percent of Gross Domestic Product (GDP) in 2012 to 2.6 percent by the end of the projection period.

State and local tax rates are roughly stable over the projection period. This allows these governments to run moderate surpluses during the second half of 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 1.4 percent.

As a result of these assumptions, real GDP for the U.S. economy is projected to grow at an average annual rate of 2.83 percent and U.S. employment growth averages 0.90 percent over the 2012 to 2031 period.

In Indiana, total employment is projected to grow at an average annual rate of 0.88 percent from 2012 through 2031. The key Indiana economic projections are:

Real personal income (a residential sector model driver) is expected to grow at a 2.15 percent annual rate.

Non-manufacturing employment (the commercial sector model driver) is expected to average a 0.97 percent annual growth rate over the forecast horizon.

Despite the low growth in manufacturing employment, manufacturing Gross State Product (GSP) (the industrial sector model driver) is expected to rise at a 3.58 percent annual rate as gains in productivity far outpace meager growth in employment.

CEMR's macroeconomic projections reflect a continuing very slow recovery from the recession of 2008-2009 and in general are more pessimistic than the projections used in the 2011 Forecast.

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 0.34 percent per year (to 2.48), non-manufacturing employment growth increases 0.10 percent (to 1.08) while Indiana real manufacturing GSP growth is increased by 0.73 percent (to 4.31). 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 1.82, 0.87 and 2.89 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 0.51 percent per year, for the period 2010-2030. This projection is based on the 2010 Census and includes projections of county population by age group. The fastest growing age groups are those of seniors age 65+ (2.86 percent) and young adults 25-44 (0.23 percent). Older adults aged 45-64 are projected to decline 0.35 percent. This marks a change from the previous forecast developed based on the 2000 Census that had that age group as the second fastest growing in the state. Population growth in total 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 65 (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 0.1 percent from 2005-2011. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of about 1.17 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 2009	Feb 2011	Feb 2013
	1985-1990	1990-1995	1995-2000	2000-2005	2005-2011	2008-2027	2010-2029	2012-2031
United States								
Real Personal Income	2.95	2.04	4.08	1.73	1.37	2.76	2.80	2.73
Total Employment	2.36	1.38	2.37	0.25	-0.29	1.00	1.25	0.90
Real Gross Domestic Product	3.25	2.38	4.36	2.39	0.87	2.76	3.05	2.83
Personal Consumer Expenditure Deflator	3.79	2.77	1.87	2.20	2.18	1.72	1.51	1.60
Indiana								
Real Personal Income	2.50	2.48	3.37	1.17	0.74	1.63	2.02	2.15
Employment								
Total Establishment	2.84	1.91	1.22	-0.28	-0.72	0.83	1.21	0.88
Manufacturing	0.91	1.40	0.07	-2.95	-3.39	-1.29	0.30	0.18
Non-Manufacturing	3.82	2.20	1.97	0.47	0.07	1.16	1.31	0.97
Real Gross State Product								
Total	6.17	5.83	4.78	1.98	0.11	2.62	3.02	2.75
Manufacturing	4.76	7.95	4.68	3.26	0.22	2.23	3.44	3.58
Non-Manufacturing	6.81	4.86	4.84	1.43	0.07	2.78	2.86	2.40

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

Fossil Fuel Price Projections

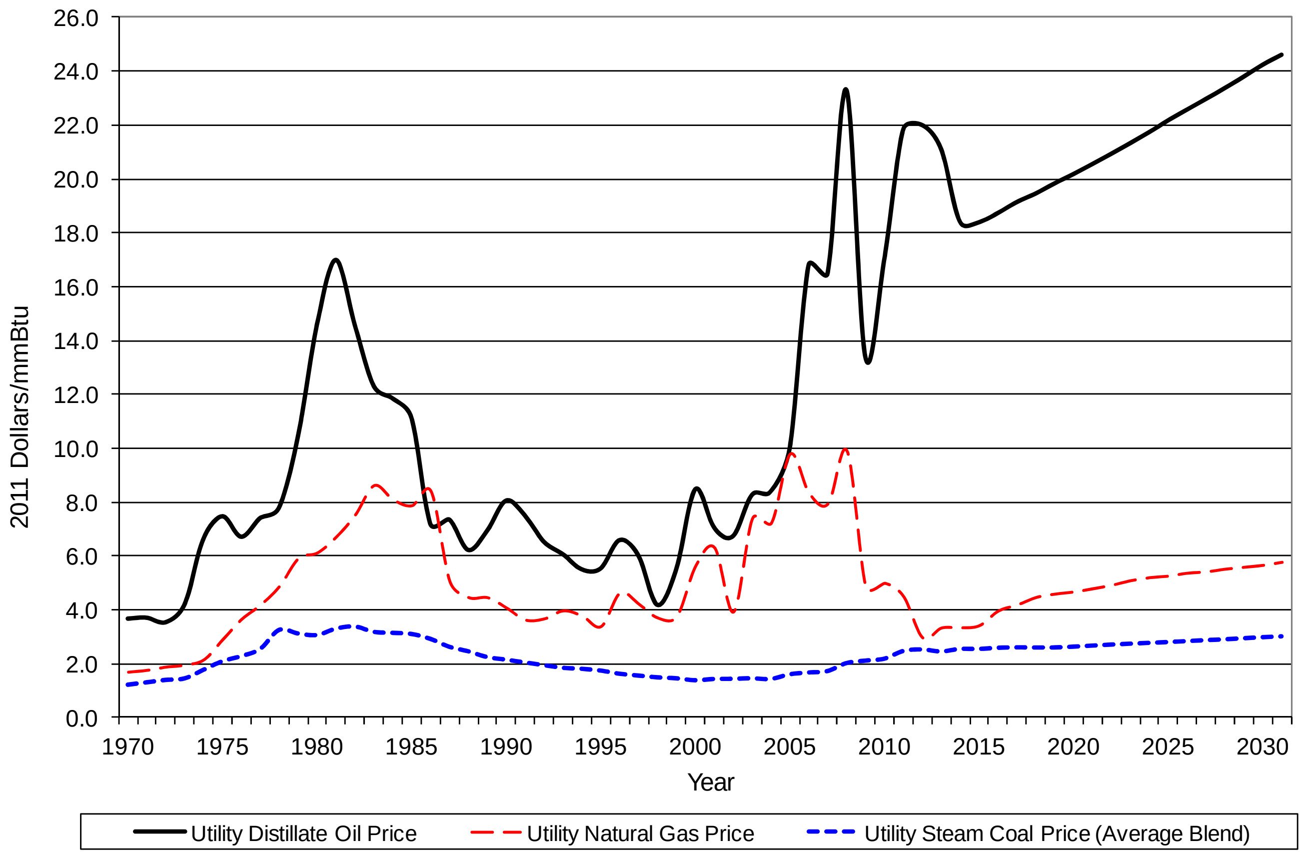
The prices of fossil fuels such as coal, natural gas and oil affect electricity demand in separate and opposing ways. To the extent that any of these fuels are used to generate electricity, they are a determinant of average electricity prices. Electricity generation in Indiana is currently fueled almost 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 2013 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 (2011 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 prices decreased significantly in 2009 coming off of the high prices of 2008. Prices then rebounded somewhat in 2010 before declining again through 2012. They are projected to remain relatively constant through 2015, with a general increase following for the remainder of the forecast horizon.
- Distillate prices also decreased significantly in 2009 coming off of the high prices of 2008. Prices then rebounded significantly through 2011 before declining again in 2012. They are projected to continue declining through 2015 before steadily increasing over the remainder of the forecast horizon.

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

Figure 4-1. Utility Real Fossil Fuel Prices



Demand-Side Management, Energy Efficiency and Demand Response

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. SUFG considers energy efficiency, which affects both energy and peak demand, separately from demand response, which generally affects peak demand but has little impact on energy.

Incremental energy efficiency, 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 2011 are considered to be embedded in the calibration data, so no adjustments are necessary.

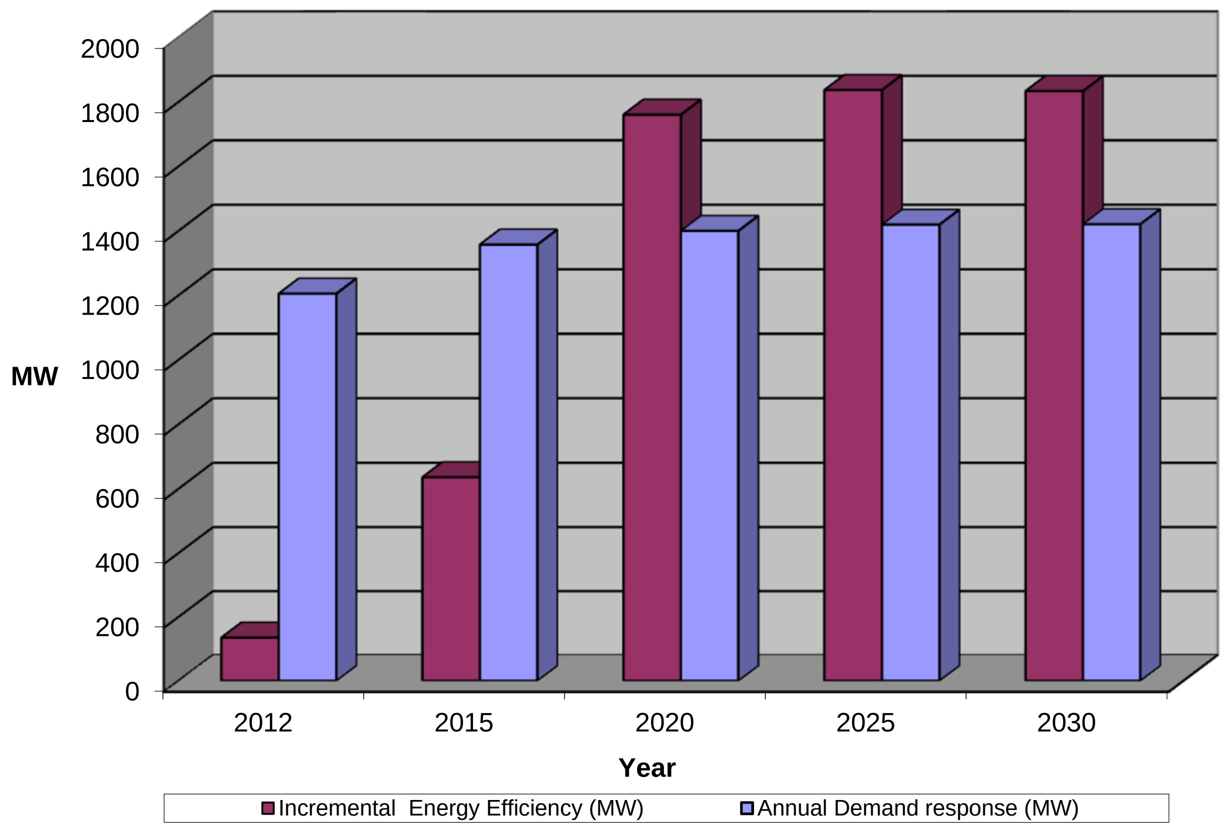
Demand response can include interruptible loads, such as large customers who agree to curtail a fixed amount of their demand during critical periods in exchange for more favorable rates, and direct load control, where the utility has the ability to directly turn off a customer's load for a specified amount of time. Demand response is typically treated differently than energy efficiency. The amount of demand response is 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 2011 and from incremental energy efficiency and annual demand response available in 2012 in Indiana. These estimates are derived from utility integrated resource plan (IRP) filings and from information collected by SUFG directly from the utilities. Energy efficiency projections after 2012 are primarily driven by the IURC's DSM order of December 2009. Since long-term program information was not available for all utilities 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 energy efficiency and demand response for 2012 and at five year intervals starting in the year 2015.

Table 4-2. 2011 Embedded DSM and 2012 Incremental Peak Demand Reductions from Energy Efficiency and Annual Demand Response Programs (MW)

2011 Embedded DSM	2012 Incremental Energy Efficiency	2012 Annual Demand Response
502	135	1,205

Figure 4-2. Projections of Incremental Peak Demand Reductions from Energy Efficiency and Demand Response



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 2011 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 2011 and 2013 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 2011 (herein referred to as CEMR2011) and February 2013 (CEMR2013) long-range projections, the U.S. economy recovered to some extent but the recovery continues to be slow.

Tables 4-3 through 4-5 provide comparisons between the two projections. Selected economic variables are reported annually from 2009 through 2016 and for 2020, 2025, and the last year of the forecast period 2031. 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 CEMR2011 and CEMR2013. Figures 4-3 through 4-5 show long-run projections of real values for the same selected economic variables from 2005 through 2033. Some of the historical values 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 current CEMR projection for non-manufacturing employment is significantly more pessimistic than in 2011. In CEMR2013, the projection of non-manufacturing employment for 2012 is about 45,000 employees (or 1.96 percent) lower than in CEMR2011. In 2013 this gap increases and non-manufacturing employment falls to about 50,000 employees (or 2.13 percent) lower than projected in CEMR2011. From 2014 on, CEMR2013 exhibits even lower growth than previously estimated and employment in this sector continues to be significantly lower than previously expected levels.

Figure 4-3 illustrates the comparison between past and current projections for employment in non-manufacturing. CEMR2013 exhibits lower growth and remains below CEMR2011 for the entire forecast horizon.

