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FOREWORD

This report presents the 1999 projections of future electricity requirements for the state of Indiana for the period 1997-2016. It also presents a forecast of the likely trajectory of retail electricity prices if the Indiana electricity industry is restructured to allow competition at the generation level.

This study is part of an ongoing effort of independent electricity forecasts 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 seventh 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. The commission shall use the methodology that the forecasting group devises as its primary methodology in developing and keeping current its:*
>
> *(1) analysis of the long range needs for expansion of facilities for the generation of electricity...*
>
> *(2) plan for meeting the future requirements of electricity...*

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

- American Electric Power/Indiana Michigan Power Company;
- Indianapolis Power & Light Company;
- Northern Indiana Public Service Company;
- CINergy;
- Southern Indiana Gas & Electric Company;
- Hoosier Energy Rural Electric Cooperative, Inc;.
- Indiana Municipal Power Agency;
- Wabash Valley Power Association;
- Indiana Industrial Energy Consumers, Inc.;
- Office of the Utility Consumer Counselor;
- Citizen's Action Coalition; and
- Kenneth Scheeringa, State Climatologist.

Finally, the authors would like to gratefully acknowledge the Indiana Utility Regulatory Commission for their input and suggestions toward this forecast. We would especially like to express our gratitude to Robert Glazier, Brad Borum, Helen Caldwell, Laura Cvengros, Dave Johnston, Larry Keppler, Karen McGuinness, Bob Pauley and Jerry Webb.

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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MAJOR CONCLUSIONS

- ✔ *There is growing concern over the developing shortage of Indiana utility controlled generation capacity. SUFG expects the statewide reserve margin to fall below 15 percent this year when the generation deficit (including 15 percent reserves) is expected to be 400 MW, or about 2 percent of Indiana's current generating capacity.*

- ✔ *If, as the forecast predicts, electricity sales and peak demand grow at 1.8 percent per year (down from 2 percent in the 1996 forecast), SUFG projects the need for 2250 MW of new capacity by 2005, and an additional 5400 MW by 2016, the end of the forecast horizon.*

- ✔ *If the current regulatory framework is unchanged over the forecast horizon, SUFG predicts real (inflation adjusted) prices to fall at a rate of slightly less than 1 percent per year until 2003, when prices level out until the end of the forecast horizon when they are expected to increase slightly.*

- ✔ *If, on the other hand, Indiana chose to allow competition among generators and competition works perfectly, SUFG would initially expect market clearing prices to drop below the level of prices that would prevail if regulation were to continue. SUFG would then expect competitive prices to rise quite rapidly as demand growth increases until such prices reach a point where new units are added at the long-run cost of electricity, which is slightly above the mid-term price under continued regulation.*

- ✔ *However, SUFG is doubtful that electricity markets will work perfectly; hence, the competitive price forecast should be considered as a lower limit on likely prices if competition is introduced. If market power is exercised by sellers, actual prices are not likely to be lower and could very likely be higher than those expected with perfect competition.*

- ✔ *In the long run, after the transition from regulation to competition is complete, SUFG would expect prices with competition to be lower than prices with continued regulation, as electricity generators are provided with greater incentives to reduce costs.*

CHAPTER 1
EXECUTIVE SUMMARY

Overview

The State Utility Forecasting Group's (SUFG) 1999 forecast, the seventh such forecast since the group's inception in 1985, continues to predict declines in Indiana real electricity prices if the current regulatory framework is left intact. However, if Indiana and the surrounding Midwest states change the framework, or restructure, to allow competition for customer demand by setting up a Midwest power exchange, free of excess market power, SUFG predicts real prices to fall to even lower levels, and then slowly rise to levels above those that would prevail if the generation sector continued to be regulated.

The assumption that markets are free of excess market power is unlikely to hold during peak periods of demand when only a few suppliers remain with uncommitted generating capacity. Therefore, SUFG, along with many other research groups around the country, is developing a forecasting methodology that allows the possibility of prices reflecting the scarcity value of electricity, e.g., the premium over marginal cost consumers are willing to pay, during such intervals.

In the long run, as construction of new power plants to meet growing demand in a competitive environment begins in earnest, a different situation prevails. SUFG believes the competitive price will again fall below the price that would prevail under continued regulation as electricity generators are provided with greater incentives to reduce cost.

Other issues addressed in this forecast include:

- Can Indiana maintain its competitive advantage in electricity if it chooses not to restructure?
- Are the recent price spikes that occurred in the summer of 1998 in electricity wholesale markets proof positive of market power being exercised by suppliers?
- Is there sufficient firm capacity accessible to Indiana utilities to maintain adequate reserve margins in the next few years?
- Will natural gas displace coal as the fuel of choice for new generating units in Indiana?
- What will be the impact of the Environmental Protection Agency's (EPA) proposed nitrogen oxide (NO_X) rules[1] on Indiana rate payers?

As public debate on restructuring continues, it will become clearer which of the many restructuring scenarios, if any, will evolve from concept to legislative reality. SUFG's strategy will be to continue to provide accurate, timely and useful input to decision makers in Indiana. If the industry restructures to allow competitive pricing of the generation of electricity, SUFG's price prediction systems can be used to measure the impact of restructuring and to estimate the magnitude of any resultant stranded costs or benefits.

Outline of the Report

The current forecast continues to respond to SUFG's legislative mandate to forecast electricity demand. However, with competition and customer choice dominating public debate, the forecast gives added emphasis to what was in the past essentially a by-product of the forecasting system — the expected trajectory of electricity *prices*.

Chapter 2 summarizes the two modeling systems SUFG uses to develop its projections. The first system is used to predict prices and the need for new generating capacity if the current method of regulation is maintained in the future. The second system is used to

[1]In May 1999, the U.S. Court of Appeals in Washington, D.C. ruled that the proposed rules were not legal. At the time this report was issued, the status of an appeal, if any, was unknown.

predict prices with restructuring of the electricity generation industry.

Chapters 3 through 8 describe the data inputs and integrated projections of electricity demand, supply and price for each major consumption sector in the state under three scenarios, all within the traditional regulatory framework:

- 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.

In Chapter 9, the second modeling system is described. It predicts what electricity prices might be if a competitive market in the generation of electricity was established while still maintaining rate base pricing for transmission and distribution. The scenarios that have been developed under this framework are intended to capture the effects of the industry's movement toward market-based restructuring and the impact on prices of export trade to jurisdictions outside the Midwest trading area.

Chapter 9 also describes ongoing work in SUFG and elsewhere that attempts to answer an obvious question -- what will happen to electricity rates if restructuring takes place, but for whatever reason, effective competition is absent? In particular, what if there are too few firms supplying electricity to assure that hourly prices will be bid down to the cost of the most expensive unit dispatched in that hour?

Finally, Chapter 10 discusses the other five issues of importance to Indiana electricity policymakers described on page 1-1.

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, which include new generation capacity, purchased capacity, demand-side management, etc., reflect "need" from both a statewide and utility perspective.

Resource needs are determined on a statewide basis by matching existing statewide resources to projected diversified statewide peak demand plus reserves. For planning purposes, SUFG assumed a 15 percent reserve margin[2] for the state. Due to diversity in demand among the utilities, a statewide 15 percent reserve margin occurs when individual utility reserve margins are roughly 11 percent. When the state reserve margin falls below 15 percent, resource additions are chosen from a list of resource options based on an analysis of load versus existing capacity for individual utilities.

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

Capacity Margin = [(Capacity - Demand)/Capacity] Reserve Margin = [(Capacity - Demand)/Demand]

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

Major Forecast Assumptions

In updating the modeling system to produce the current forecast, new projections were developed for all major exogenous variables. 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 1998 projections for its base scenario. A major input to CEMR's Indiana model is a projection of total U.S. employment, which is derived from CEMR's model of the U.S. economy. The CEMR Indiana projections are based on a national employment projection of 1.21 percent growth per year over the forecast period. Indiana total employment is projected to grow at an average annual rate of 1.00 percent. Other key economic projections follow:

- Real personal income (the residential sector model driver) is expected to grow at a 1.85 percent annual rate.
- Non-manufacturing employment (the commercial sector model driver) is expected to average 1.47 percent annual growth rate over the forecast horizon.
- Despite the continued decline of manufacturing employment, manufacturing Gross State Product (GSP) (the industrial sector model driver) is expected to rise at a 1.61 percent annual rate as gains in productivity offset declines in employment.

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

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

The SUFG forecasting system includes a housing model that utilizes population and income assumptions to project the number of households. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of slightly less than 0.7 percent over the forecast period.

Fossil Fuel Price Projections. All SUFG projections are in terms of real prices, i.e., projections with the effect of inflation removed. SUFG's current assumptions are based on EIA's December 1997 projections for the East North Central Region. SUFG's fossil fuel real price projections are as follows:

- *Natural Gas Prices*: An annual decline of about 2.5 percent per year through 2000 with nearly constant prices thereafter for residential, commercial and industrial customers. However, the projections for electric utility gas prices fall by over 3.5 percent per year by 2000, but increase at 3.6 percent per year thereafter.
- *Utility Price of Coal*: An annual decrease of 1.69 percent through the year 2000 and a 0.94 percent annual decrease from the year 2000 through the end of the forecast horizon.

The Base Scenario with Continued Regulation

As shown in Figure 1-1,[3] Indiana's total electricity requirements under the base scenario are expected to increase from 90,000 gigawatthours (GWh) (one GWh equals one million kilowatthours (kWh)) to nearly 128,000 GWh by 2016, the last year of the forecast period. The annual growth rate in electric sales is approximately 1.8 percent. This is slightly lower than the rate projected in 1996, but within the range of previous SUFG base projections.

The SUFG forecast of electricity sales growth varies by sector. Commercial sales are expected to increase most rapidly at 2.25 percent per year. This is followed by residential sales at 1.67 percent and industrial sales at 1.64 percent.

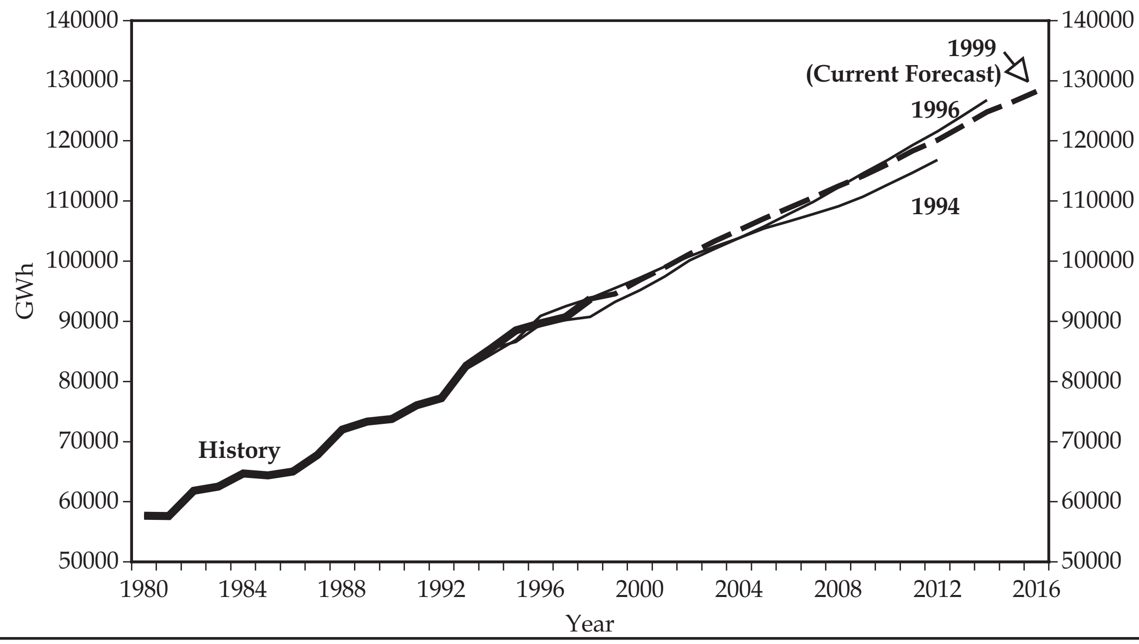
As shown in Figure 1-2, the current forecast of peak demand is also between the previous 1994 and 1996 forecasts throughout the forecast horizon.

Demand-Side Resources

This is the fourth time that SUFG has projected the impact of demand-side management (DSM) programs on electricity sales, peak demand requirements and electricity prices. DSM includes traditional utility-sponsored programs designed to influence customers' usage in ways that produce desirable changes in a

FIGURE 1-1

Indiana Electricity Requirements in GWh (History, Current and Previous SUFG Base Forecasts)



[3]Due to the long period of time needed to collect and input annual data for Indiana utilities and the time needed to develop the forecast, SUFG models were calibrated to 1996 data. The growth rates presented in the text and figures refer to the time period 1996 through 2016 unless otherwise stated. Subsequent to the development of the forecast, annual data for 1997 and 1998 were obtained and these data are included in the history presented in the figures.

utility's load shape. DSM typically excludes interruptible loads.

This forecast estimates that DSM programs have reduced 1996 Indiana peak demand by about 120 Megawatts (MW), or slightly under one percent. DSM impacts are projected to grow to around 150 MW by 2000 and then remain fairly constant for the next decade.

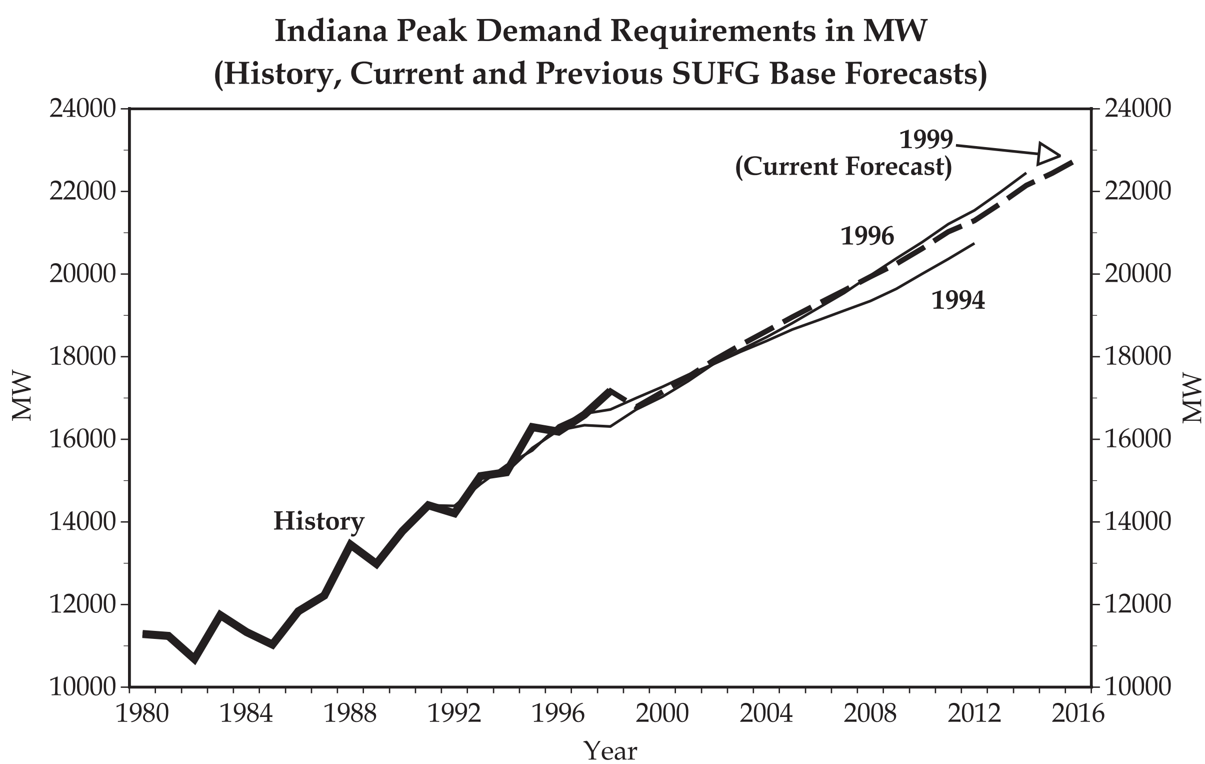
These DSM impacts are substantially lower than those shown in SUFG's previous forecast. Those projected impacts ranged from approximately 200 MW in 1994 to nearly 950 MW in 2014. The reduction in DSM is a result of utilities scaling back both the number of DSM programs and the projected impacts of the remaining programs.

Approximately 520 MW, or about three percent of the current Indiana peak demand, are classified as interruptible. Projections of interruptible load have increased slightly from the previous forecast.

Supply-Side Resources

Supply-side resources include purchases from out-of-state utilities, non-utility generation and utility-owned generation facilities. All currently committed capacity changes are included in SUFG's resource plans. Committed capacity changes include: certified generation additions, retirements, deratings due to scrubber retrofits and net changes in firm out-of-state purchases and sales. Generic generating units are added as necessary during the forecast period to maintain a 15 percent statewide reserve margin. SUFG does not attempt to forecast long-term out-of-state contracts other than those currently planned, nor does it attempt to predict what fraction of new capacity needs is to be met by purchases from outside Indiana.

FIGURE 1-2



Resource Needs

Figure 1-3 illustrates a situation of increasing concern to energy analysts, not only in Indiana, but everywhere -- *the declining ability of our nation's electricity generation system to meet system peak demands in the near future.*

The existing resources in Figure 1-3 include the impacts of current firm purchase/sale contracts between Indiana and non-Indiana utilities. Also included are scheduled future retirements of generating units.

The figure shows that in the summer of 1999, Indiana will be roughly 400 MW short of meeting the 15 percent statewide reserve margin used in the forecast. Unless new capacity is acquired, this deficit is predicted to grow to over 2000 MW by 2005 and to almost 4000 MW by 2010. In calculating the deficit, SUFG did not include the approximately 2330 MW of new generation projects listed in Table 1-1 that have either been publicly announced or for which petitions have been filed with the Indiana Utility Regulatory Commission (IURC).

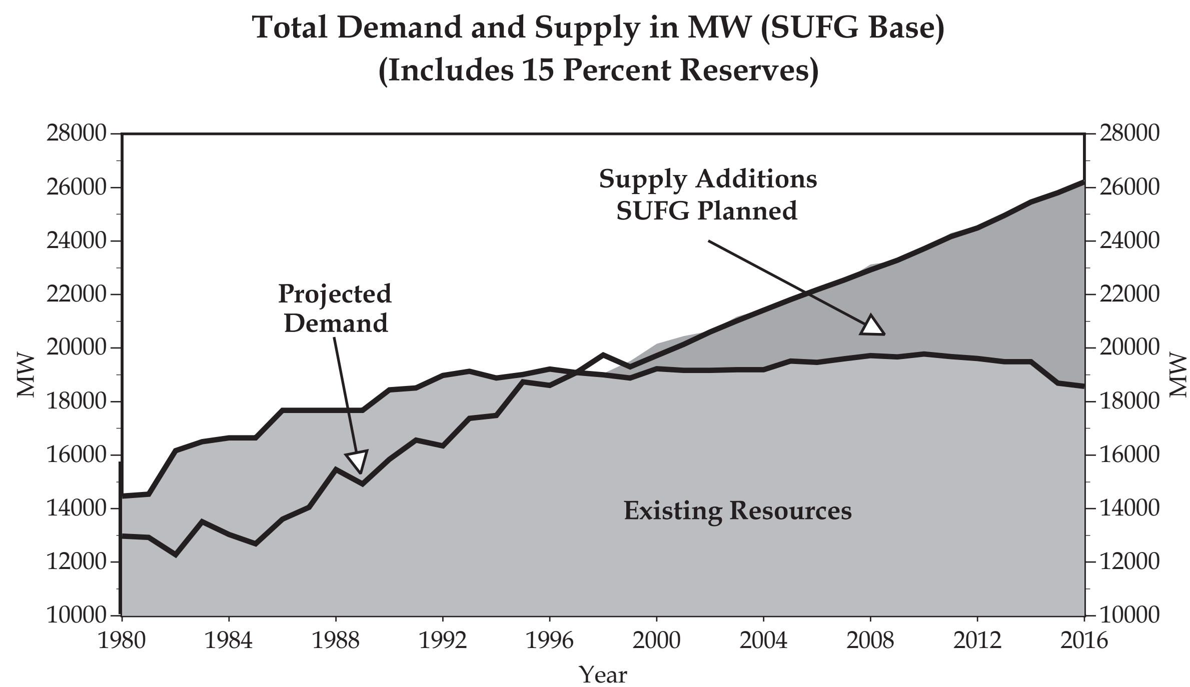
The reasons for excluding this capacity are threefold. First, sufficient information on the projects was not available as the forecast was being developed. Second, it is unlikely that any of the projects will be operational in time for the summer 1999 demand period. Finally, the proposed generators would be un-

TABLE 1-1

Proposed New Generation in Indiana

Owner	MW
SIGECO (General Electric Co-Generation Facility)	42
Amoco/Whiting Refinery	550
IPL	200
AES Greenfield	400
Duke Energy Vermillion	640
Enron	500

FIGURE 1-3



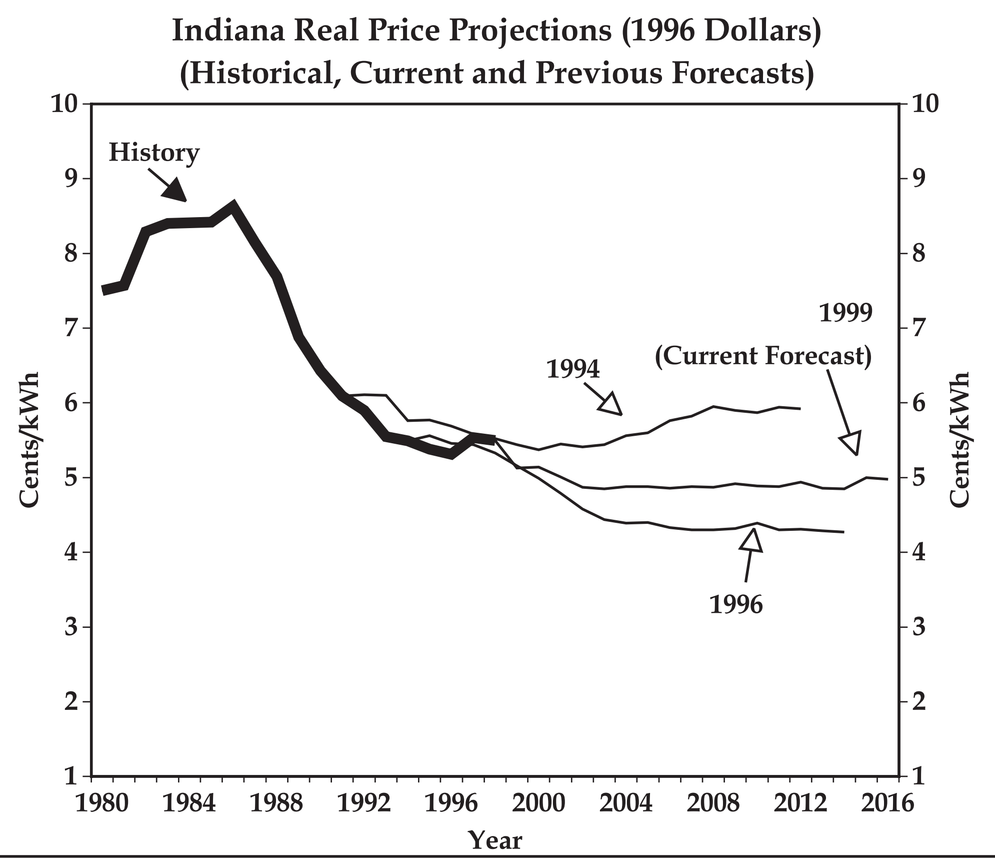
der no obligation to be used to satisfy demand in Indiana. Conversely, projects announced at out-of-state locations may well be used to satisfy Indiana demand if it is profitable to do so.

Electricity Price Projections

The equilibrium real price[4] projections for the base scenario from SUFG's 1999 forecast , as well as the two previous forecasts, are shown in Figure 1-4. Here, average prices are calculated by taking the electric energy-weighted average of residential, commercial, and industrial rates for Indiana's five investor-owned utilities (IOUs).

The period from 1980 to 1985 was characterized by rising real electricity prices as Indiana ratepayers were required to pay for new facilities that, in retrospect, were not needed at the time (Indiana's reserve margin reached 50 percent in 1985). Since their peak in 1986, real electricity prices in Indiana have fallen by 4.7 percent per year. The base scenario projects a further drop of 0.9 percent per year until the year 2003.

FIGURE 1-4



[4] 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).

This is largely due to the projected decline in the price of coal delivered to Indiana utilities. Prices are expected to remain at this level and then increase slightly through the remainder of the forecast horizon. This increase is due to the new generation resources that will be necessary to meet the increasing demand for electricity.

The 1999 forecast is midway between the price forecasts contained in the 1994 scenario base and the Lower Construction Cost (LCC) scenario from the 1996 report. It is almost identical to the price forecast for the 1996 base scenario. (For further details, see SUFG's previous forecast documents.)

The message of Figure 1-4 is clear and unequivocal. After a period of elevated prices caused by over building, prices have been declining due to more effective regulation. As a result, regulation has been kinder to Indiana rate payers. Further, SUFG expects a continued slight decline in electricity prices if the current regulatory compact is continued.

Long-Run Electricity Price Projections if Regulation Was to Continue

In addition to forecasting the regulated price trajectory over the planning horizon, SUFG has also estimated the long-run cost of electricity. The long-run price of electricity includes a fair return on generation investment, the cost of fuel, operation and maintenance (O&M) costs and charges associated with maintaining and operating the transmission and distribution (T&D) systems. The long-run cost of generation under continued regulation, a mix of the cost of generating electricity from combustion turbines (CT), natural gas-fired combined cycle (CC) and pulverized coal-fired (PC) plants, is forecast to be 3.93 cents per kWh and the long-run cost of T&D is forecast to be 1.09 cents per kWh. This results in a projected long-run electricity price of 5.02 cents per kWh.

The Forecast Impact of Deregulation on Indiana Rate Payers If Markets "Work"

Figure 1-5 shows SUFG's forecast of the likely trajectory of retail electricity prices, if, in 1999, Indiana, along with all the other Midwest states in the East Central Area Reliability Coordination Agreement (ECAR) and Mid-American Interconnected Network (MAIN) reliability regions, allowed hourly generation prices to be set by a Midwest power exchange or any other market mechanism that results in markets clearing at marginal costs. The forecast is based on two different scenarios:

- Scenario A: ECAR/MAIN exports to other parts of the U.S. will be 376 MW as described in the North American Electric Reliability Council (NERC) 1998 summer assessment.[5]
- Scenario B: Exports will be substantially larger -- 5500 MW.

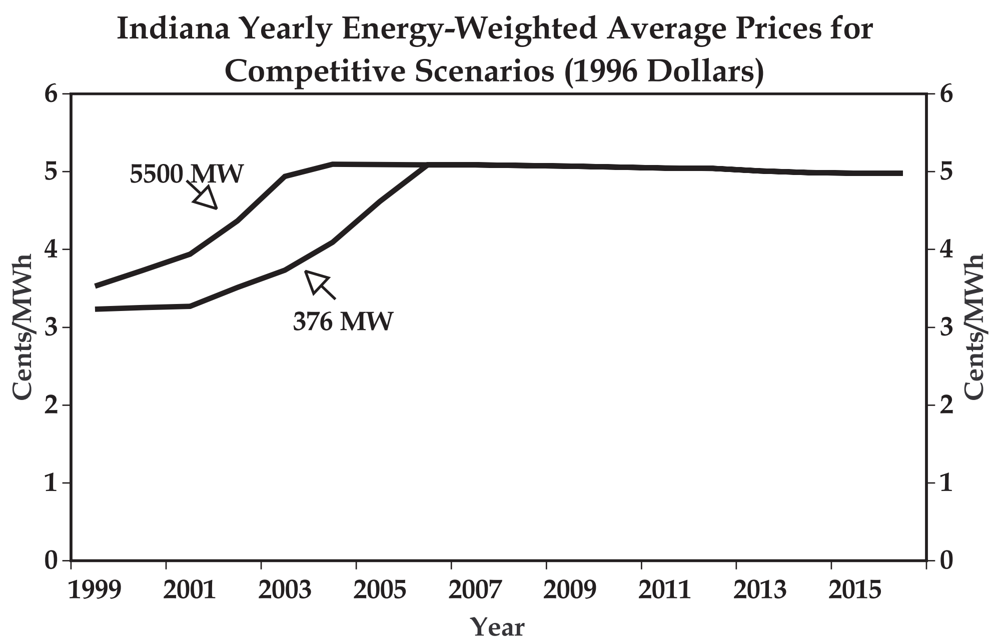
The general pattern of the price trajectories follows those contained in previous SUFG competitive price forecasts -- an initial drop, followed by a gradual increase until the price reaches the long-run price of new capacity if competition prevails.

From the electricity consumers' viewpoint, these trajectories represent an optimistic forecast: prices are not likely to be lower than these trajectories and to the extent that electricity prices will reflect their scarcity value, not their marginal cost, could be higher. The actual increase will depend on the market power of the sellers, and more importantly, the ability of buyers to reduce the avoided costs of purchasing in competitive markets.

The 1999 competitive model is substantially improved over SUFG's earlier versions. The first version was used in SUFG's 1996 forecast and the second version was presented in the May 1998 interim report.

[5]North American Electric Reliability Council, *1998 Summer Assessment*.

FIGURE 1-5



These model enhancements and the subsequent increase in forecast reliability are due to two factors:

- A better understanding of the structure of the emerging competitive power industry as more states move to allow such competition and
- a developing consensus regarding the elements that should be present in any model of price determination in such an industry.

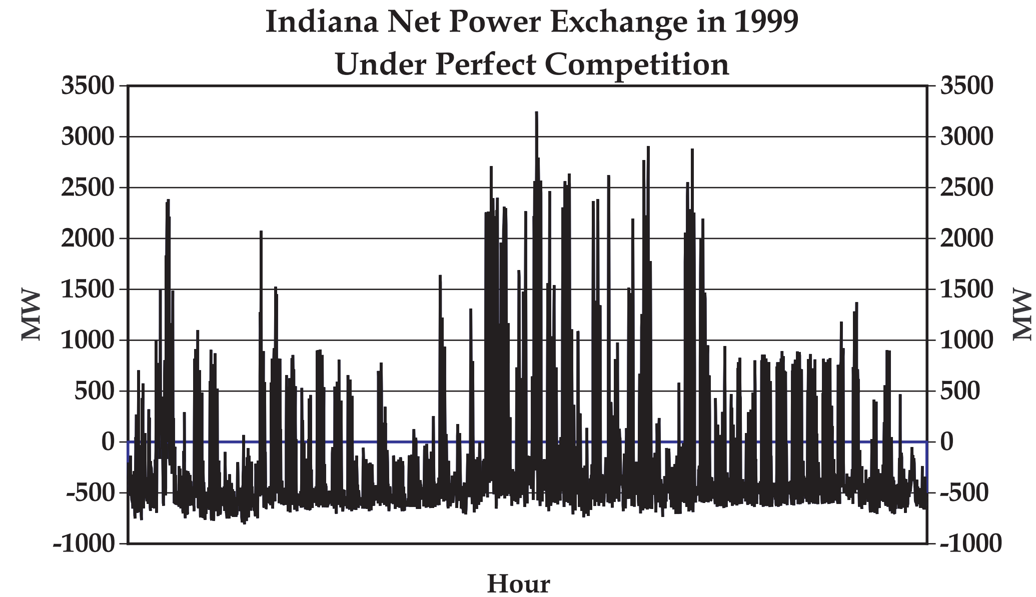
These two factors, both of which will tend to reduce forecast error, are partially offset by a deterioration in the data bases supporting such models, as utilities are increasingly unwilling to share reliable cost data which, they fear, may be used against them as former partners become competitors.