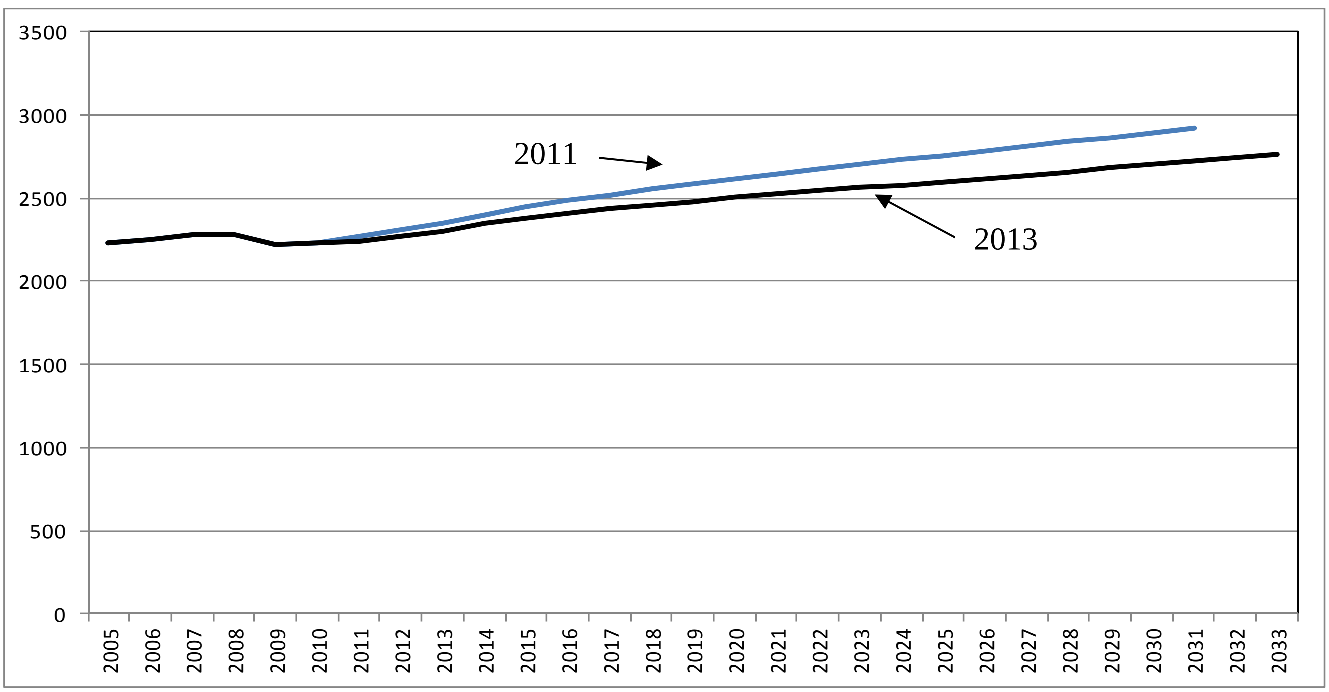
Table 4-3. 2011 and 2013 CEMR Projections for Indiana Non-manufacturing Employment

	Year										
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2020**	**2025**	**2031**
	Thousands of persons										
CEMR2011	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)	2483.9 (1.60)	2618.7 (1.22)	2758.2 (1.03)	2919.2 (0.95)
CEMR2013	2218.1 (-2.86)	2226.6 (0.38)	2239.4 (0.58)	2266.5 (1.21)	2303.1 (1.62)	2348.8 (1.98)	2384.0 (1.50)	2411.2 (1.14)	2503.1 (0.84)	2599.5 (0.73)	2723.5 (0.80)
Percentage change between two projections	-0.10	-0.38	-1.18	-1.96	-2.13	-2.15	-2.49	-2.93	-4.41	-5.75	-6.71

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 impacts of the economy 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. CEMR2013 has a lower projection for real personal income during the first part of the forecast period (2012-2022) followed by a higher projection in the later years (2023-2031) when compared to CEMR2011. CEMR2013 indicates real personal income more than $643 million dollars (-0.31 percent) lower than CEMR2011 in 2012, with the largest negative difference of over $5 billion (-2.40 percent) in 2016. CEMR2013 indicates real personal income more than $429 million dollars (0.16 percent) higher than CEMR2011 in 2023 growing to $7.3 billion dollars (2.37 percent) higher by 2013.

Figure 4-4 illustrates that the CEMR2013 real personal income is projected to grow at a steady rate after 2015 with lower levels 2012-2022 and higher levels 2023-2031 compared to CEMR2011.

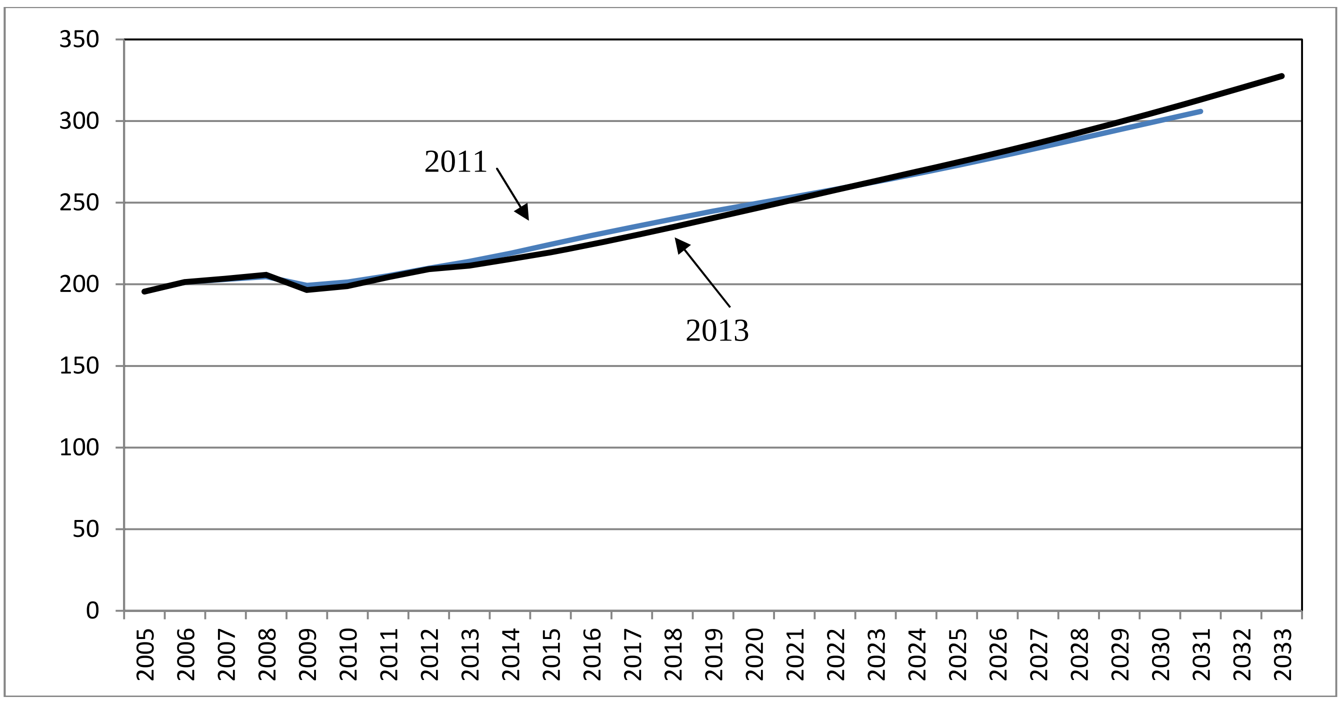
Table 4-4. 2011 and 2013 CEMR Projections for Indiana Real Personal Income

	Year										
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2020**	**2025**	**2031**
	Billions of 2005 $										
CEMR2011	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)	229.80 (2.37)	249.25 (2.12)	272.61 (1.81)	305.91 (1.88)
CEMR2013	196.53 (-4.50)	198.82 (1.17)	204.41 (2.81)	209.23 (2.36)	211.41 (1.04)	215.41 (1.89)	219.53 (1.91)	224.29 (2.17)	246.20 (2.33)	274.61 (2.13)	313.17 (2.27)
Percentage change between two projections	-1.42	-1.27	-0.43	-0.31	-1.22	-1.63	-2.21	-2.40	-1.23	0.73	2.37

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 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. As the figure illustrates, after not increasing in 2008 and 2009, real manufacturing GSP shows growth in 2010. The CEMR2013 projection for the entire forecast period is lower than CEMR2011. The projection for 2012 is over $3 billion (-4.22 percent) less than the CEMR2011 level for that year. The largest difference is in 2016 which is $6.6 billion (-7.79 percent) less than the CEMR2011 level. After 2016, the difference declines until the two projections are similar by 2031.

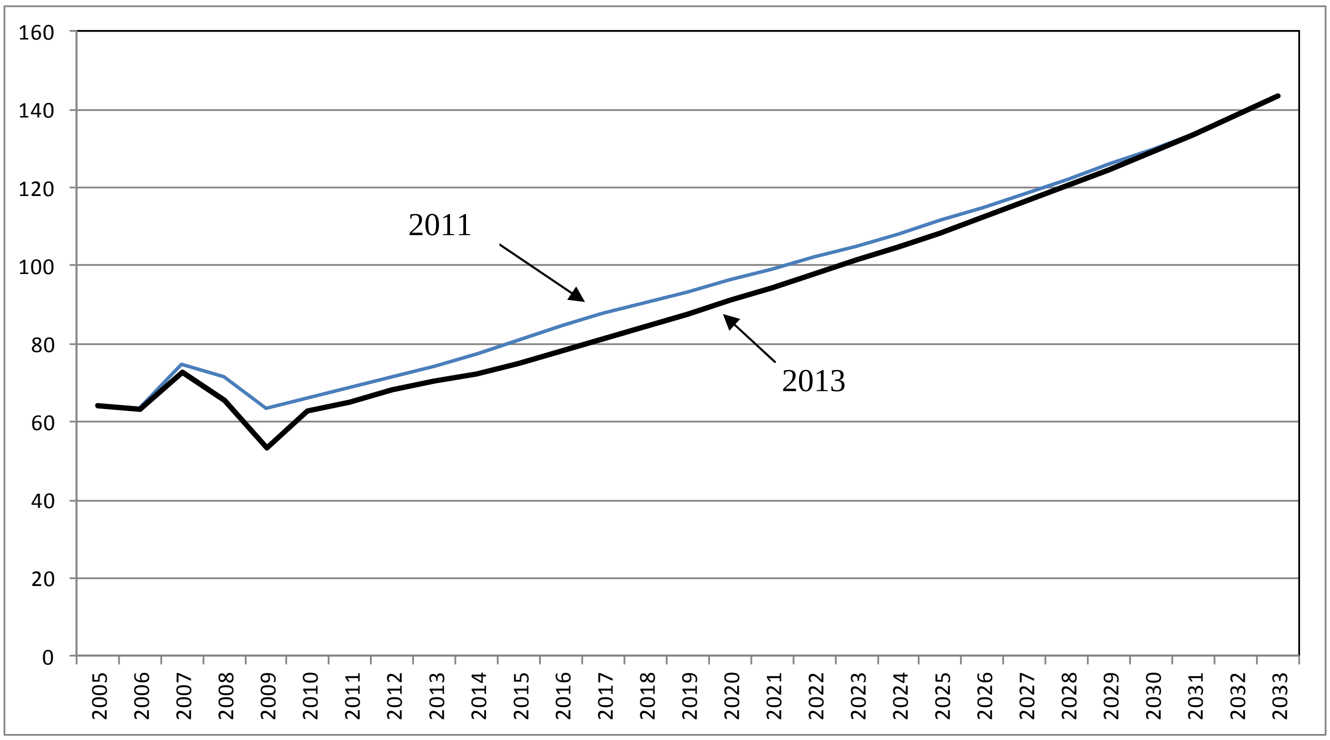
Table 4-5. 2011 and 2013 CEMR Projections for Indiana Real Manufacturing GSP

	Year										
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2020**	**2025**	**2031**
	Billions of 2005 $										
CEMR2011	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)	84.55 (4.18)	96.32 (3.49)	111.47 (2.98)	133.81 (3.08)
CEMR2013	53.25 (-18.64)	62.73 (17.80)	65.15 (3.86)	68.36 (4.94)	70.41 (2.99)	72.22 (2.57)	74.81 (3.59)	77.97 (4.22)	91.03 (3.78)	108.52 (3.47)	133.46 (3.59)
Percentage change between two projections	-16.15	-5.35	-5.16	-4.22	-5.10	-6.71	-7.82	-7.79	-5.49	-2.65	-0.26

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)



Transportation Equipment Industry

The transportation equipment industry, including automobile and auto parts manufacturing, accounts for a considerable portion of the total manufacturing GSP in Indiana. In 2011, this sector represented 20 percent of the total real value of products manufactured in the state.

SUFG felt that CEMR's forecast showed too much growth over the long term for this sector (in both CEMR2011 and CEMR2013), so the forecast was tempered this time. The "CEMR2013 Adjusted" projection calls for growth over the forecast period 2012-2031 of an annual rate of approximately 3.6 percent.

Table 4-6 shows projected growth rates, actual values and percentage rate changes for the transportation equipment industry and includes the comparison between the CEMR2011 and adjusted CEMR2013 projections. The table indicates that the recession had a significant impact on the performance of the automobile sector but it has rebounded strongly.

CEMR2013 shows a large reduction in the production of transportation equipment from 2008 to 2009, with a major decline of over 75 percent in 2009. The sector recovered strongly in 2010 with a 195 percent gain. The industry is projected to keep recovering from the recession for the entire forecast period.

Primary Metals Industry

While the primary metals industry, including production of steel and aluminum, represented slightly more than 9 percent of Indiana manufacturing GSP in 2011, it accounted for 27 percent of the state's industrial electricity sales.

Table 4-7 compares the CEMR projections for 2011 and 2013 for the primary metals industry, which saw an over 17 percent decline between 2008 and 2009 before rebounding strongly in 2010 by about 25 percent and achieving further small gains through 2011. The primary metals industry is projected to remain flat to slightly decreasing from 2012-2016 before showing steadily increasing output for the remainder of the forecast period. Real GSP for this sector is projected to exceed the 2008 levels for the entire the forecast horizon. The CEMR2013 projections for the primary metals industry are higher than the CEMR2011 projections were.

Table 4-6. 2011 and 2013 CEMR Projections for Indiana Real Transportation Equipment GSP

	Year										
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2020**	**2025**	**2031**
	Billions of 2005 $										
CEMR2011	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)	16.38 (5.64)	20.15 (5.12)	25.52 (4.80)	33.81 (4.72)
CEMR2013 Adjusted	2.58 (-74.92)	7.60 (194.69)	8.53 (12.19)	8.95 (4.94)	9.22 (2.99)	9.46 (2.57)	9.8 (3.59)	10.21 (4.22)	11.92 (3.78)	14.21 (3.47)	17.47 (3.59)
Percentage change between two projections	-74.47	-32.93	-28.89	-30.37	-32.05	-34.38	-36.44	-37.66	-40.84	-44.31	-48.32

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

Note: Numbers in parentheses indicate percentage change at annual rate

Table 4-7. 2011 and 2013 CEMR Projections for Indiana Real Primary Metals GSP

	Year										
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2020**	**2025**	**2031**
	Billions of 2005 $										
CEMR2011	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)	5.03 (2.77)	5.41 (1.66)	5.80 (1.35)	6.29 (1.28)
CEMR2013	4.56 (-17.38)	5.67 (24.50)	5.92 (4.46)	6.12 (3.32)	6.11 (-0.24)	5.98 (-2.04)	5.91 (-1.15)	5.88 (-0.60)	6.26 (1.49)	6.65 (1.07)	7.06 (1.06)
Percentage change between two projections	-1.10	29.41	34.44	35.84	32.71	26.53	20.92	16.96	15.69	14.67	12.38

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 2012-2033," Indiana University, February 2013.

Energy Information Administration, "Annual Energy Outlook 2013," April 2013.

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 that SUFG 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 continued to evaluate REDMS and had the vendor update the model to the latest U. S. Department of Energy (DOE) efficiency standards. Starting with the 2011 forecast, SUFG adopted 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.

SUFG chose REDMS as the primary residential sector energy projection model for three reasons. 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.

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 was experienced in the residential sector (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 (almost 2 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 1979-1981, 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 1965-1974, 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 1999-2005, residential household growth decreased slightly to a 1.2 percent annual rate similar to the 1984-1999 period, real electric rates continued to decline, but the growth in personal income, while positive, slowed markedly. Despite the slow growth in income, electricity sales continued to grow at roughly the rate observed during the 1984-1999 period.

More recently, from 2005-2011, the effects of the economic downturn coupled with rising electricity prices resulting in much lower growth in electricity sales. Household growth slowed to one-tenth the rate observed over the preceding twenty years, real electricity prices increased at an average annual rate of 2.3 percent, reversing the trend of the previous twenty years, and real household income declined. The net effect of these changes was to reduce the electricity sales growth rate to 0.2 percent per year, less than one-tenth of that observed over the previous twenty years.

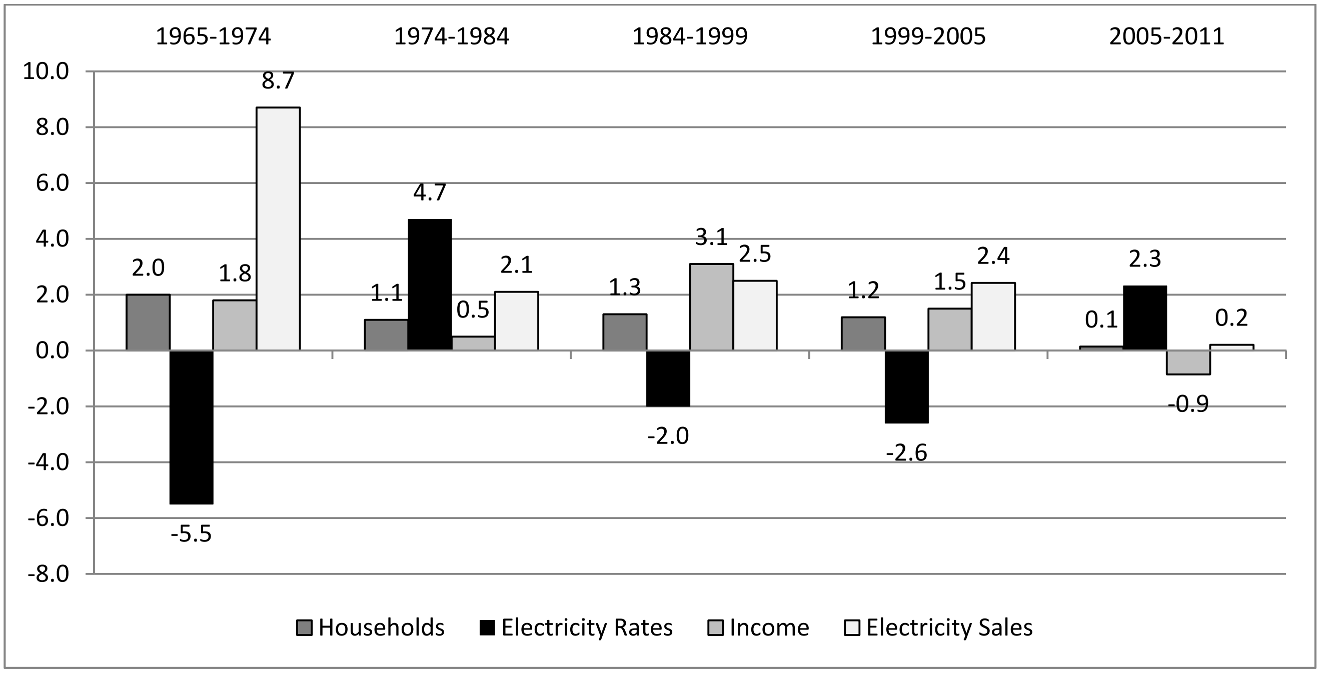
Model Description

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 three dwelling types. It also divides energy use in each dwelling type among ten 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.

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



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;

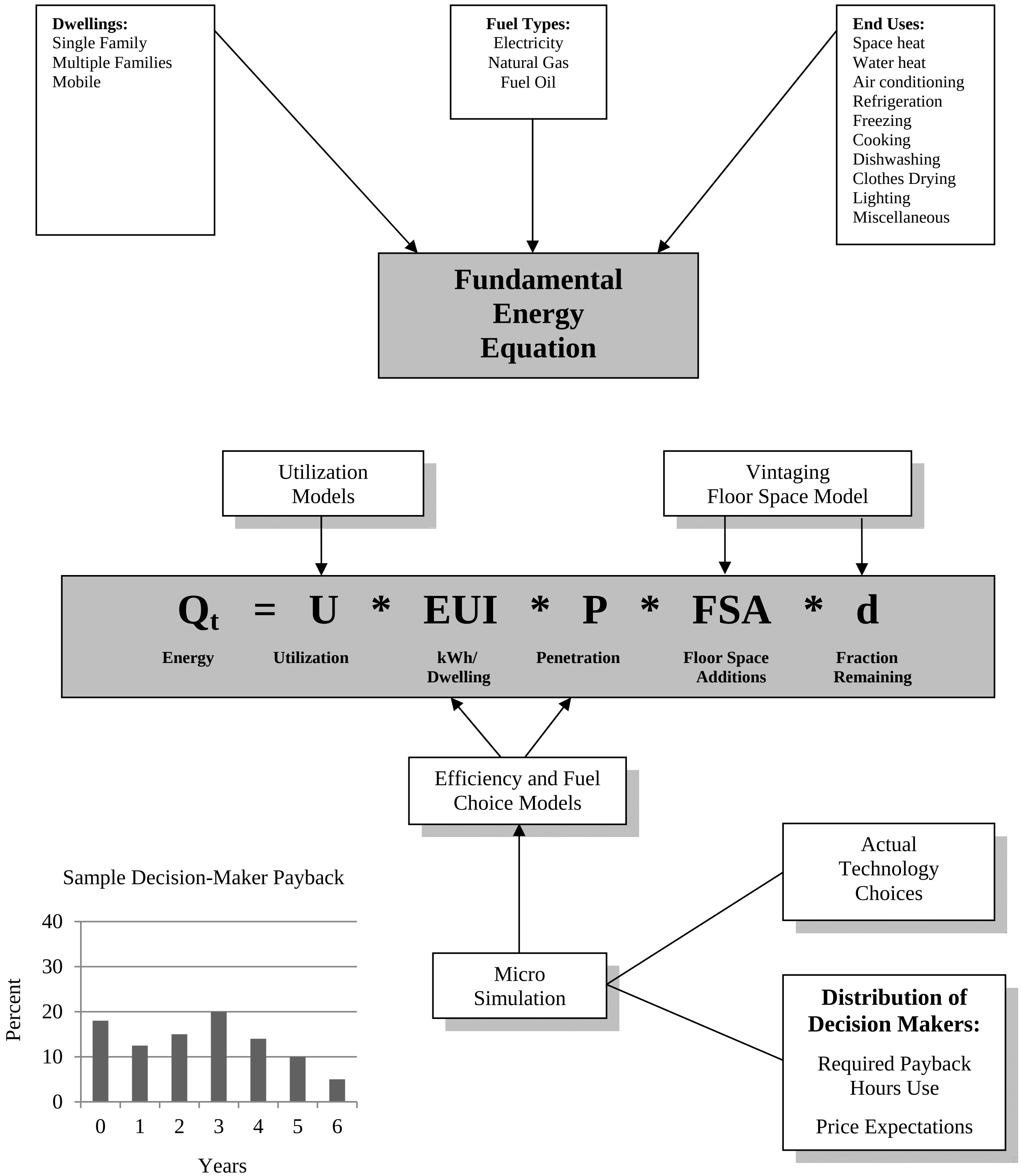
A = dwelling additions by vintage t and dwelling type l; and

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 a statistically significant relationship between fuel prices and fuel specific end-use penetrations was not discernable. 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 considerable 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, a statistically significant relationship between end-use utilization and personal income could not be identified.

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 is historical consumption. The growth rate for the current base projection of Indiana residential electricity sales is 0.37 percent, which is 0.34 percent less than SUFG's 2011 projection of 0.71 percent. The historic and 2013 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 of the previous projections. Table 5-3 summarizes SUFG's base projections of residential electricity sales growth since 2009.

Table 5-4 shows the growth rates of the major residential drivers for the current scenarios and the 2011 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 very similar. While there are some small variations in personal income among the cases, they are not sufficiently large as to result in a difference in growth rates for the base and high scenario within two significant digits.

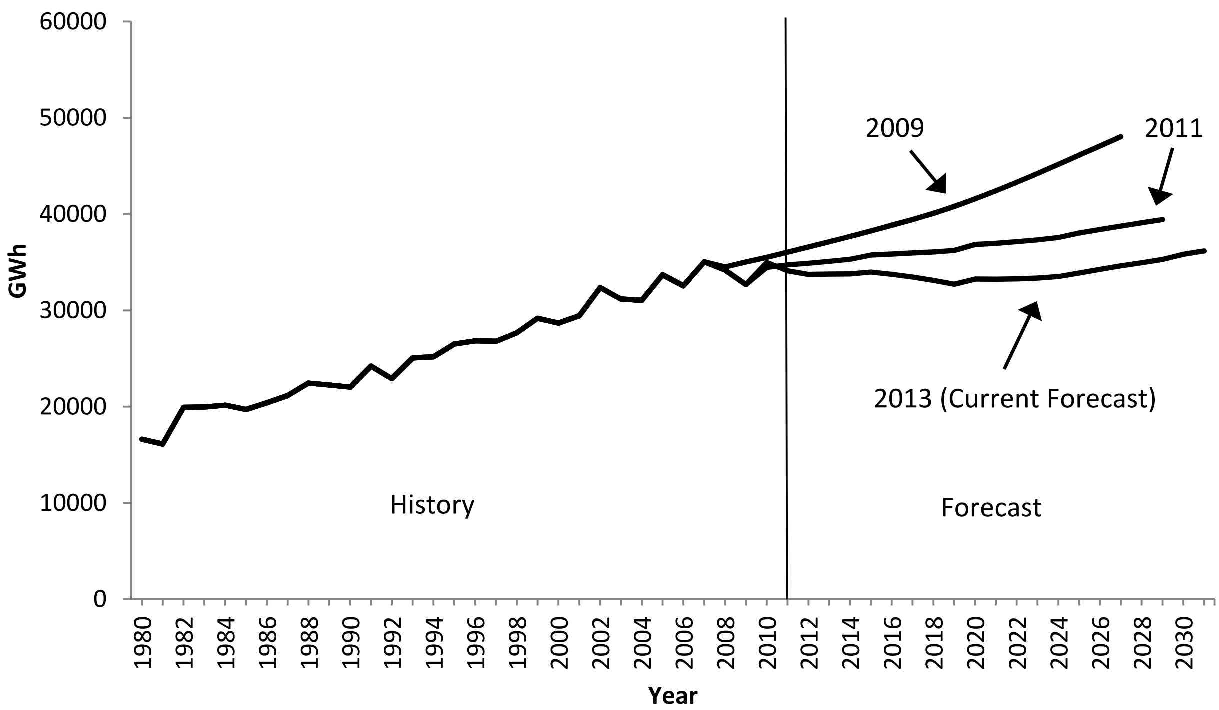
Table 5-3 breaks these projections down by the portion of the growth rate attributable to the growth in number of customers and growth in utilization per customer, with and without DSM. As the table shows, customer growth is partially offset by decreases in utilization, which is the amount of energy used per household. Use per household decreases because of increasing prices and the implementation of new efficiency standards. It can also be seen from the table that residential DSM cuts the sales growth rate by more than half, reducing it from 0.85 percent to 0.37 percent.