While maintaining the improved features of the 1998 model (power flow constraints, network congestion, hourly market clearing prices), the 1999 model has the capability of choosing the level of Indiana imports/exports that are consistent with a "free trade" scenario for an ECAR/MAIN trading area. The 1998 model determined the levels of Indiana exports outside the model.

Once the cost-minimizing patterns of trade (subject to the transmission constraints) are established within ECAR/MAIN, the resultant hourly pattern of imports and exports to and from Indiana can be calculated (see Figure 1-6). In addition, the hourly pattern of market clearing prices Indiana rate payers can expect to be charged for generation services can be determined.

Several important observations need to be made regarding Figure 1-6, which shows the net power exported from Indiana in 1999 resulting from the model. First, Indiana both exports *and* imports power. Although it is not obvious from the figure, exports take place during ECAR/MAIN peak demand periods while imports take place during off-peak periods.

FIGURE 1-6



Thus, what the model tells the analyst is that during off-peak (night, off-peak day use) hours, it is cheaper for Indiana utilities to import power from other regions since the avoided cost of Indiana generators during such periods is greater than the marginal cost of imported electricity.

Exactly the opposite is true during peak demand periods. At these times in the ECAR/MAIN system, it appears that the marginal costs of additional generation within Indiana falls below the avoided cost of utilities outside Indiana. This triggers a substitution of lower cost Indiana electricity for their higher cost "home grown" generation and results in the export "spikes" shown in Figure 1-6.

If the hourly sum over the year of all imports and exports shown in Figure 1-6 were calculated, Indiana would import an average of 150 MW per hour over the year 1999. That number decreases over the forecast horizon. This means that Indiana will become a net exporter in years later than 1999.

This result directly contradicts the assumption of a constant export demand for Indiana power made in the 1998 interim report, again emphasizing the extraordinary amount of uncertainty surrounding any forecasts of market behavior with deregulation.

SUFG's 1999 analysis suggests that this will not be the case; rather, Indiana will both import and export power depending on the time of day.

This result is certainly good news for Indiana stockholders since the value of their "export crop" — peak power — is certainly greater than any revenues lost due to the import of cheap off-peak power. The impact of all this on Indiana ratepayers is reflected only in the price they were expected to pay for electricity.

Long-Run Forecasts

This year's estimate of the long-run price of electricity if generation were opened up to competition is 4.99 cents/kWh. Previous SUFG estimates were 4.84 cents/kWh and 4.36 cents/kWh made in 1996 and 1998, respectively.

All three estimates employ the same methodology:

- Develop estimates of the long-run cost of generation from each of three types of units — combustion, turbines, combined cycle, and pulverized coal plants.
- Weigh each of these costs by their expected share of kWh generation and sum;
- Add the forecast cost of the still-regulated transmission/distribution system.

The changes in the forecast are mainly attributable to two factors:

- Upward revisions in the projected capital costs for the equipment. At the time of the 1996 and 1998 forecasts, few plants were on the drawing board; hence, estimates of capital costs were not precise. To remedy this, SUFG commissioned a study by a consulting company, SEPRIL, to estimate the likely construction costs for the three plant types. The 1999 estimate uses these costs rather than the earlier estimates.
- Downward revisions in the fuel cost, as a combination of improved heat rates and constant, or reduced forecasts of fuel prices decreased this component.

What If Competition Does Not Work Effectively?

SUFG's forecasts in the previous section assuming a competitive generation market were all based on the assumption that competition *works*. In this scenario, markets in economist's jargon are *perfect* -- no single buyer or seller can influence the price and all consider themselves as price takers rather than price makers. In that situation, all sellers bid a price equal to the marginal cost of all their available power, withholding none from the marketplace. As a result, prices generally equal marginal costs.

But, what if competition does not work effectively? Suppose producers or consumers *can* exert power over the market in such a way that market clearing prices are influenced. When this occurs, the industry departs from a perfectly competitive market structure and becomes imperfect. This is especially true when only a few large producers dominate the market. This raises the possibility that producers will create an artificial scarcity of electricity that drive prices well above marginal costs. This concept, frequently termed market gaming, results in imperfect competition.[6] Since this scenario is possible, it is important that models exist that can accurately quantify market power and its impact on prices.

Examples of real world departures of electricity prices from marginal cost abound. The difficulty comes from separating those caused by the correct functioning of markets from those caused by shortages that are artificially induced by dominant suppliers withholding production capacity.

Figure 1-7 is a plot of average prices paid for electricity hour by hour during August 1998 by members of the Pennsylvania-Jersey-Maryland Power Pool (PJM) power exchange and statistical estimates of the average marginal cost to produce this electricity -- again, hour by hour.

Figure 1-7 also shows that the relationship between market price and marginal cost depends on the time of day. During off-peak hours, when there are many generating units bidding for demands, market prices may be competitive and reflect marginal costs. However, during peak periods, when only a few units are available for additional production, prices will very likely depart from marginal costs as demanders

[6]Walter Nicholson, *Microeconomic Theory -- Basic Principles and Extensions,* 5th edition, The Dryden Press, 1998.

scramble to outbid each other for the scarce remaining supply.

A Comparison of Projected Regulation and Restructured Price Trajectories

Figure 1-8 shows SUFG's 1999 estimates of the likely price trajectory over the forecast horizon:

a. if the current rate base method of regulation were to remain in place; and

b. if, in 1999, Midwest generation markets were opened up to competition with trade as previous described in Scenarios A and B.

•Scenario A: ECAR/MAIN exports were as reported in the NERC 1998 summer assessment study.

•Scenario B: ECAR/MAIN exports were larger.

The forecast can be broken into three periods of interest: the short run, approximately the first five years; the intermediate run, the next 10 years and the long run, following that.

The Short Run

As in previous forecasts in the event of deregulation, SUFG would expect prices to immediately fall to levels well below those predicted if regulation were to continue under both scenarios.

As explained in other sections, these are the prices SUFG would predict if an ECAR/MAIN hourly power exchange (or other market mechanism free of excess buyer or seller power) were to be established. In such a market, a third party would set hourly market clearing prices that equate buyer bids with seller offers to assure that the lowest cost combination of generating units are dispatched to meet the demand for electricity at any point, taking into account the power flow

FIGURE 1-7

PJM Data: Energy-Weighted Average Market Clearing Price and Marginal Cost

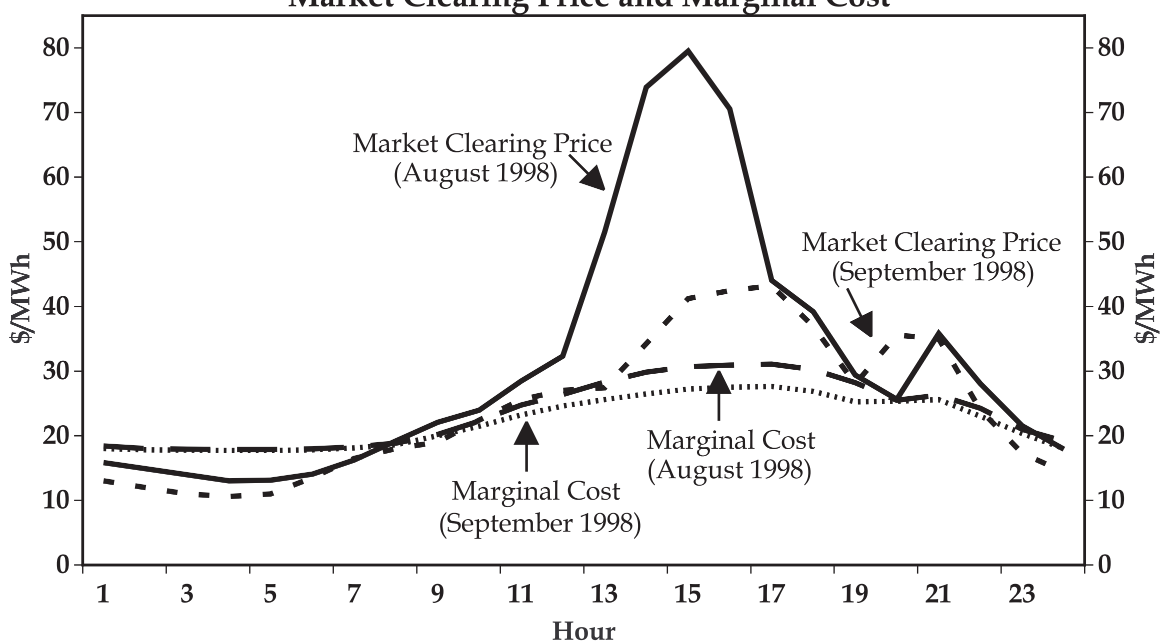
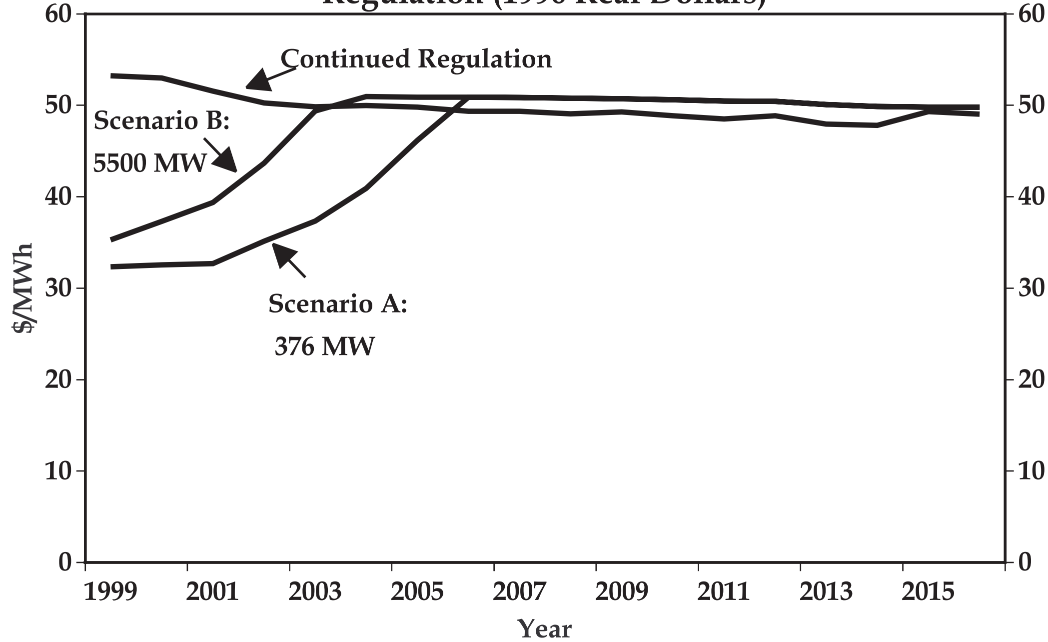


FIGURE 1-8

Indiana Yearly Energy-Weighted Average Prices -- Competition vs. Regulation (1996 Real Dollars)



and transmission capacity constraints, as well as line losses.

It should be emphasized that the assumption of a market mechanism *free of excess buyer or seller power* is crucial. Last summer's experience, when Midwest wholesale prices climbed to $7.50/kWh, a price clearly unrelated to any known marginal cost, casts doubt on the assumptions of perfectly competitive markets. SUFG, along with many other groups, is developing a method of incorporating elements of imperfect markets into the SUFG modeling system, the elements of which are reported elsewhere in this forecast.

This is not to say that the marginal cost pricing assumption is not useful; it is useful, not only in its own right as a forecast of what will happen, but also as a barometer of how well markets are working in the region. If observed prices over a long period of time depart from these levels, it could signal that markets are not functioning properly.

It is instructive to understand, in general terms, why prices are predicted to decrease below their regulated levels if a free market in generation develops in the ECAR/MAIN region. Under regulation, utilities are allowed to recover their fixed costs in addition to their variable cost through an average fixed cost per kWh "adder." This adder ensures that investors earn a fair return after tax on the remaining undepreciated investment in plant and equipment. In a marginal cost pricing scenario, the utility's return is the difference between the marginal cost of the most expensive unit dispatched to meet demand (the market price) and its own variable cost. This return may be greater than the average cost adder, as would be the case if the plant was close to fully depreciated and the market clearing price was very high during peak demand periods. It can also be less than the average cost adder if the plant is undepreciated and market clearing prices are low. Since, in Figure 1-8, prices set competitively are initially below those under continued regulation, the average cost adder Indiana investors would receive under regulation is greater than the adder set by the competitive market price.

The Intermediate Run

Upwards pressure on competitive prices caused by increased demands within the ECAR/MAIN trading area are forecast to eventually push prices up above their regulated levels -- earlier (2004) if the high ECAR/MAIN export scenario is assumed or later (2006) if the low ECAR/MAIN export scenario is assumed.

This repeats the same general pattern of regulated/competitive price behavior predicted in 1996 and 1998. As demand levels increase over time, competitive prices are expected to rise above those which would prevail if regulation were to continue. Again, while the detailed reasons for this are quite complex, the general reasons are fairly easy to understand.

The competitive market price for generation is capped by the long-run price of electricity. The instant the price is reached, all electricity, be it generated from old or new plants, sells at that market clearing price.

This, however, is not the case for the continued regulation scenario. The intermediate-term regulated price is slightly below the long-run regulated price because of an abundance of older, depreciated generation equipment. This older equipment has a small adder, which results in a lower price than is expected under the competitive scenarios. This lower price represents "stranded benefits" rather than stranded costs. As the older equipment is retired, the regulated price will rise to the long-run price.

As Figure 1-8 shows, the crossover point for the high ECAR/MAIN export scenario is forecast to take place about two years earlier than the low export scenario.

The Long Run

Finally, a comparison of the long-run price expected if regulation were to continue, 5.02 cents/kWh, and the long-run price of electricity if competition were allowed, 4.99 cents/kWh, apparently shows little difference. This is a bit misleading since the result is due to two opposite influences cancelling each other out in the final analysis.

- The tendency for competition creating incentives to drive down equipment and operating costs.
- The increased risk associated with investing in an industry now unprotected from competition and the corresponding increase in the cost of capital for the industry.