As shown in Table 5-5 and Figure 5-4, the growth rates for the high and low residential scenarios are about 0.07 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**
2009	1.75	2008-2027
2011	0.71	2010-2029
2013	0.37	2012-2031

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	Without DSM		With DSM	
	Customers	Utilization	Sales Growth	Utilization	Sales Growth
2013 SUFG Base (2012-2031)	1.17	-0.32	0.85	-0.80	0.37
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

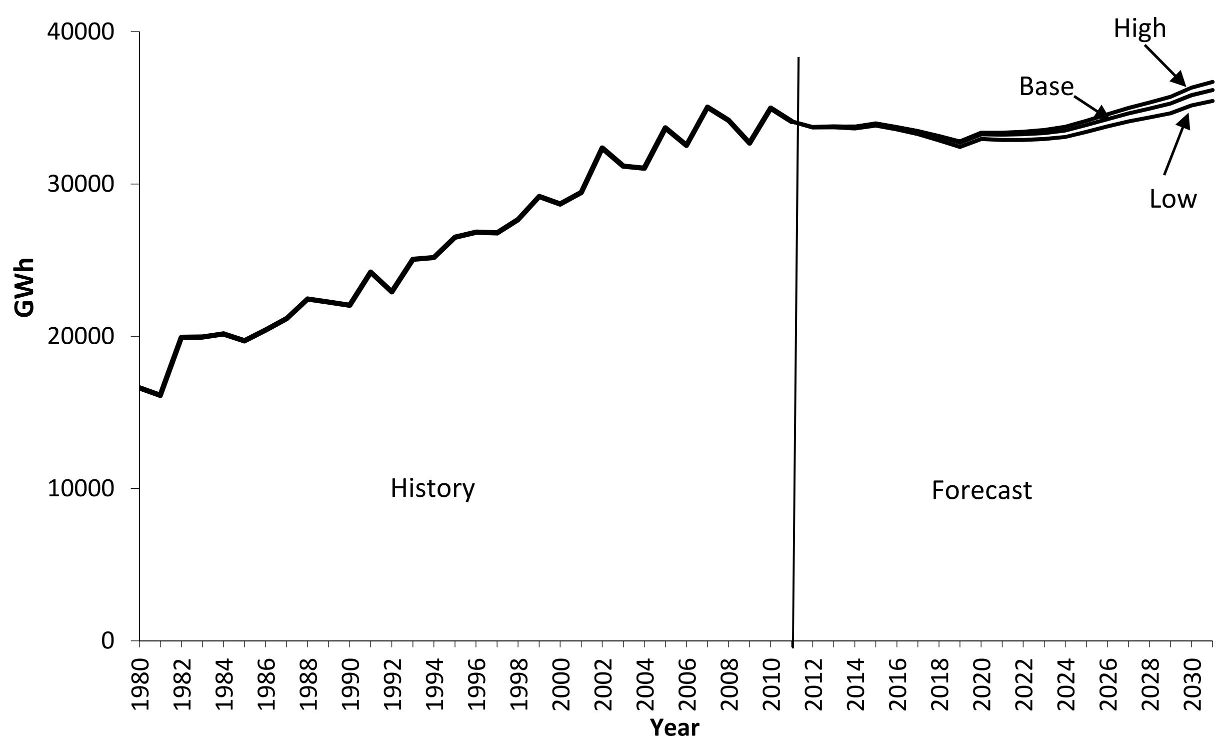
Table 5-4. Residential Model Explanatory Variables - Growth Rates by Forecast (Percent)

Forecast	Current Scenario (2012-2031)			2011 Forecast (2010-2029)
	Base	Low	High	Base
No. of Customers	1.17	1.15	1.17	1.00
Electric Rates	1.34	1.57	1.14	1.08

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

Average Compound Growth Rates			
Forecast Period	Base	Low	High
2012-2031	0.37	0.27	0.44

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 2023, due to the need for additional emissions control equipment, and then to 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. Historical and forecast prices are included in the Appendix of this report.

Figure 5-5. Indiana Residential Base Real Price Projections (in 2011 Dollars)

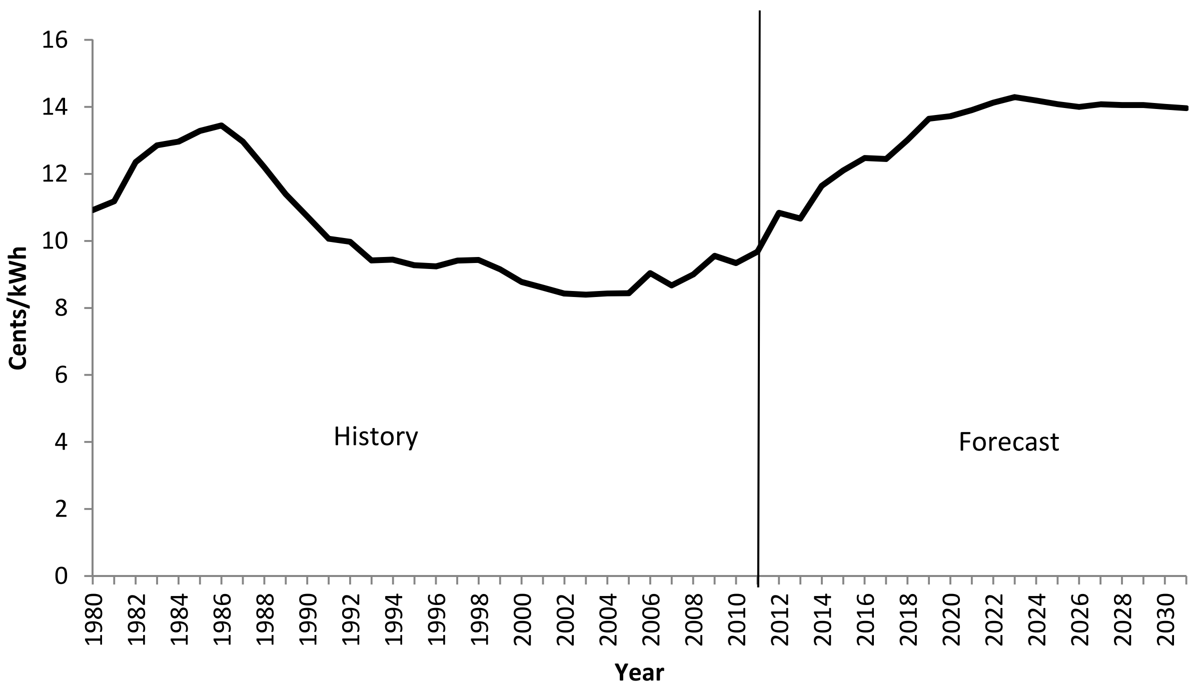


Table 5-6. Indiana Residential Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	**%**
1980-1985	4.00
1985-1990	-4.17
1990-1995	-2.88
1995-2000	-1.09
2000-2005	-0.79
2005-2011	2.32
2012-2031	1.34

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

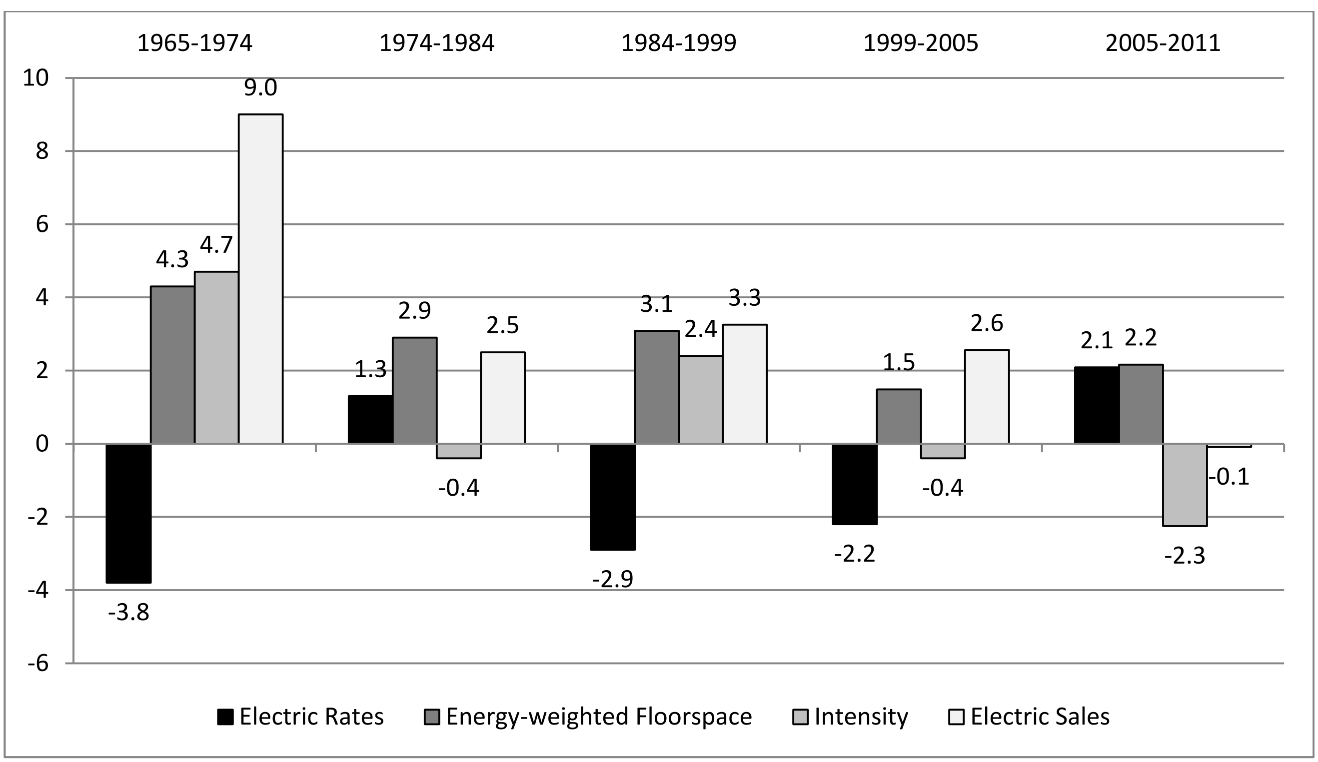
SUFG has two distinct models of commercial electricity sales, econometric and end-use, that have specific strengths and complement each other. SUFG staff developed the econometric model and acquired a proprietary end-use model, Commercial Energy Demand Modeling System (CEDMS). CEDMS is a descendant of 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 1974-1984, which resulted in a decrease in energy intensity. As electricity prices fell again during the 1984-1999 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 1999-2005 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 2005-2011 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