OVERVIEW OF SUFG ELECTRICITY MODELING SYSTEMS

Regulated Modeling System

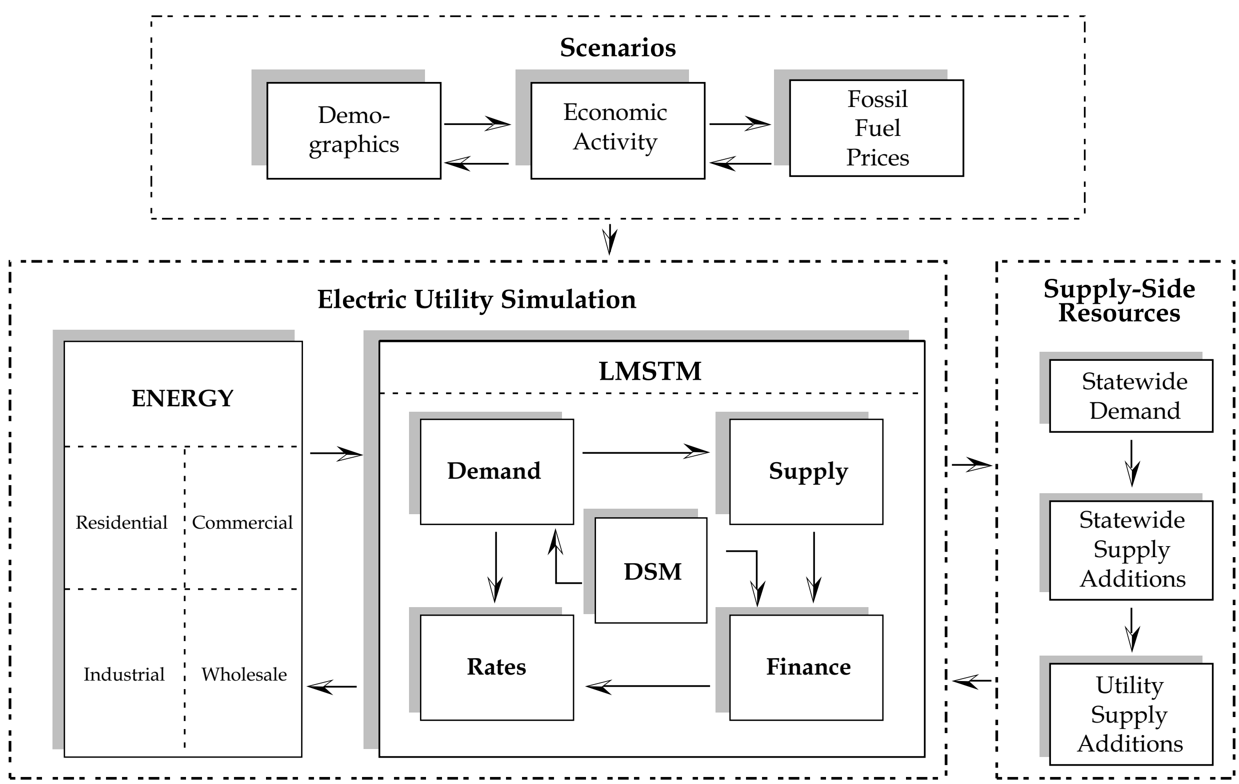
SUFG's integrated electricity modeling system projects electricity demand, supply and price for each electric utility in the state assuming continued regulation. The modeling system captures the dynamic interactions between customer demand, the utility's operating and investment decisions, and customer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

Energy Submodel

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

FIGURE 2-1

SUFG's Regulated Modeling System



Load Management Strategy Testing Submodel

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

LMSTM is used to model the five investor-owned utilities (IOUs): Indiana Michigan Power Company (I&M), a subsidiary of American Electric Power (AEP); Indianapolis Power & Light Company (IPL); Northern Indiana Public Service Company (NIPSCO); PSI Energy, Inc. (PSI Energy), a subsidiary of CINergy; and Southern Indiana Gas & Electric Company (SIGECO). In addition, LMSTM is used for the three not-for-profit (NFP) utilities: Hoosier Energy Rural Electric Cooperative, Inc. (HEREC); Indiana Municipal Power Agency (IMPA) and Wabash Valley Power Association (WVPA). Forecasts for unaffiliated rural electric membership cooperatives (UREMCs) and unaffiliated municipalities (UMUNYs) are derived from the forecasts for the five IOUs.

Price Iteration

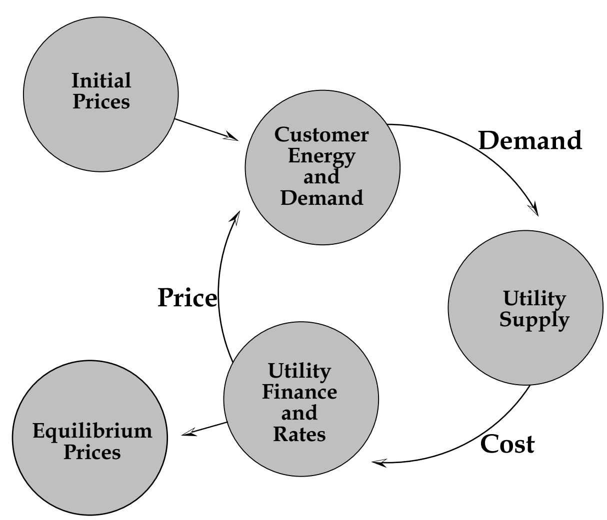
The energy modeling system cycles through the five integrated submodels just described: energy, demand, supply, finance and rates. During each cycle, price changes in the model cause customers to adjust their consumption of electricity, which in turn affects system demand, which in turn affects the utility's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

Uncertainty

As stated previously, SUFG's electricity projections are conditional on assumptions, or exogenous variables, such as economic growth, construction costs and fossil fuel prices. These assumptions are a principal source of uncertainty in any energy forecast. Another

FIGURE 2-2

Cost-Price-Demand Feedback Loop



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 were developed by operating the modeling system under varying sets of assumptions. These low probability, low and high scenarios capture much of the uncertainty associated with economic growth, fossil fuel prices and statistical error in the model structure.

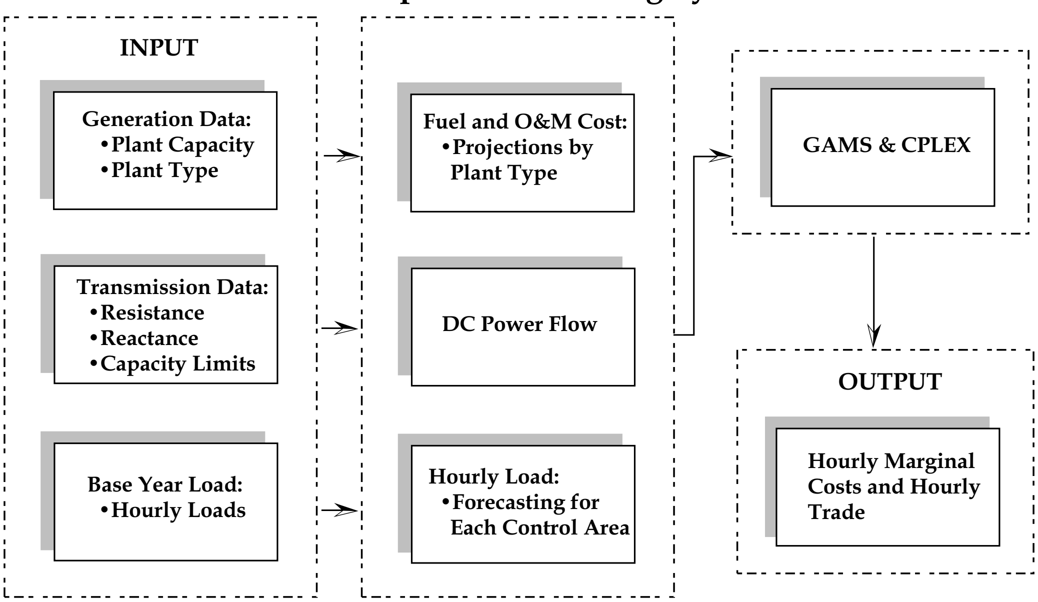
Competitive Modeling System

The SUFG competitive model simulates hourly optimal dispatch of generation for 32 utilities in the combined East Central Area Reliability Coordination Agreement (ECAR) and Mid-America Interconnected Network (MAIN) regions. Trade between utilities within the regions is determined hourly by relative marginal costs of generation, which are subject to the physical laws that determine power flows over a transmission system. These physical laws are approximated by a method commonly referred to as a DC approximation, or DC power flow and are included as constraints to the dispatch model. The level of trade between ECAR/MAIN and other regions is assumed exogenously in various scenario analyses.

Figure 2-3 illustrates the operation of the SUFG competitive model. The various input data, which are used to determine the marginal generation costs, power flow patterns and hourly demand for each control area, were obtained from federal sources and utilities. The General Algebraic Matrix System (GAMS) and CPLEX are commercial software packages that are used to determine the solution of the model. See Chapter 9

FIGURE 2-3

SUFG's Competitive Modeling System



and Appendix G for further details of the SUFG competitive model.

Chronology

This is the seventh forecast SUFG has prepared. Previous forecasts were published in 1987, 1988, 1990, 1993, 1995 and 1996. The 1996 forecast introduced the first version of SUFG's competitive model. In addition to these statewide forecasts, SUFG prepared forecasts of Indiana utility service area growth for the Indiana Utility Regulatory Commission's (IURC) use in three Certificate of Need cases. Tables 2-1 thru 2-5 present the chronology of enhancements and extensions of the SUFG electricity modeling system. Table 2-6 provides a list of software acronyms, along with a brief description of each.

TABLE 2-1

Chronology of Regulated Modeling Enhancements

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

TABLE 2-2

Chronology of Competitive Modeling Enhancements

1995	• Regional Forecasting Model Under Development
1996	• Two-Region Electricity Trade Model
1997	• Indiana State Dispatch Model
1998	• ECAR/MAIN Dispatch Model

TABLE 2-4

Chronology of Demand-Side Management Enhancements

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

TABLE 2-3

Chronology of Supply, Finance and Rates Enhancements

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

TABLE 2-5

Chronology of Model Applications

1987	•SUFG 1987 Forecast
1988	•SUFG 1988 Forecast •SUFG Acid Rain Studies
1989	•Indiana State Agency Workgroup Acid Rain Studies
1990	•SUFG 1990 Forecast •ISAW Acid Rain Studies
1991	•PSI Energy Certificate of Need Combustion Turbine (CT)
1992	•IPL Certificate of Need (CT) •PSI Energy Certificate of Need (Destec)
1993	•SUFG 1993 Forecast
1994	•SUFG 1994 Forecast •Quarterly Updates (4) of 1993
1996	•SUFG 1996 Forecast
1998	•SUFG's Interim Report on Competitive Restructuring
1999	•SUFG 1999 Forecast

TABLE 2-6		
Acronyms and Definitions		
CEDMS	–	Commercial Energy Demand Modeling System. Off-shoot of TVA end-use model, supported and enhanced by Jerry Jackson and Associates.
CPLEX	–	A mathematical optimizer for linear and integer programming problems.
DSIMPACT	–	A detailed DSM evaluation model developed for SUFG by Ed Frye to link SUFG's energy models to DSM program evaluation.
DSManager	–	Demand-Side Manager. An EPRI sponsored DSM screening model supported by Electric Power Software.
GAMS	–	General Algebraic Matrix System. This computer platform has higher order computer programming languages that are designed to interface with other mathematical solvers, such as CPLEX
HELM	–	Hourly Electric Load Model. Builds up end use (or more aggregate) load using 8760 hourly loads per year. Developed with EPRI sponsorship.
INDEPTH	–	Methodology for forecasting and shaping industrial electricity use at the service area level.
IRP-Manager	–	Integrated Resource Planning Manager. A detailed planning model which simultaneously evaluates DSM programs and supply-side resources under uncertainty. Developed and supported by Electric Power Software.
ISAW	–	Indiana State Agency Workgroup. An interagency workgroup which analyzed compliance strategies for several clean air proposals.
LMSTM	–	Load Management Strategy Testing Model. A detailed dispatch, finance, rates and environmental analysis model with explicit treatment of DSM. Supported by Electric Power Software.
REEMS	–	Residential Electric End-Use Energy Modeling System. Off-shoot of TVA end-use model, originally supported by Dennis O'Neal of Texas A&M.
TEEMS	–	Technology-Based End-Use Energy Modeling System jointly developed by SUFG and EPS. TEEMS integrates the functions of end-use forecasting and DSM resource forecasting into a single modeling framework with a common database.
TELPLAN	–	Total Electric Planning Model. This model includes dispatch, finance and environmental analysis capabilities. EPRI sponsored in early 1980s.

CHAPTER 3

MAJOR FORECAST INPUTS AND ASSUMPTIONS FOR THE REGULATED MODELING SYSTEM

Introduction

The models SUFG utilizes to project electric energy sales, peak demand and prices require external, or exogenous assumptions for several key inputs. These input assumptions pertain to the level of economic activity, population growth and age composition for Indiana. Fossil fuel prices, which are used to generate electricity and compete with electricity to provide end-use service, are also included.

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 economic activity determine, to a large degree, the essence of SUFG's forecasts. These macroeconomic 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).

- 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.

Demographic Projections

Household projections are a major input to the residential energy forecasting model. The SUFG forecasting system includes a housing model which utilizes population and income assumptions to project households. The housing model is described in Appendix A.

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

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

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

The historical growth of household formations (number of residential customers) has slowed down significantly from slightly over 2 percent during the late 1960s and early 1970s to slightly less than 1 percent currently. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of 0.66 percent over the forecast period. This is virtually identical to the 0.63 rate projected in SUFG's 1996 forecast. The household projection growth rate decreases slightly to 0.65 percent in the low scenario and increases slightly to 0.69 percent in the high scenario. The growth rates across scenarios are similar because the same population projections are used for each scenario and CEMR's income projections do not vary greatly across scenarios.

Economic Activity Projections

National and state economic projections are produced by the CEMR twice each year. For this forecast, SUFG adopted CEMR's February 1998 economic projections as its current base scenario. CEMR also produced high and low growth alternatives to the base projection for SUFG's use in its high and low scenarios.

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

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

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 19 manufacturing and 11 non-manufacturing sectors. The second module then projects the share of each industry in Indiana. Additional relationships are used to project average weekly hours and average hourly earnings by industry. These are used with employment to calculate a total wage bill. The third module projects the remaining components of personal income. In the fourth module, labor productivity combined with employment projections is used to calculate real Gross State Product (GSP), or output, by industry. A more detailed description of the Indiana model is also contained in Appendix F.

The main exogenous assumptions in the national projections used in the February 1998 CEMR forecast are as follows:

- The Federal Reserve Bank will maintain the long-run growth rate of the money supply (M2) at 6 to 8 percent. This will cause a gradual increase in short-term interest rates.
- Federal tax rates will be relatively stable and federal purchases will increase slightly. As a result, the federal budget maintains a modest surplus through the end of the forecast horizon.

- Imports continue to exceed exports (measured in dollars), which leads to a continued negative net trade balance.
- Oil prices will rise at an increasing rate starting at about 1 percent per year and rising to over 2 percent per year at the end of 2015.

As a result of these assumptions, real Gross Domestic Product (GDP) for the U.S. economy is projected to grow at an average annual rate of 2.66 percent and U.S. employment growth averages 1.21 percent over the 1996 to 2016 period.

In Indiana, total employment is projected to grow at an average annual rate of 1.00 percent. The key economic projections are:

- Real personal income (the residential sector model driver) is expected to grow at a 1.85 percent annual rate.
- Non-manufacturing employment (the commercial sector model driver) is expected to average a 1.47 percent annual growth rate over the forecast horizon.
- Despite the continued decline of manufacturing employment, manufacturing GSP (the industrial sector model driver) is expected to rise at a 1.61 percent annual rate as gains in productivity offset declines in employment.

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 3-1.

To capture some of the uncertainty in energy forecasting, SUFG requested CEMR to produce 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 average growth rate of personal income is increased by about 0.6 percent per year (to 2.42), non-manufacturing employment growth increases more than 1.0 percent (to 2.56), while real manufacturing GSP growth is raised about 0.7 percent (to 2.28). In the low growth alternative, the average rates of growth of real personal income, non-manufacturing employment and real GSP are reduced by similar amounts (to 1.62, 1.26 and 0.42 respectively).

Sales to Indiana's industrial sector account for over 45 percent of total Indiana electricity sales. Two industries — *primary metals* (i.e., steelmaking, aluminum, foundries) and *transportation equipment* (i.e., motor vehicles, parts) — account for one-third of total industrial sales. These forecasts are described in Chapter 7, which discusses energy sales to the industrial sector. The two major forecast assumptions for these industries pertain to new or upgraded facilities and increases in self-generation. Because of their importance, forecasts for output and electricity sales have been made by the SUFG staff for these industries to replace those provided by CEMR and SUFG's econometric modeling system.

Fossil Fuel Price Projections

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

TABLE 3-1

Growth Rates for Current and Past CEMR Projections of Selected Economic Activity Measures (%)

	Short-Run History for Selected Recent Periods			Long-Run Forecast Aug. 1994	Feb. 1998
	1980-1985	1985-1990	1990-1996	1994-2014	1996-2016
United States					
Real Personal Income	3.02	2.59	2.16	2.75	2.61
Total Employment	1.53	2.00	1.48	1.26	1.21
Real Gross Domestic Product	2.53	2.73	1.95	2.28	2.66
Personal Consumer Expenditure Deflator	5.33	4.15	2.93	3.47	2.50
Indiana					
Real Personal Income	1.13	2.10	2.54	1.73	1.85
Employment:					
Total	0.21	2.76	1.65	0.99	1.00
Manufacturing	-1.48	0.91	0.91	-0.53	-0.60
Non-Manufacturing	1.17	3.70	2.20	1.47	1.47
Real Gross State Product					
Total	1.61	2.73	3.64	1.75	1.76
Manufacturing	1.92	2.82	5.56	2.22	1.61
Non-Manufacturing	1.47	2.69	2.77	1.49	1.83

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

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, as described in Chapter 2 and Appendices A through F, is designed to simulate each of these effects as well as the dynamic interactions among all effects.