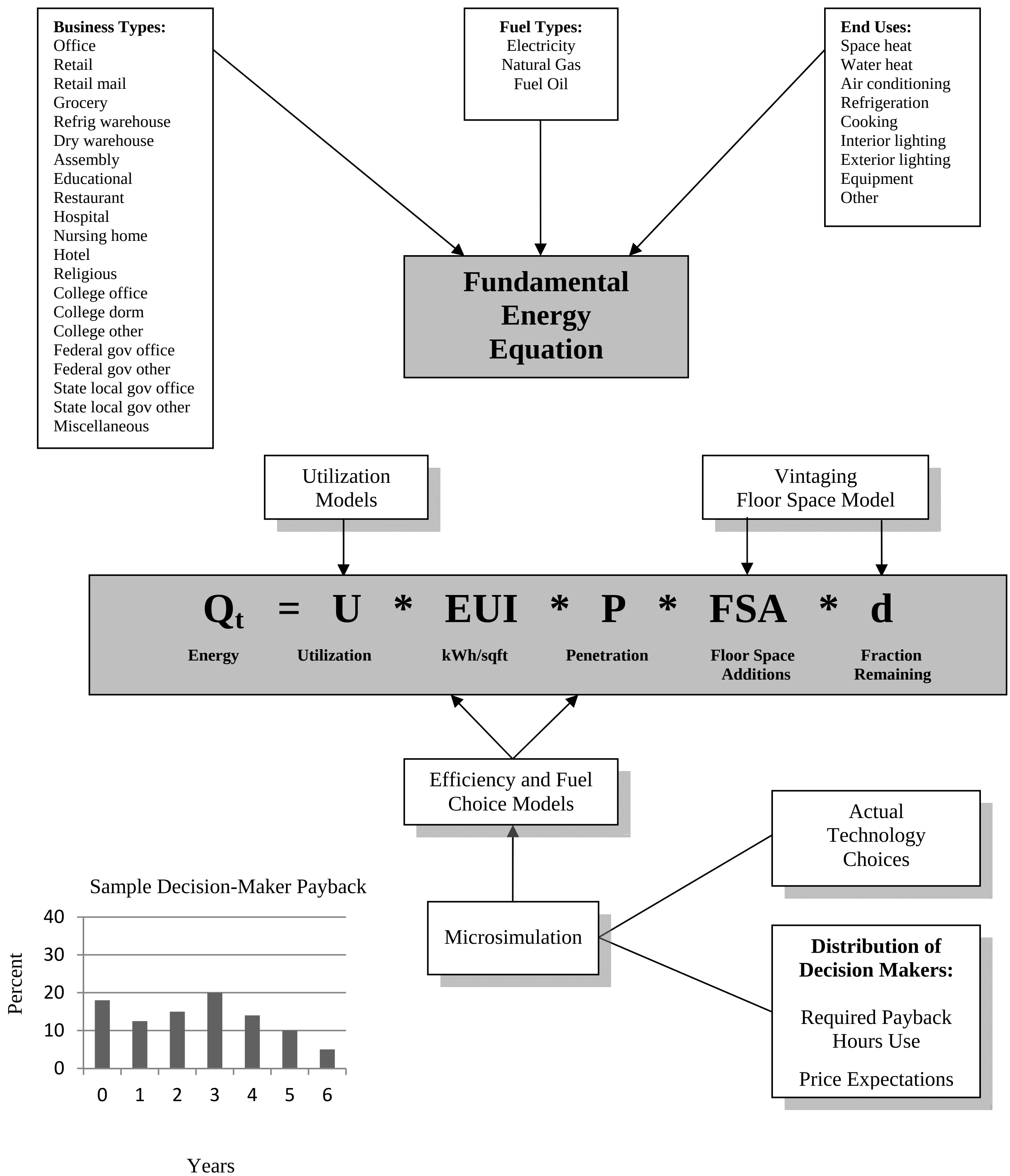
d = fraction of floor space of vintage t still standing in forecast year T.

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 about 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 0.33 percent. The historical and 2013 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 also have a significant effect on electricity sales.

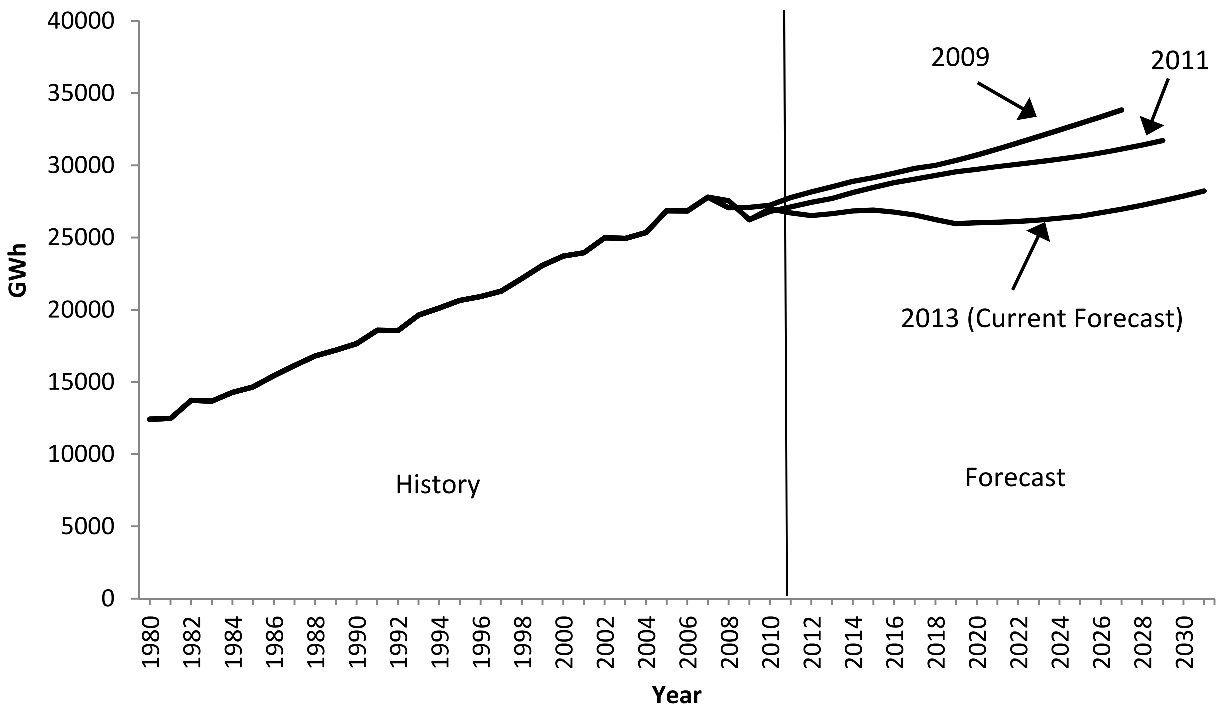
As shown in Figure 6-3, the current projection lies well below both the 2009 and 2011 forecasts. The current projection starts out at about the same level but declines slightly through 2020 before growing moderately afterwards. The slower growth rate is due to a combination of the macroeconomic projections and higher projected commercial sector electricity prices. These factors combined with the impact of utility-sponsored DSM result in the slight decline in the earlier years.

As shown in Table 6-5 and Figure 6-4, the growth rates for the low and high scenarios are about 0.56 percent lower and 0.44 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**
2009	1.18	2008-2027
2011	0.89	2010-2029
2013	0.33	2012-2031

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 (2013 SUFG Scenarios and 2011 Base Forecast)

Forecast	Current Scenario (2012-2031)			2011 Forecast (2010-2029)
	Base	Low	High	Base
Electric Rates	1.43	1.62	1.27	0.87
Natural Gas Price	1.56	1.56	1.56	0.77
Energy-weighted Floor Space	0.90	0.82	0.98	1.18

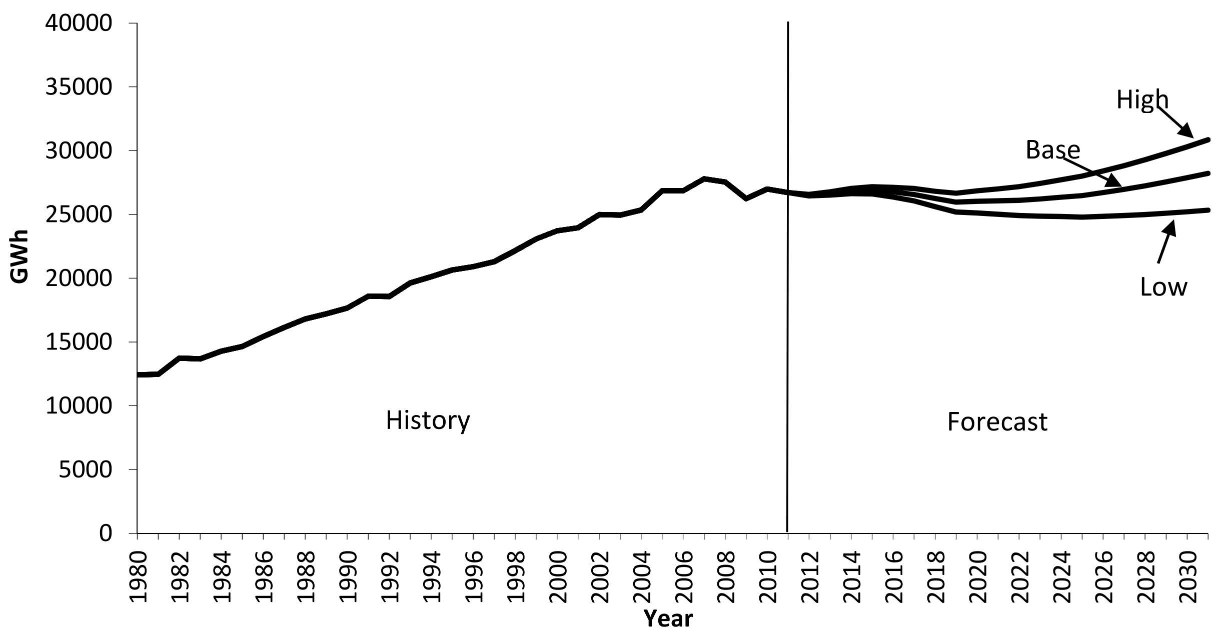
Table 6-4. History of SUFG Commercial Sector Growth Rates (Percent)

Forecast	Electric Energy-weighted Floor Space	Without DSM		With DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2013 SUFG Base (2012-2031)	0.90	-0.07	0.83	-0.57	0.33
2011 SUFG Base (2010-2029)	1.18	-0.23	0.95	-0.29	0.89
2009 SUFG Base (2008-2027)	1.21	0.02	1.23	-0.03	1.18

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

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2012-2031	0.33	-0.23	0.79

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 2023 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. Historical and forecast prices are included in the Appendix of this report.

Figure 6-5. Indiana Commercial Base Real Price Projections (in 2011 Dollars)

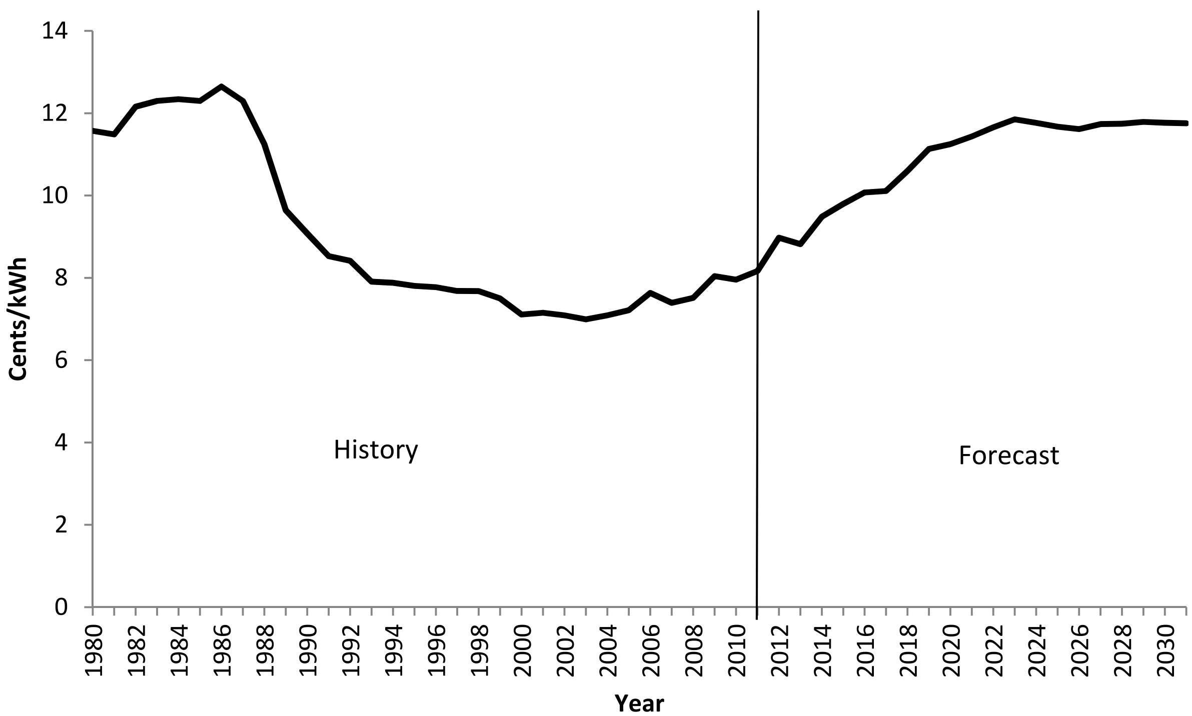


Table 6-6. Indiana Commercial Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	**%**
1980-1985	1.23
1985-1990	-5.88
1990-1995	-2.98
1995-2000	-1.85
2000-2005	0.29
2005-2011	2.09
2012-2031	1.43

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

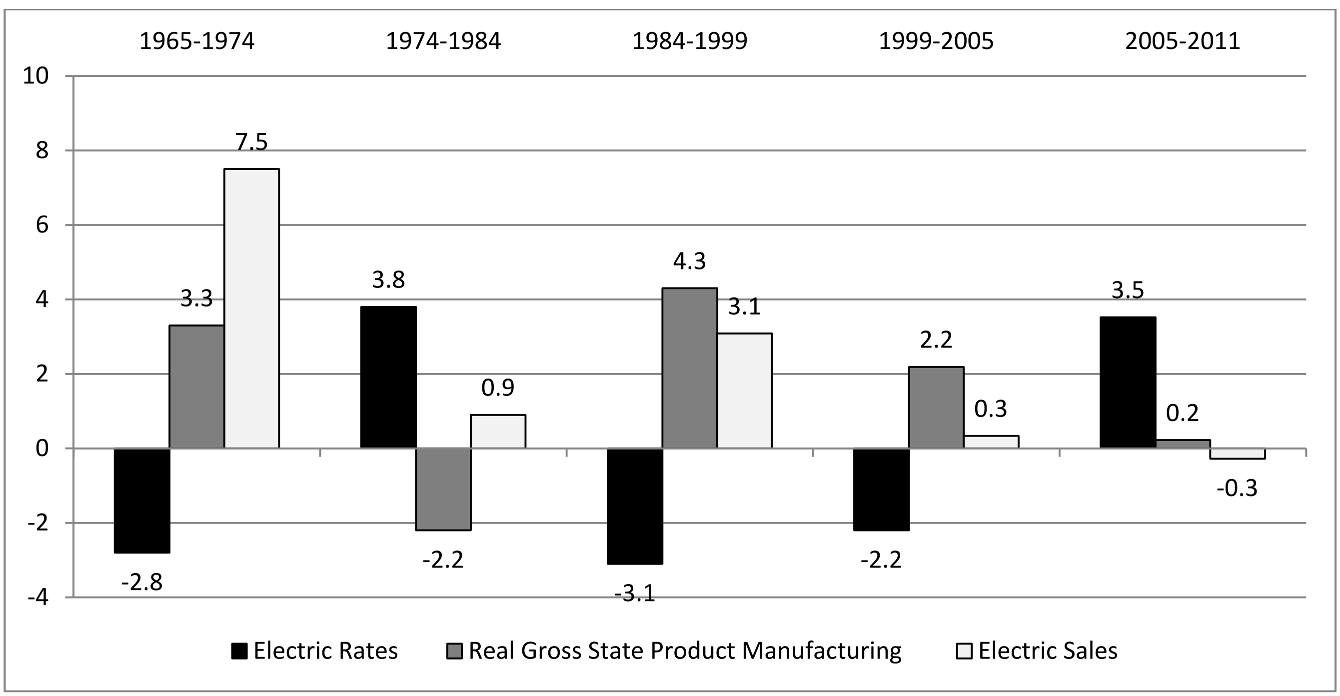
SUFG has used several models to analyze and forecast electricity use in the industrial sector. The primary forecasting model is INDEED, an econometric model developed by the Electric Power Research Institute (EPRI), which is used to model the electricity use of 15 major industry groupings in the state. 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 — 1965-1974, 1974-1984, 1984-1999, 1999-2005, and the more recent period 2005-2011. Figure 7-1 shows state growth rates for real manufacturing product, real electric rates and electric energy sales for the five 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 during 1965-1974 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 1974-1984. 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 1965-1974. 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 1999-2005 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 been very small, and overall growth in industrial electricity has turned slightly negative.

Model Description

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. Over 65 percent of state GSP is accounted for by the following industries: primary metals, 8 percent; fabricated metals, 6 percent; industrial machinery and equipment, 10 percent; chemicals, 16 percent; transportation equipment, 20 percent; and electronic and electric equipment, 5 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 state industrial 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 fifth 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.

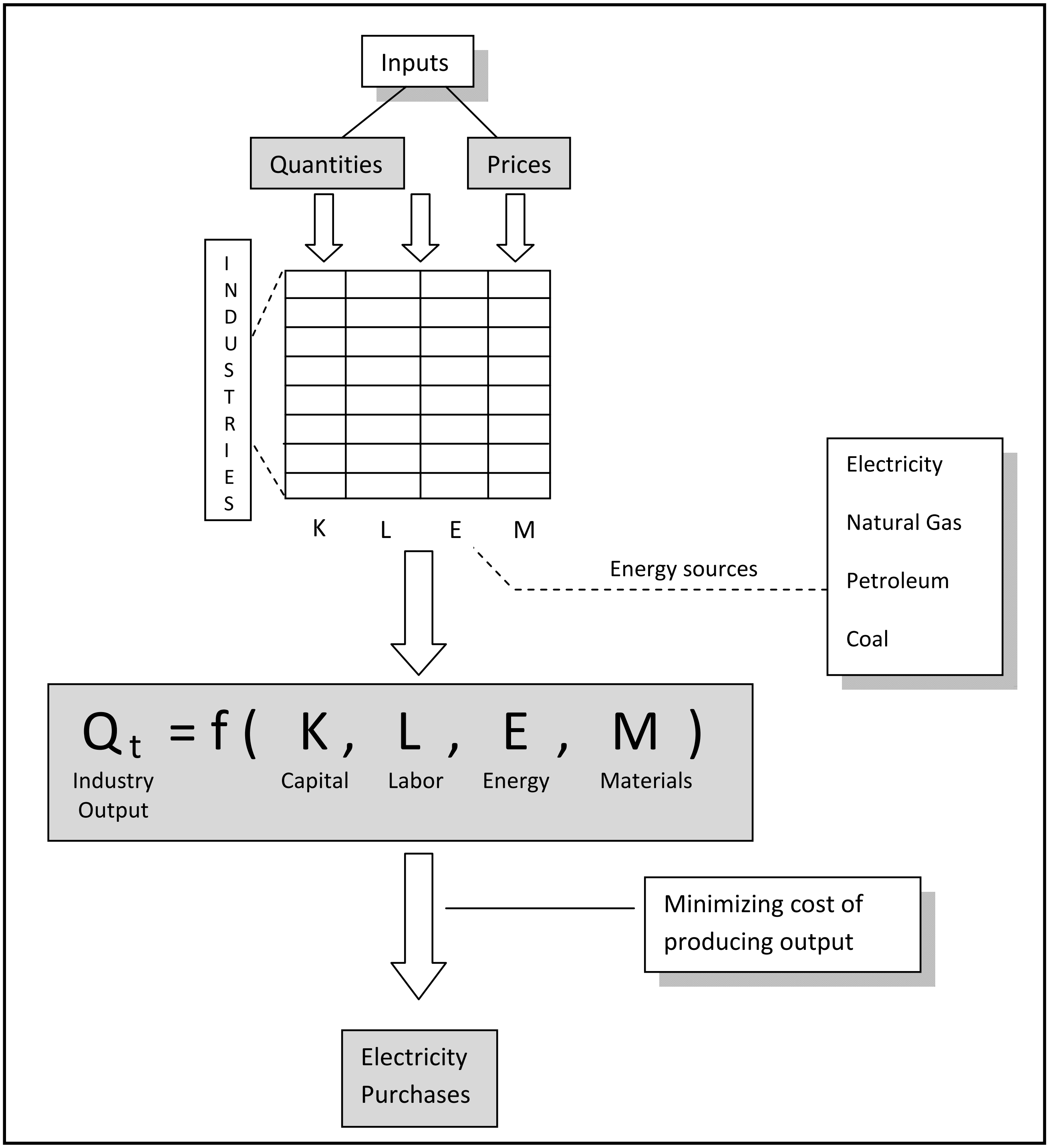
As described earlier in this chapter, INDEED captures the competition between the various inputs for their share of the cost of production by assuming firms seek the mix of inputs that minimize the production cost for a given level of output. Unit costs of natural gas, oil, coal, capital, labor and materials 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 were high in 2008, then declined by about 52 percent by 2012, and are projected to increase at a rate of about 2.4 percent per year over the forecast horizon 2012-2031. Distillate fuel prices were also high in 2008, before falling sharply by 42 percent in 2009, and then rebounding by about 60 percent by 2012. They are projected to decline by about 18 percent by 2014 before increasing at a rate of about 1.6 percent per year over the remainder of the forecast period. 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 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 1.66 percent per year, without DSM, over the forecast horizon.

Table 7-1. Selected Statistics for Indiana's Industrial Sector (Without 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	4.73	5.83	0.58	3.40	-1.16	2.24
24	Lumber & Wood Products	2.63	0.66	0.12	3.40	-0.94	2.45
25	Furniture & Fixtures	3.09	0.47	0.07	1.57	-1.09	0.49
26	Paper & Allied Products	1.83	2.94	0.76	3.40	-0.88	2.52
27	Printing & Publishing	3.44	1.24	0.17	3.40	-2.19	1.21
28	Chemicals & Allied Products	16.41	19.98	0.58	3.40	-1.59	1.81
30	Rubber & Misc. Plastic Products	3.66	5.76	0.74	2.85	-1.03	1.82
32	Stone, Clay, & Glass Products	3.13	5.08	0.77	1.57	-0.77	0.80
33	Primary Metal Products	7.59	27.01	1.68	0.76	0.59	1.35
34	Fabricated Metal Products	5.95	6.39	0.51	3.20	-1.27	1.92
35	Industrial Machinery & Equipment	10.42	4.62	0.21	2.74	-1.20	1.54
36	Electronic & Electric Equipment	5.18	5.87	0.54	0.71	-0.62	0.09
37	Transportation Equipment	20.01	8.97	0.21	3.61	-1.07	2.54
38	Instruments And Related Products	4.20	1.01	0.11	1.57	-1.86	-0.29
39	Miscellaneous Manufacturing	2.27	1.20	0.25	1.57	-3.32	-1.75
Total	Manufacturing	100.00	100.00	0.47	2.86	-1.20	1.66

Figure 7-2. Structure of Industrial Energy Modeling System



Summary of Results

The remainder of this chapter describes SUFG's industrial electricity sales projections. First, the current base projection of industrial 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

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 Electricity Sales Projections

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 2009, 2011, 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 2011 level of approximately 39,000 GWh to almost 50,000 GWh by 2031. This growth rate of 1.29 percent per year is substantially higher than both the 0.33 percent rate projected for the commercial sector and the 0.37 percent rate projected for the residential sector. As shown in Figure 7-3, the current forecast lies below the 2009 forecast. The current forecast also lies below the 2011 forecast after 2014, while being a little higher in the near term, 2012-2013. Like the other sectors, rising real electricity prices coupled with a weak macroeconomic outlook result in a more conservative forecast of electricity use.

Table 7-5 and Figure 7-4 shows how industrial electricity sales differ by scenario. Industrial sales, in the high scenario, are expected to increase to 56,595 GWh by 2031, 13.7 percent higher than the base projection. In the low scenario, industrial sales grow more slowly, which results in 43,609 GWh sales by 2031, 14.1 percent below the base scenario.

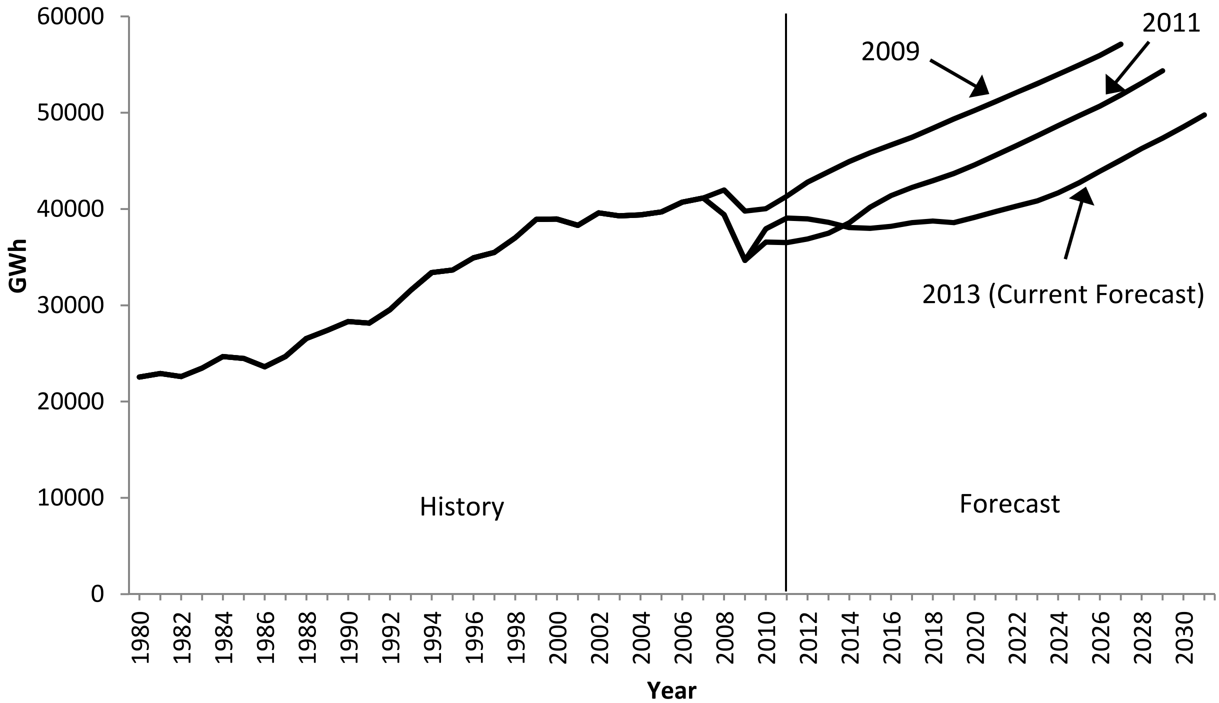
The wide range of forecast sales is caused primarily by the equally wide range of the trajectories of industrial output contained in the CEMR low and high scenarios for the state. In the base scenario GSP in the industrial sector grows 2.86 percent per year during the forecast period. That rate is 3.49 percent in the high scenario and 2.24 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**
2009	1.63	2008-2027
2011	2.11	2010-2029
2013	1.29	2012-2031

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.