In this forecast, SUFG has utilized December 1997 fossil fuel price projections from the Energy Information Administration (EIA) for the East North Central Region of the U.S. All SUFG projections are in terms of real prices (1996 dollars), i.e., projections with the effects of inflation removed. The general patterns of the fossil fuel price projections are that:

- Coal prices will decline in real terms throughout the entire forecast horizon.
- Gas price projections for electric utilities and industrial customers stop decreasing after the year 2000 with moderate increases for electric utilities and a slight increase for industrial customers through the remainder of the forecast horizon. For

residential and commercial customers, gas price projections exhibit a modest decline over the forecast horizon.

- Oil and distillate prices will remain constant until the turn of the century then increase over the remainder of the forecast horizon.

The pattern of fossil fuel price projections is presented as growth rates in Table 3-2 for the near term (1996-2000) and long term (2000-2016). In the 1996 forecast, SUFG employed Data Resources Inc. (DRI) projections. The growth rates for these projections are included for comparison.

Forecast Uncertainty

There are three sources of uncertainty in any energy forecast:

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

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

Stochastic error is inherent in the structure of any forecasting model. Sampling error is one source of stochastic error. Each set of observations (the historical data) from which the model is estimated constitutes a sample. When one considers stochastic model error, it is implicitly assumed that the model is correctly specified and that it is using correctly measured data. Under these assumptions the error between the estimated model and the true model (which is always unknown) has certain properties. The expected value of the error term is equal to zero. However, for any observation in the sample, it may be positive or nega-

TABLE 3-2

Growth Rates for Real Fossil Fuel Price Projections (%)

	1996-2000	2000-2016	1996-2016	DRI 1995 Projections* (1994-2014)
Coal				
Electric Utilities	-1.69	-0.94	-1.07	-1.96
Industrial Customers	-1.15	-0.52	-0.65	-1.24
Natural Gas				
Electric Utilities	-3.40	3.60	2.16	0.75
Residential Customers	-2.47	-0.26	-0.71	-0.21
Commercial Customers	-2.60	-0.16	-0.65	-0.13
Industrial Customers	-2.56	0.57	-0.07	-0.18
Oil & Distillate				
Electric Utilities	-1.54	0.86	0.37	2.11
Residential Customers	-1.29	0.64	0.25	0.66
Commercial Customers	-2.09	0.84	0.25	1.15
Industrial Customers	0.60	1.10	1.00	1.79

* Used in SUFG's 1996 forecast projections.

Source: EIA Annual Energy Outlook, 1998 DOE/EIA-0383(98), December 1997 Supplementa Data, Part B.

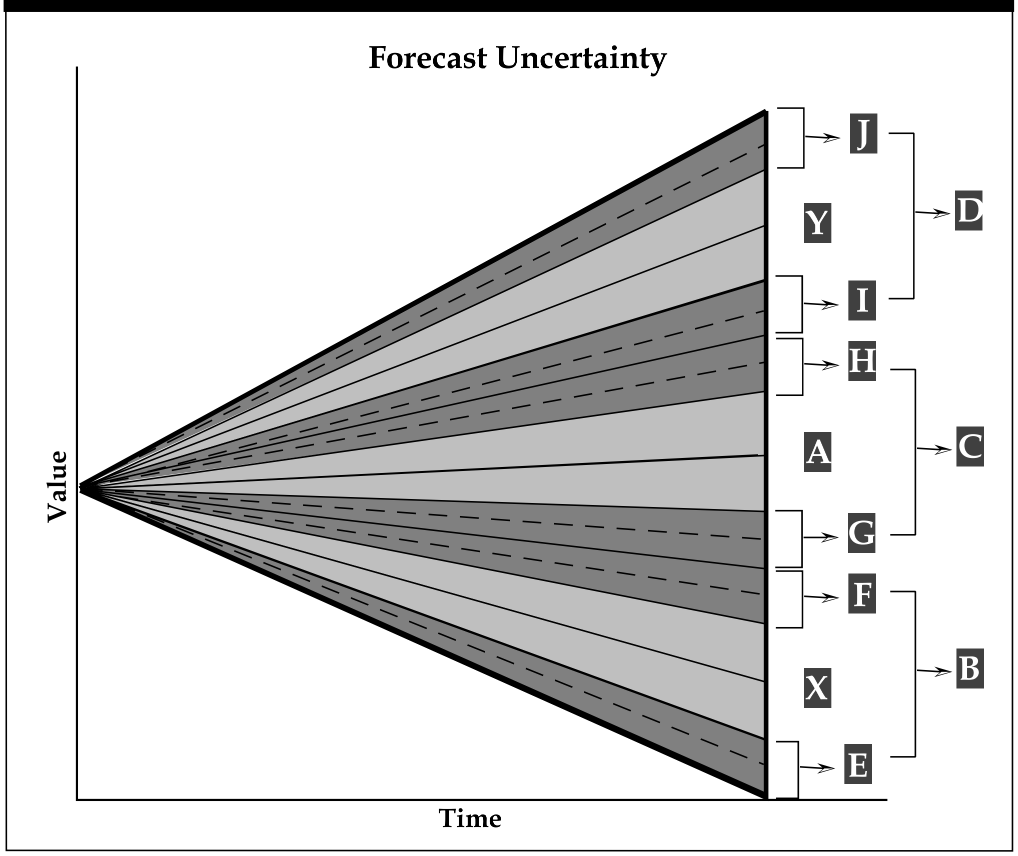
tive. The errors from a number of samples follow a pattern, which is described as the normal probability distribution, or bell curve. This particular normal distribution has a zero mean, and an unknown, but estimable variance. The magnitude of stochastic model error is directly related to the magnitude of the estimated variance of this distribution. The greater the variance is, the larger the error will be.

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

The uncertainty inherent in any energy forecast is illustrated in Figure 3-1. In this figure, *A* denotes the most likely trajectory of any forecast. The trajectories which denote the extreme low and high exogenous assumptions are X and Y, respectively. The range of stochastic model error surrounding the three trajectories are defined by B, C and D. The range of non-stochastic model error are defined by E, F, G, H, I and J.

In Figure 3-1 each set of exogenous assumptions, A, X and Y, defines a scenario and a possible future trajectory with an associated probability of occurrence. Some scenarios are more likely than others. This expected, or "most likely," future trajectory is defined to have an equal probability of being too low or too high. It is the most important point on the forecast distribution curve simply because it is the most probable.

FIGURE 3-1



In this figure, trajectory A denotes the "most likely" trajectory. This corresponds to SUFG's base scenario. However, trajectory A assumes that the forecasting model and all its inputs are known with perfect certainty. If it is assumed that the exogenous assumptions are known with perfect certainty and the model has stochastic error only, the most likely trajectory lies in the interval denoted by C. If we add non-stochastic error, the most likely forecast lies in the interval that extends from the lower limit of G to the upper limit of H.

By including all sources of uncertainty, the trajectory lies in the interval that extends from the lower limit of E to the upper limit of J. The complete forecast distribution curve includes all possible future trajectories, including all sources of uncertainty, and their associated probabilities.

While the three sources of uncertainty discussed above are important, another major source of uncertainty may be of more importance, and that is the changing structure of the electric utility industry. Over the past several years competitive pressures have begun to change the industry, especially in the marketing of bulk wholesale power. Current pressures appear to be directed toward increasing competition, especially in generation and transmission. The outcome of these pressures on the structure of the industry is extremely uncertain. Rather than attempt to quantify the affects of competitive pressures within a traditional regulation forecasting framework, SUFG has developed a model to analyze the impacts of competition. Those results are presented in Chapter 9.

CHAPTER 4
INDIANA PROJECTIONS OF ELECTRICITY REQUIREMENTS, PEAK DEMAND, RESOURCE NEEDS AND PRICES

Introduction

This report includes three scenarios of future electricity demand and supply: base, low and high. The statewide results for these scenarios are presented in this section of the report, along with their associated resource and equilibrium price implications.

The base scenario is developed from a set of exogenous assumptions that is considered "most likely," i.e., each assumption has an equal probability of being lower or higher. Additionally, SUFG developed low and high growth scenarios based on plausible sets of exogenous assumptions that have a lower probability of occurrence. These scenarios are designed to indicate a plausible forecast range, or degree of uncertainty underlying the base projection. The most probable projection is presented first.

Most Probable Forecast

As shown in Figures 4-1 and 4-2, SUFG's current base scenario projection indicates annual growth of electricity requirements and peak demand of 1.80 and 1.73 percent, respectively. Both are somewhat lower than SUFG's 1996 base projections. The shaded numbers in the tables and the heavy line in the graphs indicate historical values.

The reduction in the projection of electricity requirements, as shown in Table 4-1, can be traced to substantially lower growth in industrial sales, which is offset somewhat by increased residential and commercial sales. The decrease in industrial sales growth compared to the current forecast is partially attributable to SUFG's scenario-based methodology for forecasting electricity sales to the steel and automotive industries, and partially due to decreased industrial output growth as well as changes in the mix of industrial output growth for individual 2-digit Standard Industrial Classification (SIC) industries taken from the CEMR macroeconomic projection. For a complete discussion of the sectoral forecasting models and projections, see Chapters 5, 6 and 7.

The growth in peak demand is almost identical to that projected in 1996. This is despite some significant differences. The 1996 peak load projection included approximately 1400 MW of interruptible load and demand-side management (DSM). In contrast, SUFG's current peak load forecast includes only half of that amount of combined interruptible load and DSM.

Resource Implications

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

Demand-Side Resources

The current projection includes the energy and demand impacts of existing or planned utility-sponsored DSM programs (see Chapter 8 for a description of Indiana's DSM programs). DSM programs are projected to reduce peak demand by approximately 150 MW. This is the equivalent of one 150 MW peaking unit.

These DSM projections do not include the reductions in peak demand due to interruptible load contracts with large industrial customers. Approximately 540 MW of large industrial load is classified as interruptible in this forecast.

Supply-Side Resources

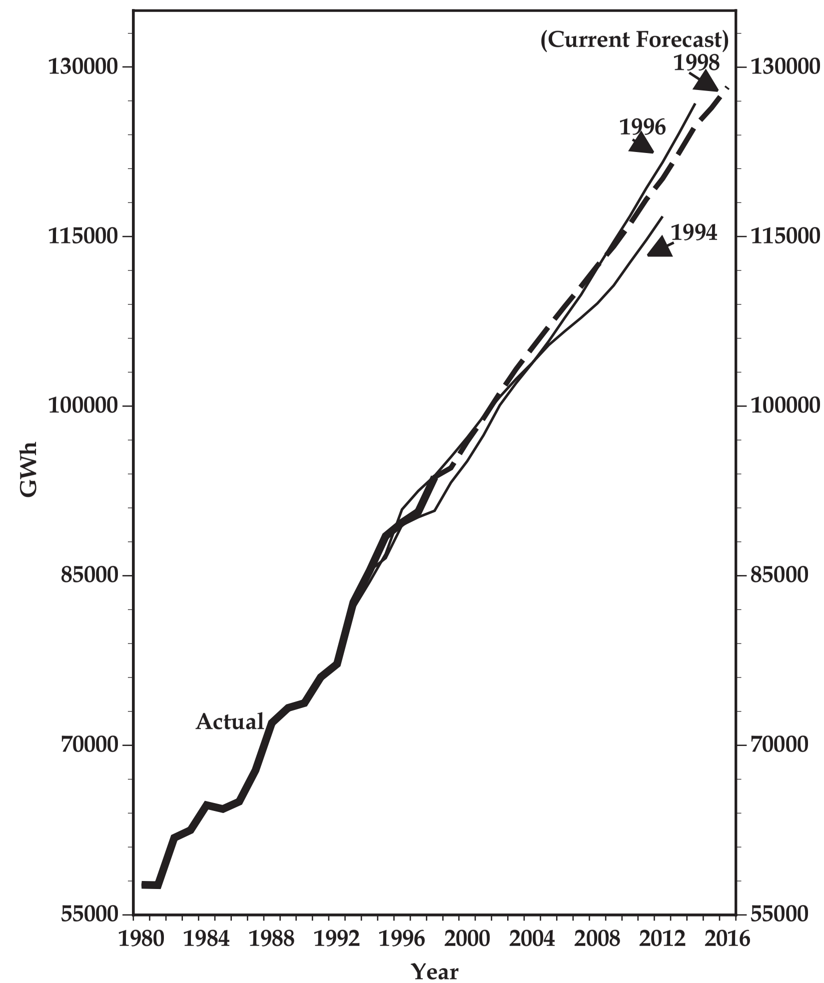
SUFG's base resource plan includes all currently planned capacity changes. Planned capacity changes include: certified, rate base eligible generation additions, retirements, deratings due to scrubber retrofits and net changes in firm out-of-state purchases and

FIGURE 4-1

Indiana Electricity Requirements in GWh (Historical, Current and Previous Forecasts)

Year	Year of Forecast 1994	1996	1999
1990	73742	73742	73742
1991	76034	76034	76034
1992	77207	77207	77207
1993	82084	82669	82669
1994	84482	85446	85446
1995	86930	86572	88514
1996	90877	89468	89698
1997	92507	90183	90662
1998	93841	90765	93729
1999	95515	93233	94561
2000	97226	95154	96867
2001	99091	97441	98922
2002	100820	100101	101170
2003	102420	102047	103298
2004	103850	103845	105179
2005	105420	105769	107058
2006	106620	107810	108833
2007	107830	109852	110601
2008	109090	112234	112433
2009	110690	114573	114148
2010	112720	116825	116124
2011	114690	119279	118291
2012	116800	121578	120130
2013		124137	122389
2014		126802	124797
2015			126406
2016			128237

Average Compound Growth Rates			
Forecast Period	1992-09	1994-14	1996-16
	2.09	1.99	1.80



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

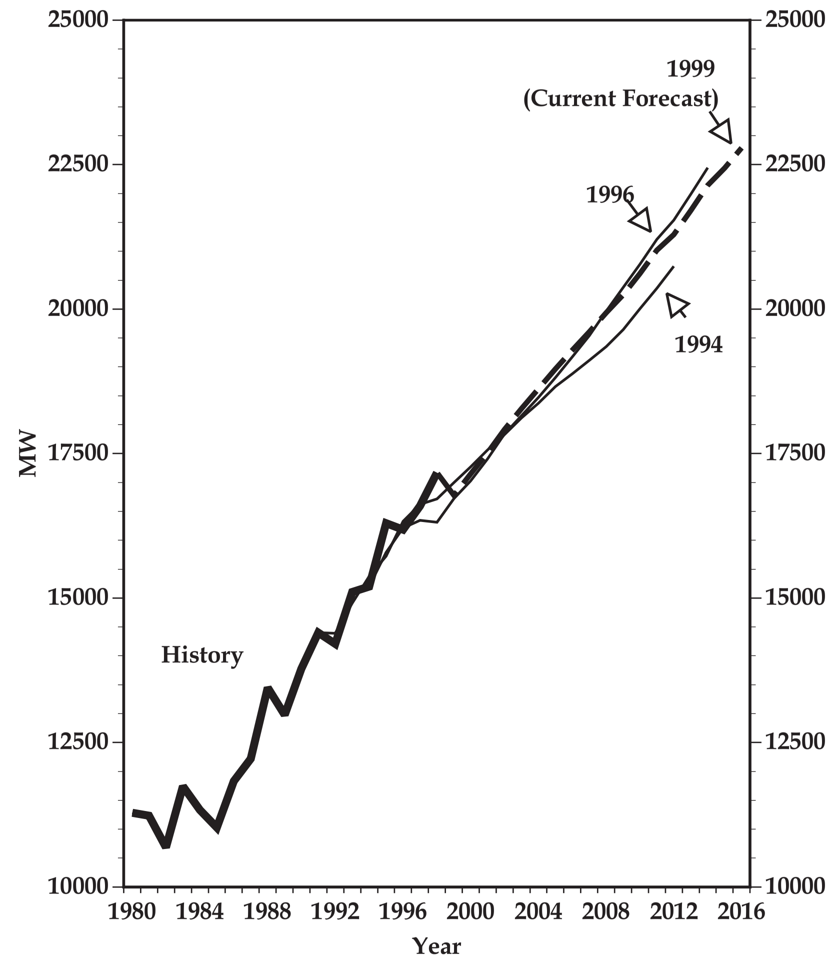
FIGURE 4-2

Indiana Demand Projections in MW
(Historical, Current and Previous Forecasts)

Year	Year of Forecast 1994	1996	1999
1990	13775	13775	13775
1991	14403	14403	14403
1992	14388	14209	14209
1993	14913	15103	15103
1994	15373	15199	185198
1995	15727	15789	16294
1996	16330	16212	16184
1997	16621	16342	16596
1998	13717	16311	17168
1999	16997	16720	16779
2000	17267	17026	17145
2001	17562	17407	17514
2002	17829	17837	17917
2003	18114	18158	18279
2004	18374	18473	18620
2005	18658	18812	18962
2006	18882	19177	19288
2007	19112	19539	19604
2008	19350	19965	19936
2009	19645	20377	20248
2010	20006	20773	20614
2011	20362	21204	21019
2012	20744	21541	21290
2013		21985	21703
2014		22447	22142
2015			22443
2016			22789

Average Compound Growth Rates

Forecast Period	1992-09	1994-14	1996-16
	1.85	1.97	1.73



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

TABLE 4-1

Annual Electricity Sales Growth (%) By Sector (Current vs. 1996 Projections)

Sector	Electricity Sales Growth	
	Current (1996-2016)	1996 (1994-2014)
Residential	1.67	1.46
Commercial	2.25	2.09
Industrial	1.53	2.31
Total	**1.80**	**1.99**

sales. SUFG does not attempt to forecast long-term out-of-state contracts other than those currently in place. Generic generating units are then added as necessary during the forecast period to maintain a statewide 15 percent reserve margin. The 15 percent reserve margin is a "rule-of-thumb" that reflects recent national average reserve margins. Due to diversity in demand between utilities, a statewide 15 percent reserve margin occurs when individual utility reserve margins are roughly 11 percent. The anticipated restructuring pressures have led utilities to plan based on lower reserve margins. In some instances, units have been added to maintain individual utility reserve margins at 6 percent, even if the state as a whole does not need new capacity.