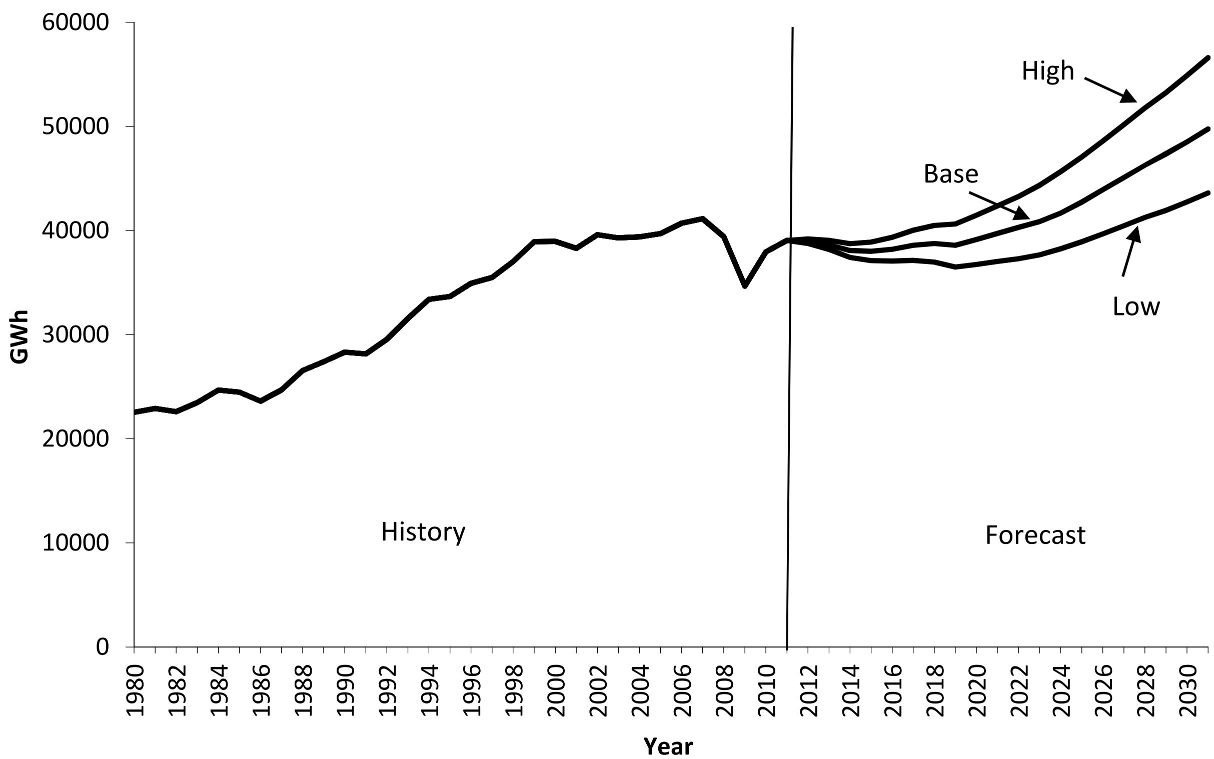
Table 7-4. History of SUFG Industrial Sector Growth Rates (Percent)

Forecast	Output	Mix Effects	Electric Energy-weighted Output	Without DSM		With DSM	
				Intensity	Sales Growth	Intensity	Sales Growth
2013 SUFG Base (2012-2031)	2.86	0.53	3.40	-1.67	1.73	-2.11	1.29
2011 SUFG Base (2010-2029)	3.95	-1.11	2.84	-0.68	2.16	-0.73	2.11
2009 SUFG Base (2008-2027)	2.82	-0.56	2.26	-0.63	1.63	-0.63	1.63

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

Average Compound Growth Rates			
Forecast Period	Base	Low	High
2012-2031	1.29	0.62	1.95

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 until 2023 with the need for additional emissions control equipment and then remain relatively constant. 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 (Cents/kWh in 2011 Dollars)

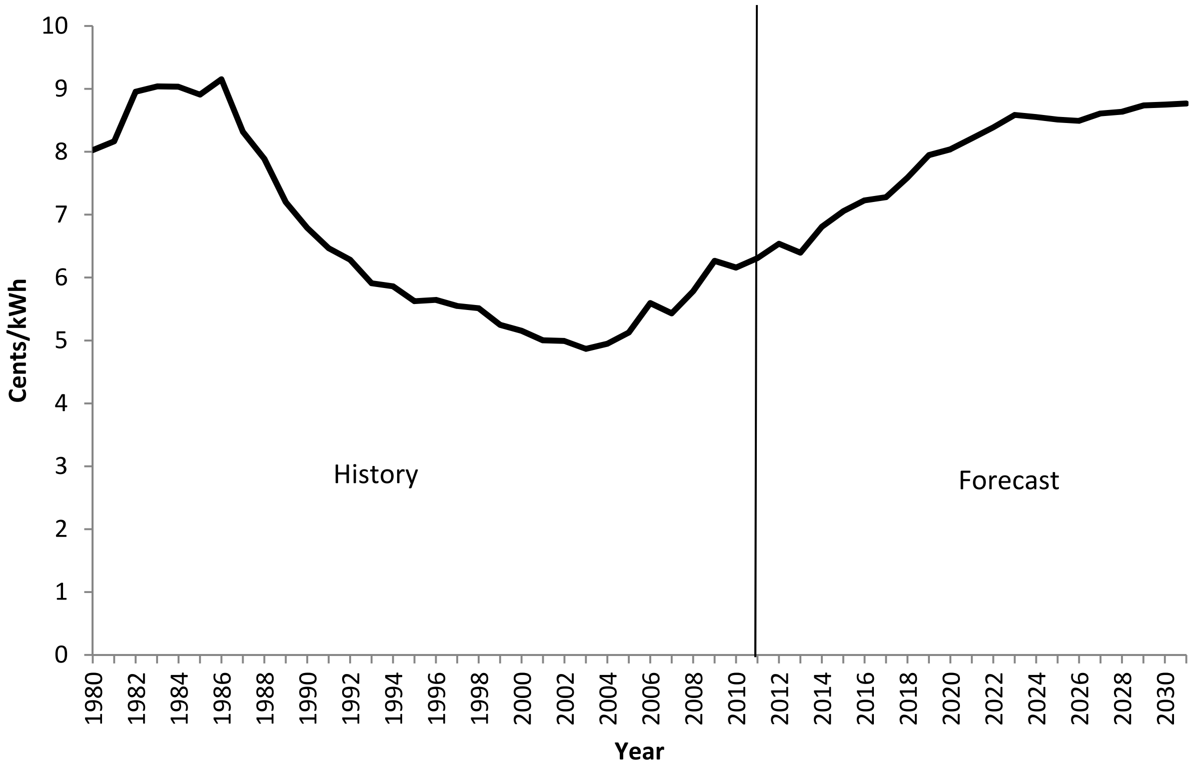


Table 7-6. Indiana Industrial Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	**Percent**
1980-1985	2.11
1985-1990	-5.29
1990-1995	-3.69
1995-2000	-1.73
2000-2005	-0.11
2005-2011	3.52
2012-2031	1.56

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

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. I&M's load is split approximately 85-15 percent between Indiana and Michigan. While the majority of WVPA’s load is in Indiana, 81 percent, it does have members in Illinois, Missouri, and Ohio. WVPA had a member in Michigan at the time of the previous forecast, but that member left at the end of 2011 and, additionally, their Ohio member is leaving at the end of 2014. IMPA has a wholesale member in Ohio although approximately 99 percent of their load is still in Indiana. Hoosier Energy began serving a member cooperative in Illinois in January 2011. Approximately 95 percent of Hoosier’s load is currently in Indiana although that’s expected to decline to approximately 93 percent by 2015. 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 instant. 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. 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 at the 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 2013 Base Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

		Retail Sales						Energy	Summer
Year		Res	Com	Ind	Other	Total	Losses	Required	Demand
Hist	1984	20,153	14,274	24,678	674	59,779	4,185	63,964	11,331
Hist	1985	19,707	14,651	24,480	653	59,491	4,164	63,655	11,030
Hist	1986	20,410	15,429	23,618	610	60,067	4,205	64,271	11,834
Hist	1987	21,154	16,144	24,694	617	62,609	4,383	66,992	12,218
Hist	1988	22,444	16,808	26,546	633	66,431	4,650	71,081	13,447
Hist	1989	22,251	17,205	27,394	661	67,511	4,726	72,237	12,979
Hist	1990	22,037	17,659	28,311	650	68,657	4,806	73,463	13,659
Hist	1991	24,215	18,580	28,141	629	71,564	5,009	76,573	14,278
Hist	1992	22,916	18,556	29,540	619	71,632	5,014	76,646	14,055
Hist	1993	25,060	19,627	31,562	511	76,760	5,373	82,133	14,916
Hist	1994	25,176	20,116	33,395	507	79,193	5,544	84,737	15,010
Hist	1995	26,510	20,646	33,659	510	81,326	5,693	87,019	16,251
Hist	1996	26,833	20,909	34,920	536	83,197	5,824	89,021	16,162
Hist	1997	26,792	21,295	35,499	530	84,116	5,888	90,004	16,021
Hist	1998	27,663	22,166	37,012	520	87,360	6,115	93,476	16,638
Hist	1999	29,180	23,078	38,916	543	91,717	6,420	98,137	17,246
Hist	2000	28,684	23,721	38,957	529	91,890	6,432	98,322	16,738
Hist	2001	29,437	23,953	38,293	526	92,208	6,455	98,663	17,511
Hist	2002	32,363	24,980	39,594	540	97,476	6,823	104,300	18,831
Hist	2003	31,177	24,940	39,285	589	95,992	6,719	102,711	18,794
Hist	2004	31,042	25,351	39,380	644	96,417	6,749	103,166	18,193
Hist	2005	33,691	26,857	39,702	619	100,869	7,061	107,930	19,944
Hist	2006	32,544	26,846	40,707	604	100,701	7,049	107,750	20,855
Hist	2007	35,038	27,793	41,139	646	104,616	7,323	111,939	20,858
Hist	2008	34,177	27,548	39,417	653	101,795	7,126	108,920	19,275
Hist	2009	32,684	26,233	34,657	661	94,235	6,596	100,832	19,054
Hist	2010	34,979	26,988	37,929	694	100,589	7,041	107,631	20,315
Hist	2011	34,109	26,711	39,045	649	100,514	7,036	107,550	21,002
Frcst	2012	33,727	26,520	38,970	649	99,866	7,330	107,196	18,683
Frcst	2013	33,757	26,647	38,619	649	99,672	7,329	107,002	18,481
Frcst	2014	33,773	26,844	38,074	649	99,340	7,310	106,650	18,389
Frcst	2015	33,978	26,900	37,993	649	99,519	7,322	106,841	18,412
Frcst	2016	33,740	26,765	38,205	649	99,359	7,310	106,669	18,452
Frcst	2017	33,473	26,569	38,583	649	99,274	7,303	106,577	18,631
Frcst	2018	33,119	26,244	38,753	649	98,765	7,266	106,032	18,818
Frcst	2019	32,717	25,957	38,588	649	97,910	7,210	105,120	18,975
Frcst	2020	33,256	26,026	39,134	649	99,065	7,299	106,364	19,256
Frcst	2021	33,238	26,058	39,725	649	99,669	7,351	107,021	19,401
Frcst	2022	33,271	26,105	40,302	649	100,327	7,408	107,735	19,528
Frcst	2023	33,343	26,210	40,852	649	101,054	7,470	108,524	19,658
Frcst	2024	33,509	26,346	41,679	649	102,183	7,558	109,740	19,861
Frcst	2025	33,874	26,475	42,728	649	103,727	7,673	111,400	20,147
Frcst	2026	34,255	26,715	43,923	649	105,542	7,809	113,351	20,476
Frcst	2027	34,633	26,963	45,088	649	107,333	7,943	115,276	20,801
Frcst	2028	34,952	27,241	46,275	649	109,116	8,077	117,193	21,099
Frcst	2029	35,285	27,555	47,357	649	110,845	8,208	119,053	21,413
Frcst	2030	35,827	27,877	48,517	649	112,870	8,361	121,231	21,790
Frcst	2031	36,169	28,222	49,762	649	114,802	8,509	123,311	22,138

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
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	0.74	2.47	2.47	2.47	0.59
2000-2005	3.27	2.51	0.38	3.19	1.88	1.88	1.88	3.57
2005-2010	0.75	0.10	-0.91	2.29	-0.06	-0.06	-0.06	0.37
2010-2015	-0.58	-0.07	0.03	-1.32	-0.21	0.78	-0.15	-1.95
2015-2020	-0.43	-0.66	0.59	0.00	-0.09	-0.06	-0.09	0.90
2020-2025	0.37	0.34	1.77	0.00	0.92	1.01	0.93	0.91
2025-2030	1.13	1.04	2.57	0.00	1.70	1.73	1.71	1.58
2030-2031	0.96	1.24	2.57	0.00	1.71	1.77	1.72	1.60
2012-2031	0.37	0.33	1.29	0.00	0.74	0.79	0.74	0.90

SUFG 2013 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	1984	20,153	14,274	24,678	674	59,779	4,185	63,964	11,331
Hist	1985	19,707	14,651	24,480	653	59,491	4,164	63,655	11,030
Hist	1986	20,410	15,429	23,618	610	60,067	4,205	64,271	11,834
Hist	1987	21,154	16,144	24,694	617	62,609	4,383	66,992	12,218
Hist	1988	22,444	16,808	26,546	633	66,431	4,650	71,081	13,447
Hist	1989	22,251	17,205	27,394	661	67,511	4,726	72,237	12,979
Hist	1990	22,037	17,659	28,311	650	68,657	4,806	73,463	13,659
Hist	1991	24,215	18,580	28,141	629	71,564	5,009	76,573	14,278
Hist	1992	22,916	18,556	29,540	619	71,632	5,014	76,646	14,055
Hist	1993	25,060	19,627	31,562	511	76,760	5,373	82,133	14,916
Hist	1994	25,176	20,116	33,395	507	79,193	5,544	84,737	15,010
Hist	1995	26,510	20,646	33,659	510	81,326	5,693	87,019	16,251
Hist	1996	26,833	20,909	34,920	536	83,197	5,824	89,021	16,162
Hist	1997	26,792	21,295	35,499	530	84,116	5,888	90,004	16,021
Hist	1998	27,663	22,166	37,012	520	87,360	6,115	93,476	16,638
Hist	1999	29,180	23,078	38,916	543	91,717	6,420	98,137	17,246
Hist	2000	28,684	23,721	38,957	529	91,890	6,432	98,322	16,738
Hist	2001	29,437	23,953	38,293	526	92,208	6,455	98,663	17,511
Hist	2002	32,363	24,980	39,594	540	97,476	6,823	104,300	18,831
Hist	2003	31,177	24,940	39,285	589	95,992	6,719	102,711	18,794
Hist	2004	31,042	25,351	39,380	644	96,417	6,749	103,166	18,193
Hist	2005	33,691	26,857	39,702	619	100,869	7,061	107,930	19,944
Hist	2006	32,544	26,846	40,707	604	100,701	7,049	107,750	20,855
Hist	2007	35,038	27,793	41,139	646	104,616	7,323	111,939	20,858
Hist	2008	34,177	27,548	39,417	653	101,795	7,126	108,920	19,275
Hist	2009	32,684	26,233	34,657	661	94,235	6,596	100,832	19,054
Hist	2010	34,979	26,988	37,929	694	100,589	7,041	107,631	20,315
Hist	2011	34,109	26,711	39,045	649	100,514	7,036	107,550	21,002
Frcst	2012	33,710	26,453	38,753	649	99,565	7,307	106,871	18,630
Frcst	2013	33,714	26,507	38,179	649	99,050	7,282	106,332	18,371
Frcst	2014	33,643	26,631	37,418	649	98,340	7,235	105,575	18,212
Frcst	2015	33,833	26,600	37,114	649	98,197	7,222	105,419	18,180
Frcst	2016	33,583	26,366	37,060	649	97,658	7,182	104,840	18,158
Frcst	2017	33,278	26,066	37,122	649	97,115	7,142	104,257	18,261
Frcst	2018	32,871	25,607	36,971	649	96,097	7,068	103,165	18,370
Frcst	2019	32,437	25,188	36,496	649	94,770	6,976	101,746	18,449
Frcst	2020	32,949	25,109	36,737	649	95,444	7,029	102,473	18,650
Frcst	2021	32,890	25,014	37,029	649	95,582	7,047	102,629	18,717
Frcst	2022	32,892	24,907	37,290	649	95,738	7,066	102,804	18,761
Frcst	2023	32,955	24,857	37,658	649	96,120	7,099	103,219	18,835
Frcst	2024	33,091	24,832	38,240	649	96,812	7,152	103,964	18,965
Frcst	2025	33,427	24,787	38,918	649	97,781	7,225	105,007	19,158
Frcst	2026	33,778	24,842	39,680	649	98,949	7,313	106,262	19,381
Frcst	2027	34,102	24,906	40,457	649	100,114	7,401	107,515	19,602
Frcst	2028	34,365	24,987	41,255	649	101,257	7,487	108,744	19,794
Frcst	2029	34,638	25,092	41,931	649	102,310	7,569	109,879	19,995
Frcst	2030	35,157	25,203	42,739	649	103,748	7,677	111,425	20,277
Frcst	2031	35,450	25,329	43,609	649	105,037	7,776	112,813	20,519

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
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	0.74	2.47	2.47	2.47	0.59
2000-2005	3.27	2.51	0.38	3.19	1.88	1.88	1.88	3.57
2005-2010	0.75	0.10	-0.91	2.29	-0.06	-0.06	-0.06	0.37
2010-2015	-0.66	-0.29	-0.43	-1.32	-0.48	0.51	-0.41	-2.20
2015-2020	-0.53	-1.15	-0.20	0.00	-0.57	-0.54	-0.57	0.51
2020-2025	0.29	-0.26	1.16	0.00	0.49	0.55	0.49	0.54
2025-2030	1.01	0.33	1.89	0.00	1.19	1.22	1.19	1.14
2030-2031	0.83	0.50	2.03	0.00	1.24	1.29	1.25	1.19
012-2031	0.27	-0.23	0.62	0.00	0.28	0.33	0.29	0.51

SUFG 2013 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	1984	20,153	14,274	24,678	674	59,779	4,185	63,964	11,331
Hist	1985	19,707	14,651	24,480	653	59,491	4,164	63,655	11,030
Hist	1986	20,410	15,429	23,618	610	60,067	4,205	64,271	11,834
Hist	1987	21,154	16,144	24,694	617	62,609	4,383	66,992	12,218
Hist	1988	22,444	16,808	26,546	633	66,431	4,650	71,081	13,447
Hist	1989	22,251	17,205	27,394	661	67,511	4,726	72,237	12,979
Hist	1990	22,037	17,659	28,311	650	68,657	4,806	73,463	13,659
Hist	1991	24,215	18,580	28,141	629	71,564	5,009	76,573	14,278
Hist	1992	22,916	18,556	29,540	619	71,632	5,014	76,646	14,055
Hist	1993	25,060	19,627	31,562	511	76,760	5,373	82,133	14,916
Hist	1994	25,176	20,116	33,395	507	79,193	5,544	84,737	15,010
Hist	1995	26,510	20,646	33,659	510	81,326	5,693	87,019	16,251
Hist	1996	26,833	20,909	34,920	536	83,197	5,824	89,021	16,162
Hist	1997	26,792	21,295	35,499	530	84,116	5,888	90,004	16,021
Hist	1998	27,663	22,166	37,012	520	87,360	6,115	93,476	16,638
Hist	1999	29,180	23,078	38,916	543	91,717	6,420	98,137	17,246
Hist	2000	28,684	23,721	38,957	529	91,890	6,432	98,322	16,738
Hist	2001	29,437	23,953	38,293	526	92,208	6,455	98,663	17,511
Hist	2002	32,363	24,980	39,594	540	97,476	6,823	104,300	18,831
Hist	2003	31,177	24,940	39,285	589	95,992	6,719	102,711	18,794
Hist	2004	31,042	25,351	39,380	644	96,417	6,749	103,166	18,193
Hist	2005	33,691	26,857	39,702	619	100,869	7,061	107,930	19,944
Hist	2006	32,544	26,846	40,707	604	100,701	7,049	107,750	20,855
Hist	2007	35,038	27,793	41,139	646	104,616	7,323	111,939	20,858
Hist	2008	34,177	27,548	39,417	653	101,795	7,719	108,920	19,275
Hist	2009	32,684	26,233	34,657	661	94,235	7,619	100,832	19,054
Hist	2010	34,979	26,988	37,929	694	100,589	7,620	107,631	20,315
Hist	2011	34,109	26,711	39,045	649	100,514	7,621	107,550	21,002
Frcst	2012	33,737	26,579	39,199	649	100,163	7,352	107,515	18,735
Frcst	2013	33,778	26,772	39,061	649	100,261	7,374	107,634	18,583
Frcst	2014	33,746	27,046	38,736	649	100,176	7,374	107,550	18,528
Frcst	2015	33,967	27,173	38,883	649	100,672	7,409	108,082	18,604
Frcst	2016	33,731	27,112	39,357	649	100,849	7,424	108,273	18,699
Frcst	2017	33,478	27,027	40,021	649	101,175	7,448	108,622	18,944
Frcst	2018	33,152	26,813	40,486	649	101,100	7,444	108,544	19,197
Frcst	2019	32,796	26,664	40,619	649	100,728	7,423	108,151	19,435
Frcst	2020	33,360	26,851	41,468	649	102,328	7,545	109,873	19,788
Frcst	2021	33,364	26,998	42,357	649	103,368	7,631	110,999	20,006
Frcst	2022	33,424	27,178	43,264	649	104,515	7,725	112,240	20,214
Frcst	2023	33,554	27,426	44,348	649	105,976	7,838	113,814	20,466
Frcst	2024	33,757	27,718	45,648	649	107,773	7,974	115,747	20,779
Frcst	2025	34,152	28,008	47,058	649	109,867	8,131	117,998	21,155
Frcst	2026	34,569	28,406	48,582	649	112,206	8,307	120,513	21,571
Frcst	2027	34,988	28,824	50,163	649	114,624	8,489	123,112	21,999
Frcst	2028	35,345	29,287	51,769	649	117,049	8,671	125,720	22,408
Frcst	2029	35,727	29,784	53,251	649	119,410	8,850	128,260	22,836
Frcst	2030	36,322	30,307	54,885	649	122,162	9,058	131,220	23,344
Frcst	2031	36,702	30,859	56,595	649	124,805	9,258	134,063	23,819

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
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	0.74	2.47	2.47	2.47	0.59
2000-2005	3.27	2.51	0.38	3.19	1.88	1.88	1.88	3.57
2005-2010	0.75	0.10	-0.91	2.29	-0.06	1.54	-0.06	0.37
2010-2015	-0.59	0.14	0.50	-1.32	0.02	-0.56	0.08	-1.74
2015-2020	-0.36	-0.24	1.30	0.00	0.33	0.36	0.33	1.24
2020-2025	0.47	0.85	2.56	0.00	1.43	1.51	1.44	1.34
2025-2030	1.24	1.59	3.12	0.00	2.14	2.18	2.15	1.99
2030-2031	1.05	1.82	3.12	0.00	2.16	2.22	2.17	2.03
2012-2031	0.44	0.79	1.95	0.00	1.16	1.22	1.17	1.27

Indiana Base Average Retail Rates (Cents/kWh) (in 2011 Dollars)

Year	Res	Com	Ind	Average
1984	12.97	12.34	9.03	11.05
1985	13.28	12.30	8.91	11.08
1986	13.45	12.65	9.15	11.42
1987	12.96	12.30	8.32	10.80
1988	12.20	11.25	7.89	10.09
1989	11.39	9.64	7.20	9.09
1990	10.73	9.08	6.79	8.53
1991	10.07	8.53	6.47	8.12
1992	9.98	8.42	6.28	7.91
1993	9.41	7.90	5.91	7.46
1994	9.44	7.88	5.86	7.40
1995	9.27	7.80	5.63	7.26
1996	9.24	7.77	5.65	7.23
1997	9.41	7.68	5.55	7.20
1998	9.43	7.68	5.51	7.18
1999	9.15	7.50	5.25	6.94
2000	8.78	7.11	5.15	6.68
2001	8.60	7.15	5.00	6.61
2002	8.43	7.09	4.99	6.57
2003	8.39	6.99	4.87	6.47
2004	8.43	7.09	4.95	6.55
2005	8.44	7.21	5.13	6.71
2006	9.04	7.64	5.59	7.16
2007	8.67	7.39	5.43	6.96
2008	9.00	7.51	5.78	7.25
2009	9.55	8.04	6.27	7.83
2010	9.34	7.96	6.16	7.68
2011	9.68	8.17	6.31	7.86
2012	10.84	8.97	6.54	8.53
2013	10.67	8.82	6.39	8.39
2014	11.65	9.49	6.81	9.06
2015	12.11	9.79	7.05	9.39
2016	12.47	10.07	7.23	9.64
2017	12.44	10.11	7.28	9.63
2018	13.01	10.60	7.59	10.04
2019	13.65	11.13	7.95	10.52
2020	13.72	11.25	8.04	10.61
2021	13.90	11.43	8.21	10.76
2022	14.12	11.66	8.39	10.94
2023	14.29	11.85	8.59	11.10
2024	14.19	11.77	8.55	11.01
2025	14.08	11.67	8.51	10.92
2026	14.00	11.61	8.49	10.84
2027	14.08	11.73	8.61	10.92
2028	14.05	11.74	8.64	10.90
2029	14.05	11.79	8.73	10.94
2030	14.01	11.76	8.75	10.91
2031	13.96	11.76	8.77	10.88
Average Compound Growth Rates (%)				
Year-Year	**Res**	**Com**	**Ind**	**Average**
1985-1990	-4.17	-5.88	-5.29	-5.10
1990-1995	-2.88	-2.98	-3.69	-3.16
1995-2000	-1.09	-1.85	-1.73	-1.66
2000-2005	-0.79	0.29	-0.11	0.09
2005-2010	2.06	1.98	3.74	2.73
2010-2015	5.33	4.25	2.75	4.11
2015-2020	2.54	2.81	2.65	2.47
2020-2025	0.52	0.74	1.15	0.57
2025-2030	-0.11	0.16	0.55	-0.01
2030-2031	-0.31	-0.07	0.20	-0.27
2012-2031	1.34	1.43	1.56	1.29

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
CC	Combined Cycle
CEDMS	Commercial Energy Demand Modeling System
CEMR	Center for Econometric Model Research
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
DLC	Direct Load Control
DOE	U. S. Department of Energy
DR	Demand Response
DSM	Demand-Side Management
EE	Energy Efficiency
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GSP	Gross State Product
GWh	Gigawatt-hour
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	Kilowatt-hour
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
SIC	Standard Industrial Classification
SUFG	State Utility Forecasting Group
WVPA	Wabash Valley Power Association