Three types of generic generating unit resources are included:

1. 150 MW gas-fired combustion turbines;
2. 200 MW gas-fired combined cycle (CC) units; and
3. 500 MW scrubbed, pulverized coal-fired (PC) baseload units.

See Appendix E for a detailed description of the capacity addition methodology.

Figure 4-3 shows the statewide resource plan for the SUFG base scenario. Over the first half of the forecast period, 1750 MW of gas-fired capacity and 500 MW of new coal-fired capacity are added. The net change in generation includes the retirement of several units as reported in the utilities 1997 Integrated Resource Plan (IRP) filings. Over the second half of the forecast period, 2925 MW of additional gas-fired capacity is added, while 2500 MW of new coal-fired generation is acquired.

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.

SUFG's base scenario equilibrium real electricity price trajectory is shown in Figure 4-4. Declines in the real price of electricity during the first half of the forecast period are largely offset by increases during the second half of the forecast period. Since the change in prices over the forecast horizon is small, closing the loop has little impact on the electricity requirements' projection for this forecast. This price trajectory reflects the schedule of projected capacity additions in the base resource plan. Real prices decline through 2004 when low capital-investment resources are acquired to maintain a 15 percent reserve margin. Real prices level after 2004 as capital-intensive intermediate and baseload capacity is added to maintain adequate system reserves (see Figure 4-4). See Appendix E, Table E-1, for unit cost assumptions for generation additions.

SUFG's equilibrium price projections for two previous forecasts are also shown in Figure 4-4. The price projection labeled "1994" is the base case projection contained in SUFG's 1994 forecast report and the price projection labeled "1996 LCC" is the Lower Capital Cost (LCC) scenario from SUFG's 1996 report. For the

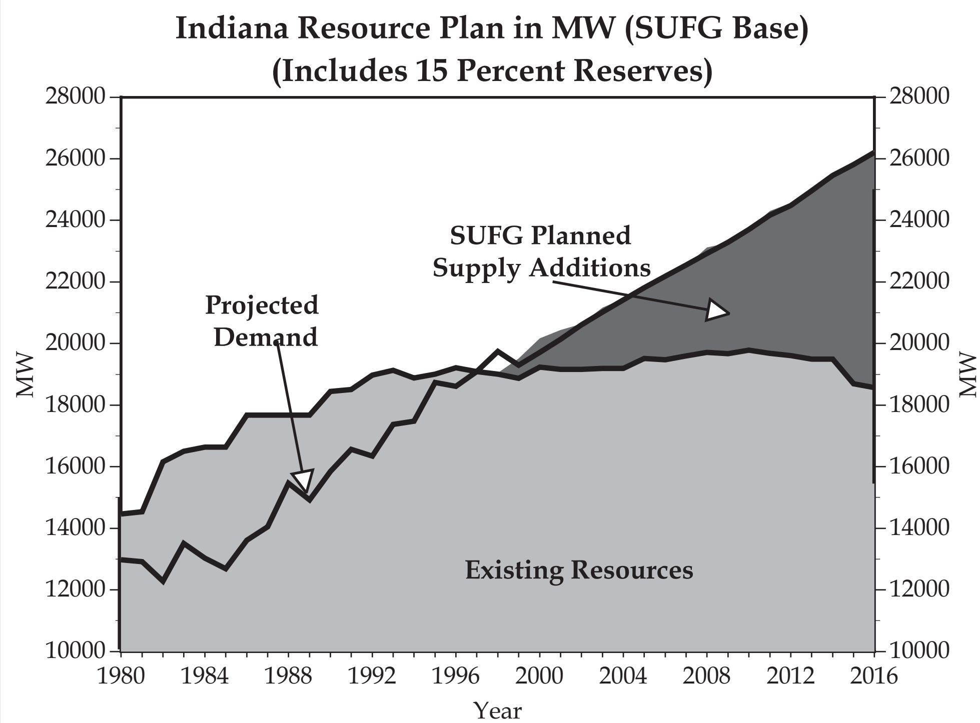
FIGURE 4-3

Indiana Resource Plan
(SUFG Base)

Year	Demand	Capacity*	Additions (in MW)			Retired	Reserve	Comments
			Peaking	Cycling	Base Load	Penalty	Margin (%)	
1996	16184	19216	0	143	27	0	18.7	PSI adds Wabash River Repowering Project; SIGECO upgrades Culley Unit 3
1997	16596	19084	0	0	0	0	15.0	
1998	17168	19050	0	0	45	0	11.0	I&M upgrades Cook Unit 2 (Nuclear)
1999	16779	19520	600	0	0	0	16.3	
2000	17145	20174	300	0	0	0	17.7	I&M long-term firm sale expires
2001	17514	20460	350	0	0	0	16.8	
2002	17917	20660	0	200	0	0	15.3	
2003	18279	21190	0	0	500	0	15.9	
2004	18620	21490	300	0	0	0	15.4	
2005	18962	21810	0	0	0	0	15.0	I&M long-term firm sale expires
2006	19288	22267	0	0	500	43	15.4	NIPSCO retires Mitchell gas turbines 9A-9C
2007	19604	22547	150	0	0	70	15.0	HEREC long-term firm sale expires; IPL retires Stout Units 3 and 4
2008	19936	23159	0	0	500	88	16.2	HEREC long-term firm sale expires; IPL retires Stout gas turbines 1-3; NIPSCO retires Bailly gas turbine 10
2009	20248	23295	0	175	0	39	15.0	IPL retires Pritchard Unit 1
2010	20614	23751	150	200	0	99	15.2	I&M long-term firm sale expires; IPL retires Pritchard Unit 2; NIPSCO retires Michigan City Unit 2
2011	21019	24323	0	175	500	103	15.7	IPL retires Pritchard Unit 3; NIPSCO retires Michigan City Unit 3
2012	21290	24583	125	200	0	0	15.5	
2013	21703	24940	275	200	0	118	14.9	IPL retires Pritchard Units 4 and 5
2014	22142	25565	125	0	500	0	15.5	
2015	22443	25812	375	675	0	804	15.0	I&M retires Tanners Creek Units 1-4
2016	22789	26287	100	0	500	125	15.3	

*Includes installed capacity plus firm purchases minus firm sales.
Source: SUFG Modeling System and Utility IRP filings for retirements.

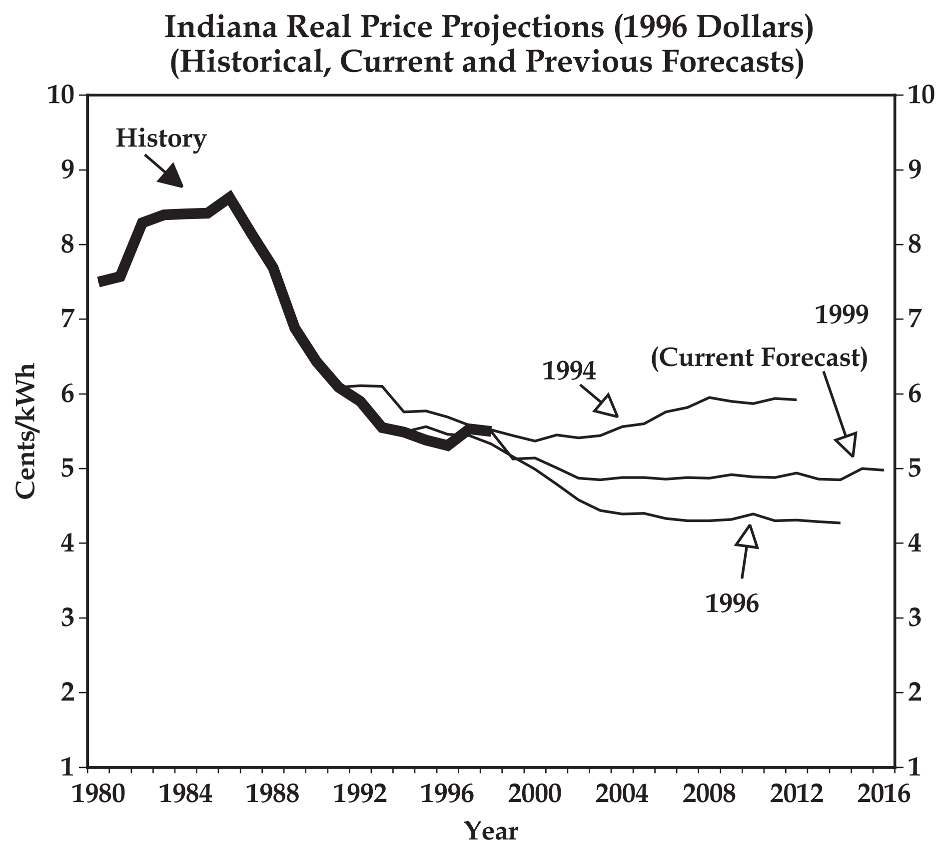
FIGURE 4-3 (Continued)



prior price forecasts, SUFG rescaled the original price projections to 1996 dollars (from 1992 dollars for the 1994 projection, and from 1994 dollars for the 1996 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

Two major factors primarily determine the differences among the price projections in Figure 4-4; namely, the capital cost assumptions for new generation equipment and the target reserve margin. The capital cost estimates directly impact projected electricity prices and the reserve margin assumption affects both the timing and magnitude of new generation capacity. In the 1994 forecast SUFG used generation equipment cost estimates from the 1991 Electric Power Research Institute (EPRI) Technical Assesment Guide (TAG) and assumed a 20 percent statewide reserve margin. The 1996 LCC scenario used capital costs which were one-half of those reported in the 1993 EPRI TAG and assumed a 15 precent statewide reserve margin. The current base case capital cost assumptions were developed by SEPRIL and are somewhat higher than those assumed in the 1996 LCC scenario and lower than those in the 1994 base case. The current base case also assumes a 15 percent reserve margin consistent with recent electric industry experience. The 1996 base case price projections are very similiar to the current projections (thus not shown in Figure 4-4) and used 1993 EPRI TAG cost estimates and a 20 percent reserve margin target. Other factors such as energy and demand growth as well as fossil fuel price assumptions also influence the tragectory of future prices, but these have been relatively unchanged during SUFG's recent forecasts. More detail reqarding the assumptions and procedures used in SUFG's 1994 and 1996 price forecasts may be found in previous SUFG reports.

FIGURE 4-4



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

Low and High Scenarios

SUFG has constructed alternative, low and high growth scenarios. These low probability scenarios are used to indicate the forecast range, or dispersion of possible future trajectories. Figures 4-5 and 4-6 provide the statewide electricity requirements and peak demand projections for the base, low and high scenarios. As shown in those figures, the annual growth rates for the low and high scenarios are about 0.35 percent lower and 0.65 percent higher than the base scenario for both energy requirements and peak demand. These differences are due to economic growth assumptions in the scenario-based projections.

Resource and Price Implications Of Low and High Scenarios

Resource plans are developed for the low and high scenarios in analogous fashion to the base plan. Demand-side resources, including interruptible loads, are the same in all three scenarios, as are retirements. Table 4-2 shows the statewide supply-side additions for each scenario. Approximately 11150 MW are acquired in the high scenario compared to only 5975 MW in the low scenario. By the end of the forecast period, electricity prices in the high case are 1 percent higher than in the base case. This is because 3475 MW of additional generating capacity are acquired relative to the base scenario. Prices in the low scenario are only about 1 percent lower than the base scenario despite significantly fewer resource additions. This is caused by the lack of sales growth, which in addition to delaying the need for resource additions, results in allocation of fixed costs of existing and future generation resources to fewer kWh.

Estimate of Long-Run Costs with Continued Regulation

The eventual need for new capacity will cause average and marginal costs to approach the long-run marginal cost of electricity. In all cases, this cost will be determined by the mix of generating units -- peak, cycle and base -- that minimize the long-run cost of meeting the daily and seasonal fluctuating demand for electricity.

SUFG obtained construction and operating costs, and heat rate information on new generation units from SEPRIL Services. The costs and heat rates associated with the three types of generators considered are provided in Table 4-3.

The average cost of energy generated by a new portfolio of generation plant units will be the average of the different unit types weighted by the amount of generation by each type. Analysis of actual hourly load data suggests peaking units generate only 2.0 percent of the total energy. Intermediate units generate 18.5 percent and baseload units generate 79.5 percent of total energy.[1] As shown in Table 4-4, these energy weights produce a long-run cost of electricity generation under continued regulation that is equal to 3.93 cents per kWh. The long-run price of electricity is found by adding the cost of transmission and distribution to the long-run generation cost. This results in a long-run price of 5.02 cents per kWh.

While the calculations in Table 4-4 use pulverized coal-fired generation for baseload units to determine the long-run cost, it is also possible to use natural gas-fired combined cycle units for this purpose. Preliminary analyses showed that using combined-cycle units as baseload generation has very little impact on the final long-run cost. This result stems from the increased fuel cost of the combined-cycle unit at a high capacity factor effectively counteracting the higher capital cost of the pulverized coal unit. Similarly, when choosing a plant type to construct, a utility must consider the higher capital risk involved with the pulverized coal unit with the higher fuel cost risk of the combined cycle unit. For further discussion of the relative merits of natural gas vs. coal, please see Chapter 10.

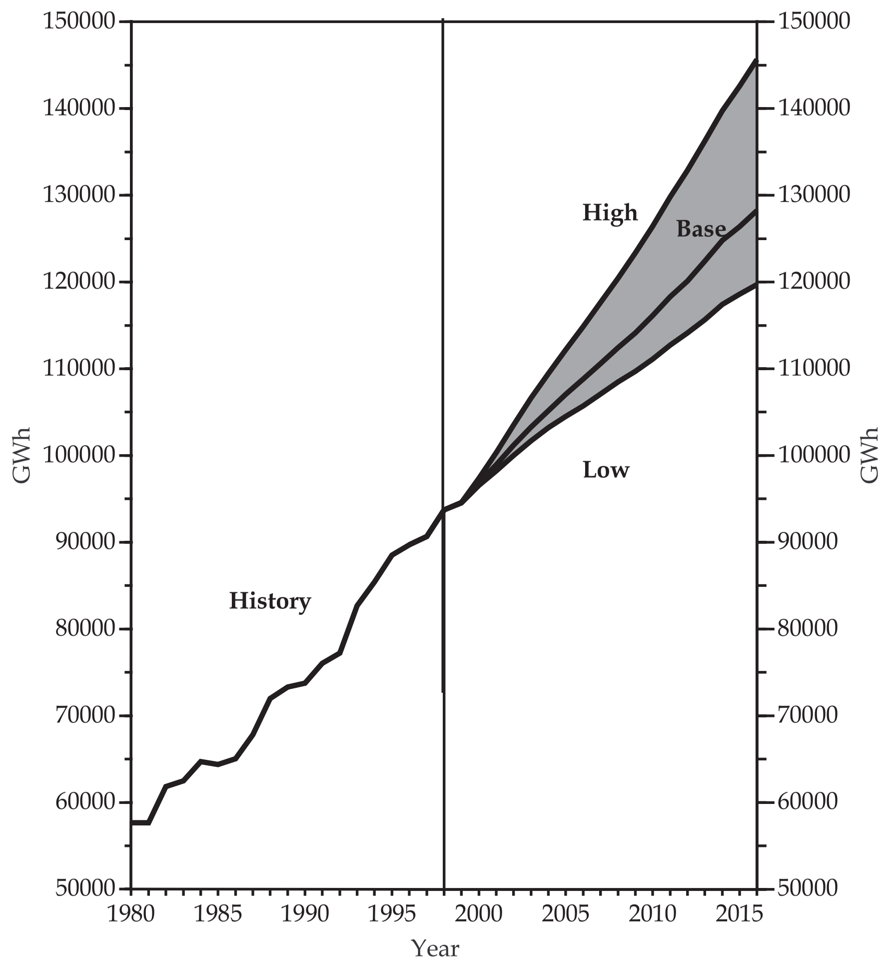
[1]The assumed energy shares, together with the assumed capacity factors, imply that the distribution of total capacity is 12 percent peaking units, 26 percent combined cycle units and 62 percent coal units.

FIGURE 4-5

Indiana Energy Requirements by Scenario in GWh

Year	Base	Low	High
1996	89698	89698	89698
1997	90662	90662	90662
1998	93729	93729	93729
1999	94561	94547	94575
2000	96867	96575	97393
2001	98922	98213	100334
2002	101170	100010	103522
2003	103298	101680	106635
2004	105179	103203	109439
2005	107058	104493	112169
2006	108833	105703	114882
2007	110601	107077	117653
2008	112433	108487	120434
2009	114148	109703	123370
2010	116124	111094	126425
2011	118291	112726	129805
2012	120130	114128	132877
2013	122389	115666	136255
2014	124797	117432	139759
2015	126406	118614	142588
2016	128237	119724	145659

Average Compound Growth Rates (%)			
Selected Periods	Base	Low	High
1980-85	2.22	2.22	2.22
1985-90	2.75	2.75	2.75
1990-96	3.32	3.32	3.32
1996-00	1.94	1.86	2.08
2000-16	1.77	1.35	2.55
1996-16	**1.80**	**1.45**	**2.45**



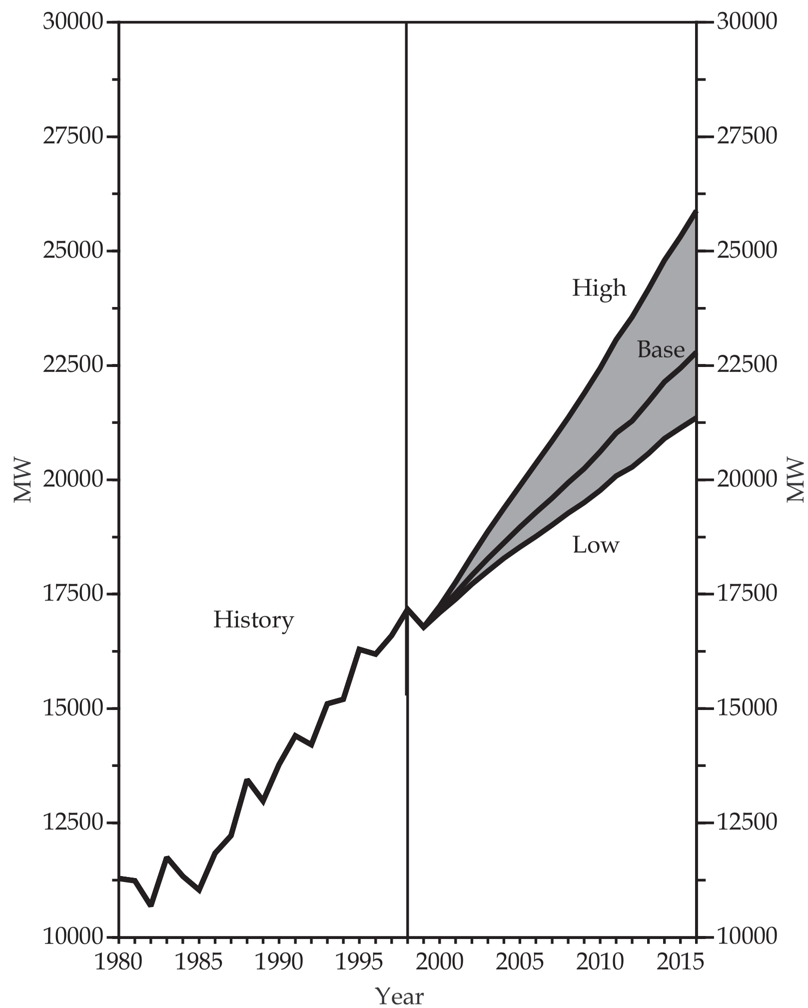
Notes: The shaded numbers in the table and the heavy line in the graph are historical values. (For an explanation on how SUFG arrives at these numbers, see Appendix H.)

FIGURE 4-6

Indiana Demand Requirements by Scenario in MW

Year	Base	Low	High
1996	16184	16184	16184
1997	16596	16596	16596
1998	17168	17168	17168
1999	16779	16777	16782
2000	17145	17095	17239
2001	17514	17394	17764
2002	17917	17720	18334
2003	18279	18006	18871
2004	18620	18288	19375
2005	18962	18529	19868
2006	19288	18759	20360
2007	19604	19012	20854
2008	19936	19273	21354
2009	20248	19501	21885
2010	20614	19768	22443
2011	21019	20084	23065
2012	21290	20283	23557
2013	21703	20571	24168
2014	22142	20901	24801
2015	22443	21132	25318
2016	22789	21354	25883

Average Compound Growth Rates (%)			
Selected Periods	Base	Low	High
1980-85	-0.11	-0.11	-0.11
1985-90	1.12	1.12	1.12
1990-96	0.81	0.81	0.81
1996-00	0.29	0.27	0.32
2000-16	1.43	1.12	2.05
1996-16	**1.73**	**1.40**	**2.38**



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

TABLE 4-2

Indiana Resource Additions (SUFG Scenarios) in MW

	Base				Low				High			
Year	Peaking	Cycling	Base Load	Total	Peaking	Cycling	Base Load	Total	Peaking	Cycling	Base Load	Total
1996	0	143	27	170	0	143	27	170	0	143	27	170
1997	0	0	0	0	0	0	0	0	0	0	0	0
1998	0	0	45	45	0	0	45	45	0	0	45	45
1999	600	0	0	600	600	0	0	600	600	0	0	600
2000	300	0	0	300	300	0	0	300	300	0	0	300
2001	350	0	0	350	200	0	0	200	500	0	0	500
2002	0	200	0	200	300	0	0	300	275	200	0	475
2003	0	0	500	500	150	0	0	150	125	0	500	625
2004	300	0	0	300	0	0	500	500	125	0	500	625
2005	0	0	0	0	0	0	0	0	0	200	0	200
2006	0	0	500	500	150	0	0	150	150	0	500	650
2007	150	0	0	150	0	0	0	0	0	0	500	500
2008	0	0	500	500	0	0	500	500	125	200	0	325
2009	0	175	0	175	150	0	0	150	0	175	475	650
2010	150	200	0	350	0	200	0	200	300	200	0	500
2011	0	175	500	675	150	200	0	350	125	200	500	825
2012	125	200	0	325	0	0	500	500	0	175	500	675
2013	275	200	0	475	0	200	0	200	125	200	500	825
2014	125	0	500	625	125	200	0	325	125	175	500	825
2015	375	675	0	1050	375	325	475	1175	400	500	450	1350
2016	100	0	500	600	0	375	0	375	300	400	0	700
Total	2850	1968	3072	7890	2500	1643	2047	6190	3575	2768	4997	11365

TABLE 4-3			
New Generation Costs Under Continued Regulation			
	Combustion Turbines	**Combined Cycle Units**	**Pulverized Coal Units**
Capital Cost ($/kW)	330	490	1150
Capacity Factor (%)	10	40	80
Fixed O&M ($/kW)	13.77	36.36	34.00
Variable O&M ($/MWh)	0.34	0.55	2.10
Heat Rate (BTU/kWh)	11,280	7,340	9,800
Fuel Cost ($/mmBTU)	2.5	2.5	1.0
Energy Weight	0.020	0.185	0.795

TABLE 4-4				
Long-Run Costs Under Continued Regulation (Cents/kWh)				
	Combustion Turbines	Combined Cycle Units	Pulverized Coal Units	Total
Average Capital Recovery	0.020*4.521	0.185*1.678	0.795*1.969	1.966
Average Fixed O&M	0.020*1.571	0.185*1.038	0.795*0.485	0.609
Average Variable O&M	0.020*0.034	0.185*0.055	0.795*0.210	0.177
Average Fuel Cost	0.020*2.820	0.185*1.835	0.795*0.980	1.175
Long-Run Average Cost				3.928

Note: The values in the last column represent the energy-weighted cost for all types of generators. They are found by multiplying the cost by the energy weight for each generator type and summing across all types.

CHAPTER 5
RESIDENTIAL ELECTRICITY SALES

Overview

SUFG uses both econometric and end-use models of residential electricity sales. These different modeling approaches have specific strengths and therefore, are complementary. The econometric model is used to separately project the number of customers with and 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 reestimated twice, once in 1988 and again in 1994. In addition, SUFG has acquired a proprietary end-use model, Residential End-Use Energy Modeling System (REEMS), which blends econometric and engineering methodologies to project energy use on a very disaggregated basis. REEMS is a descendant of the first generation of end-use models developed at Oak Ridge National Labs (ORNL) during the late 1970s. The end-use model, because of its greater data requirements, was implemented at the statewide level from 1980 Census data for Indiana supplemented by Indiana utility data and other data sources.

Although these modeling approaches are complementary, these two models forecast very differently. Given the same set of primary inputs, the econometric model projects nearly twice as much growth as the end-use model. Experience has shown the econometric model to be much more accurate. Residential sales growth (historical, weather normalized) has been between 2.0 and 2.5 percent every year since 1987. SUFG's residential electricity sales projections for the same period, based on the econometric model, have been in the same range. For this reason, SUFG continues to rely on its econometric model to project residential electricity sales and uses REEMS to help develop estimates of residential sector DSM program impacts.

A general description of the residential econometric model follows, along with a brief historical perspective on residential electricity consumption trends in Indiana. A more technical description of the residential econometric model is provided in Appendix B. REEMS, the ORNL-like end-use model, is not described in this report (see SUFG's 1987 forecast report for a description of REEMS' methodology and projections).

Historical Perspective

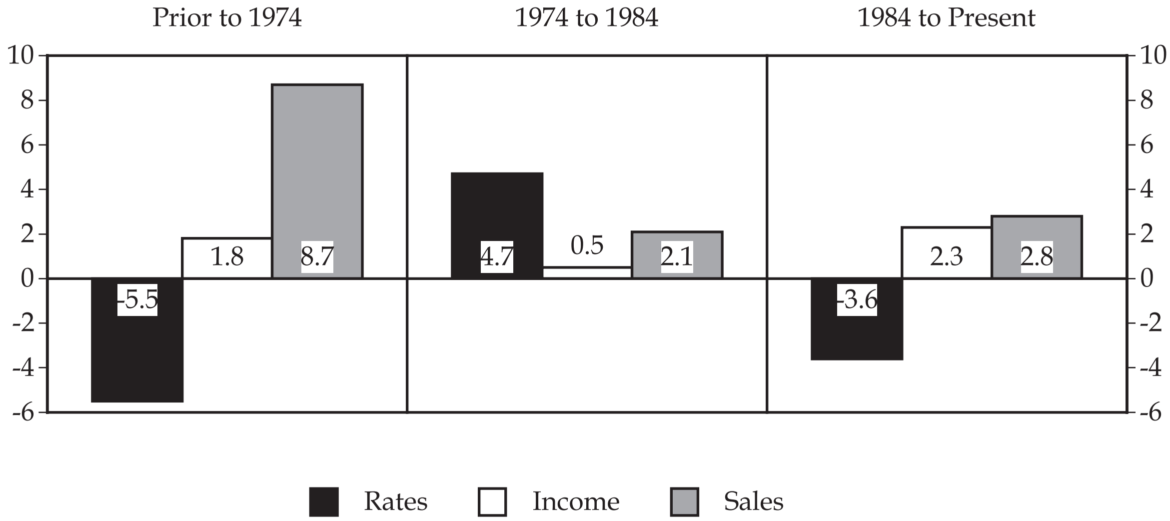
The growth in residential electricity consumption has generally reflected changes in economic activity, i.e., real household income, real energy prices and total households. Each of the last three ten-year periods has been characterized by distinctly different trends in these market factors and in each case, residential electricity sales growth has reflected the change in market conditions (see Figure 5-1).

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

In the decade following the embargo, the growth in residential electricity sales slowed dramatically. Except for some softening in electricity prices during 1979-81, real electricity prices climbed at approximately the same rate during the post-embargo era as they had fallen during the pre-embargo era. This resulted in a swing in electric prices of more than 10 percent. Declining at an annual rate of slightly less than one percent (a swing of 2.5 percent per year), growth in real household income was a miniscule 0.5 percent. The housing market also went from boom to bust, averag-

FIGURE 5-1

Historical Trends in the Residential Sector
(Annual Percent Changes)



ing only half the growth of the pre-embargo period. This turnaround in economic conditions and electricity prices is reflected in the dramatic decline in the growth of residential electricity sales from nearly 9 percent per year prior to 1974, to just 2 percent per year over the next decade.

Events turned again during the mid-1980s. Real household income grew at more than the pre-embargo rate, 2.3 percent per year. Real electricity prices declined 3.6 percent per year at two thirds the pre-embargo rate. Households grew only at a slightly higher rate than in the post-embargo decade, about 0.9 percent per year. Despite these more favorable market conditions, annual sales growth increased only 0.7 percent to 2.8 percent per year (weather normalized).

Several market factors, not discussed above, contributed to the small difference in sales growth between the post-embargo and most 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 have caused natural gas to recapture market share. Next in importance are equipment efficiency standards and the availability of more efficient appliances. Appliance efficiency improvement standards did not begin until late in the post-embargo era. Lastly, appliance saturations tend to grow more slowly as they approach full market saturation and the major residential end uses are nearing full saturation.

Model Description

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

Space Heating Fuel Choice Model

A logit model, based on relative fuel costs, is used to project space heating fuel choice (electric vs. non-electric). This model was estimated from data for the five Indiana IOUs. The dependent variable in this model, referred to as a logit, is the ratio of electricity's share of new space heating systems to that of all other fuels. Market share, or penetration, is defined as the change in electric space heating customers as a fraction of net new customers. The advantages of modeling penetration rather than saturation are that penetration captures current activity, is independent of the rate of customer growth and exhibits greater year-to-year variation. See Appendix B for a detailed explanation of SUFG's econometric logit fuel choice model, as well as the sensitivity of the fuel choice model to changes in relative fuel costs. Under SUFG's base case assumptions of stable electricity prices and stable fossil fuel prices, the fuel choice model projects the penetration of electric space heating to average about 30 percent over the forecast horizon (for the five IOUs combined).

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

Average kWh Sales: Non-Electric Heating Customers

About 80 percent of all residential customers are non-electric heating customers. Prior to 1974, average electricity consumption by these customers increased about 6 percent per year. Since 1974, average use has increased only slightly, averaging about 0.5 percent per year from 1975-85 and about 0.8 percent thereafter.

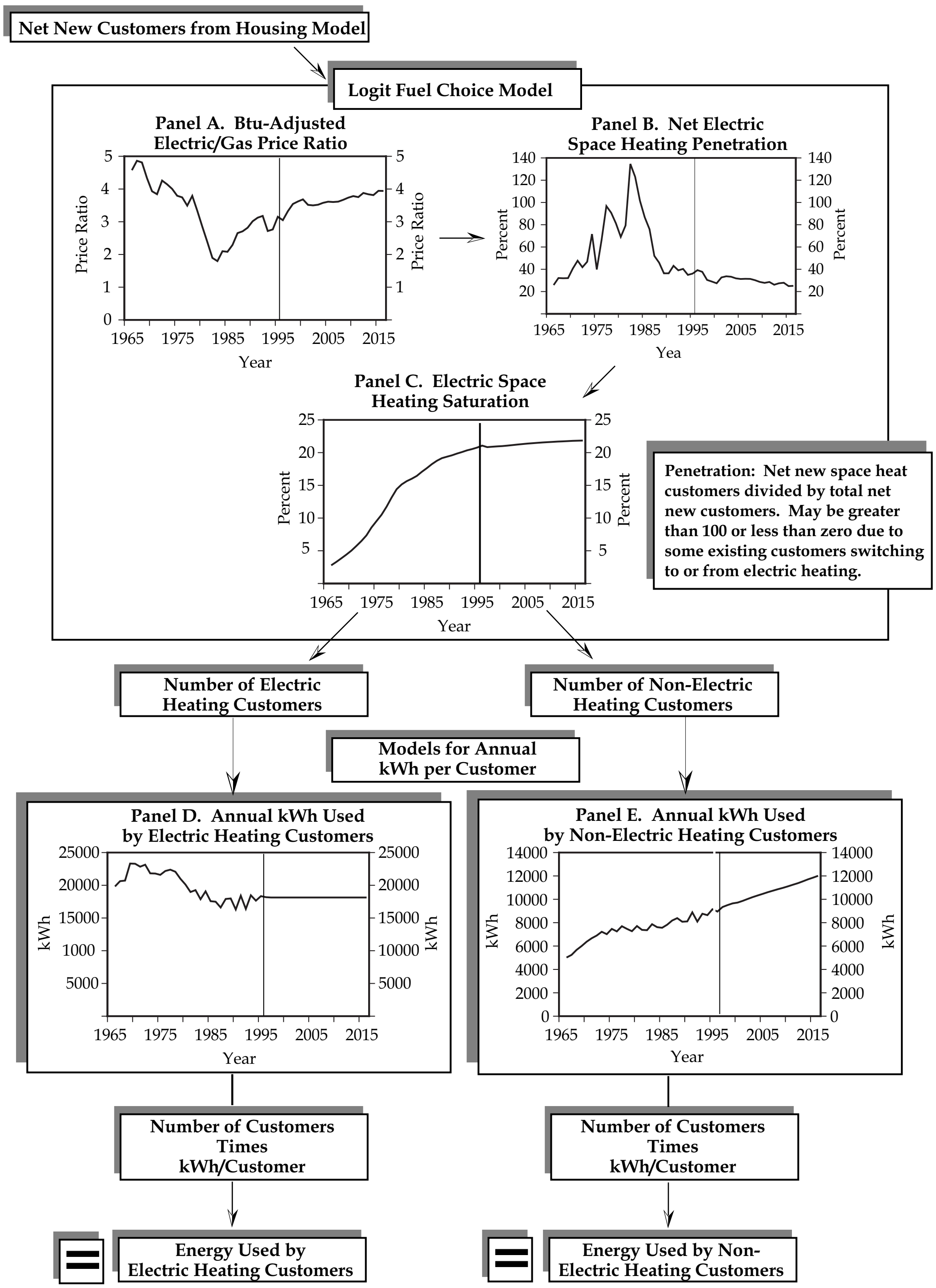
A robust econometric demand model, known as the log-log expenditure share model, is used to estimate the demand for electricity by non-electric heating customers. This relationship is capable of picking up emerging nonlinearities or saturation effects not detected by ordinary demand models. This is especially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

Average kWh Sales: Electric Space Heating Customers

Average sales to electric space heating customers declined significantly throughout the 1970s and 1980s (see Panel D in Figure 5-2). This downward trend is most likely attributable to lower consumption by new electric space heating customers (better insulated

FIGURE 5-2

Structure of Residential Econometric Model



buildings, heat pumps and a changing mix of type and size of new electrically heated homes) than it is to decreases in consumption by existing customers (i.e., lower thermostat settings and envelope retrofits), although the latter has most likely occurred as well. The application of econometric analysis to capture these effects is not likely to provide reliable or even plausible results on an aggregate level. The heterogeneity among customers over time is too great. SUFG performed limited econometric analysis of this component without success.

Consumption data for the last several years indicate that the rapid decline in average energy consumption by electric space heating customers has leveled off after falling nearly 20 percent between the late 1970s and the mid-1980s. A review of the thermal integrity and electric space heating technology curves from the residential end-use model suggested that savings beyond 20 percent would require a substantial increase in the real price of electricity. Given this result, in combination with the outlook for constant or declining real electricity prices during the forecast period and the apparent leveling off of the decline in usage in recent years, SUFG assumes that the space heating component of a space heating customer's consumption will remain constant throughout the forecast period at about 7,000 kWh per year.

The non-space heating component of an electric space heating customer's consumption currently averages about 11,000 kWh. Changes in real incomes, real electricity prices and real appliance prices should have a much less effect on future consumption levels since electric space heating customers already have very high saturations of all major household appliances. Thus, SUFG assumes that this component of a space heating customer's consumption will also remain constant during the forecast period (marginal efficiency improvements will offset marginal saturation and utilization increases). These are the same assumptions made for our first forecast in 1987. They have been reviewed each year as new data have become available.

Summary Of Results

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

Model Sensitivities

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

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

Indiana Residential Electricity Sales Projections

Actual sales, as well as past and current projections, are shown in Figure 5-3. The boxed numbers in the table and the heavy line in the graph are historical consumption. The growth rate for the current base projection of Indiana residential electricity sales is 1.76

TABLE 5-1

Residential Model Sensitivities

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

percent, with a projection somewhat higher than SUFG's 1996 projection. However, the recent growth projections are significantly less than the 2.0 percent projected forecasts prior to 1994. The recent projections are lower despite little or no change in the growth rates for the major explanatory variables shown in Table 5-2. It is lower because SUFG's 1994 elasticity estimates for average kWh sales to non-electric space heating customers declined by a factor of almost a third (in absolute value) from previous estimates. Interestingly, the elasticity estimates used in the current and 1994 SUFG projections are quite similar to those originally estimated in 1987 (see Table B-1, Appendix B). Table 5-3 summarizes SUFG's base projections of residential electricity sales growth since 1994. These projections are broken down by the portion of the growth rate attributable to the growth in number of customers and growth in utilization per customer, before and after DSM. As the table shows, approximately 40 percent of projected sales is attributable to customer growth and 60 percent to changes in electric intensity (price and income effects and DSM). The net effect of changes in energy prices is to increase electric intensity about 0.1 percent per year. The small amount of residential DSM, primarily load shifting, has virtually no effect on residential electric intensity growth. The remaining growth in electric intensity is accounted for by income growth and declining real appliance prices.

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

Indiana Residential Electricity Price Projections

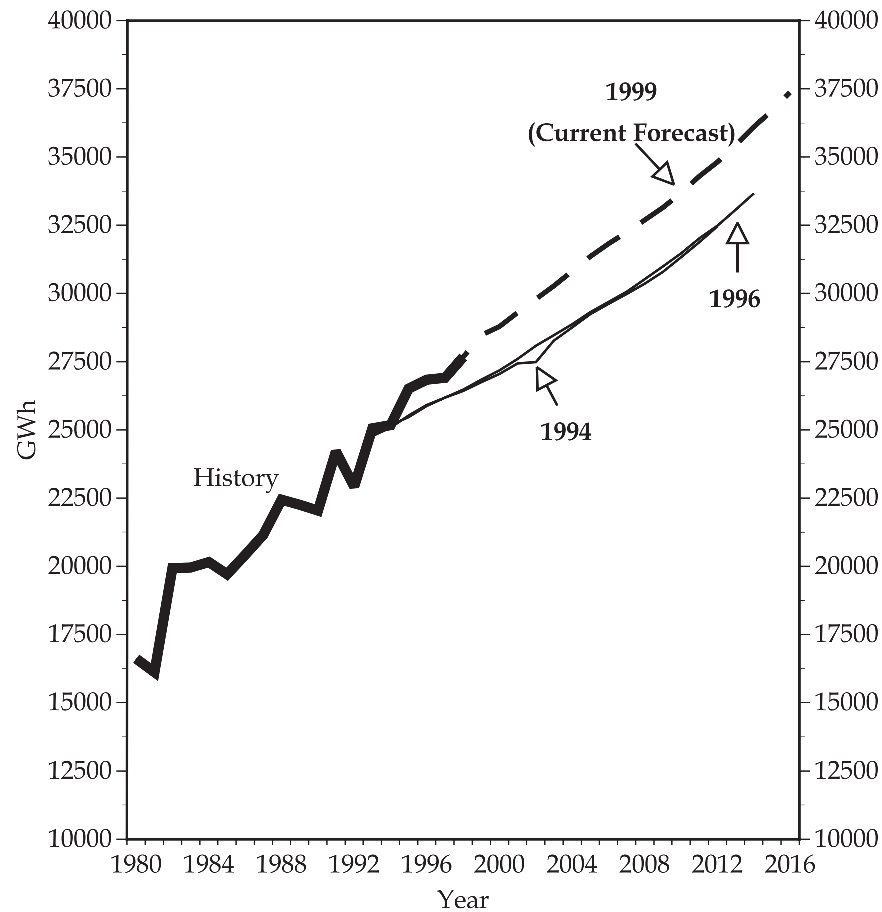
Historical values and current projections of residential electricity prices are shown in Figure 5-5. In real terms residential electricity prices have been declining since the mid-1980s. SUFG projects this trend to continue until the end of the century when slower declines in utility steam coal prices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

FIGURE 5-3

Indiana Residential Electricity Sales in GWh (Historical, Current and Previous Forecasts)

Year	Year of Forecast 1994	1996	1999
1990	22037	22037	22037
1991	24215	24215	24215
1992	23008	22916	22916
1993	24777	25060	25060
1994	25079	25176	25176
1995	25519	25463	26513
1996	25914	25880	26833
1997	26186	26183	26909
1998	26432	26471	27693
1999	26742	26833	28468
2000	27048	27179	28783
2001	27431	27604	29300
2002	27485	28080	29791
2003	28274	28470	30280
2004	28754	28863	30811
2005	29237	29315	31353
2006	29617	29688	31823
2007	29984	30068	32242
2008	30354	30525	32686
2009	30795	30988	33154
2010	31326	31472	33693
2011	31878	32020	34299
2012	32453	32480	34813
2013		33070	35430
2014		33662	36109
2015			36696
2016			37366

Average Compound Growth Rates			
Forecast Period	1992-12	1994-14	1996-16
	1.73	1.46	1.67



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

TABLE 5-2				
Residential Model Explanatory Variables – Growth Rates By Forecast (%)				
Variable	**Current Scenario (1996-2016)**			**1996 Forecast**
	Base	**Low**	**High**	**Base**
Number of Customers	0.66	0.65	0.69	0.64
Appliance Prices	-3.00	-3.00	-3.00	-3.00
Electric Rates	-0.26	-0.21	-0.23	-0.06
Natural Gas Price	-0.71	-0.71	-0.71	-0.21
Oil Prices	0.25	0.25	0.25	0.66
Household Income	1.85	1.62	2.42	1.08

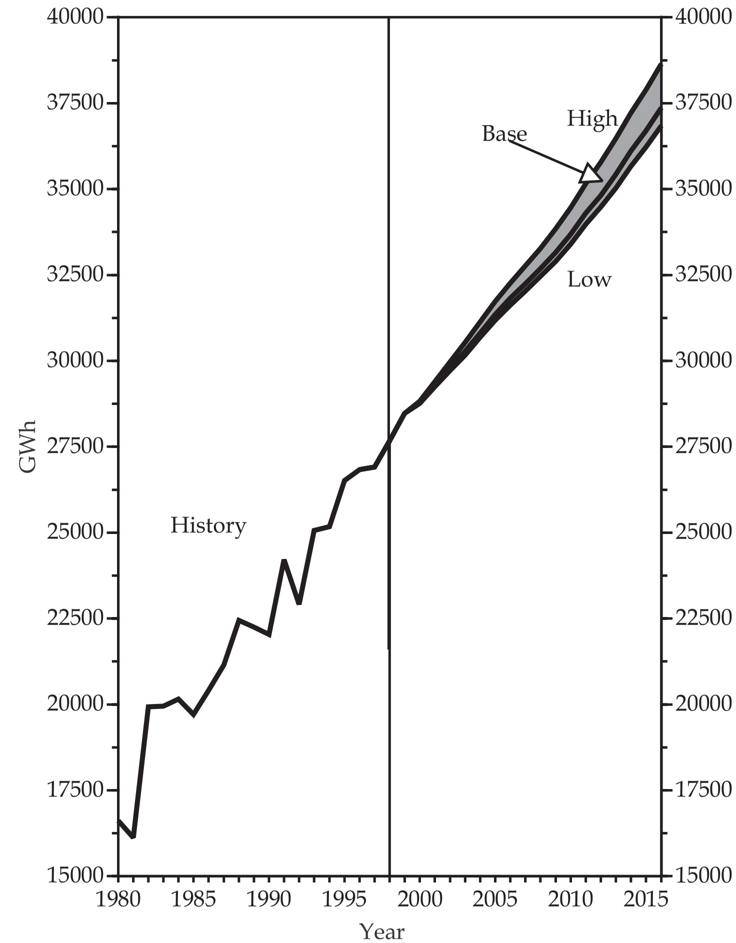
TABLE 5-3					
History of SUFG Residential Sector Growth Rates (%)					
Forecast	**No. of Customers**	**Prior to DSM**		**After DSM**	
		Utilization	**Sales Growth**	**Utilization**	**Sales Growth**
1999 SUFG Base (1996-2016)	0.66	1.01	1.67	1.01	1.67
1996 SUFG Base (1994-2014)	0.64	0.95	1.59	0.90	1.46
1994 SUFG Base (1992 - 2012)	0.63	1.24	1.87	1.14	1.73

FIGURE 5-4

Indiana Residential Electricity Sales by Scenario in GWh

Year	Base	Low	High
1996	26833	26833	26833
1997	26909	26909	26909
1998	27673	27673	27673
1999	28468	28468	28472
2000	28783	28761	28822
2001	29300	29257	29405
2002	29791	29717	29970
2003	30280	30172	30538
2004	30811	30692	31139
2005	31353	31187	31732
2006	31823	31620	32266
2007	32242	32035	32765
2008	32686	32460	33267
2009	33154	32899	33843
2010	33693	33396	34458
2011	34299	33974	35164
2012	34813	34477	35780
2013	35430	35028	36476
2014	36109	35659	37218
2015	36696	36226	37886
2016	37366	36846	38643

Average Compound Growth Rates			
Selected Periods	Base	Low	High
1980-85	3.48	3.48	3.48
1985-90	2.26	2.26	2.26
1990-96	3.34	3.34	3.34
1996-00	1.71	1.75	1.80
2000-16	1.64	1.56	1.85
1996-16	**1.67**	**1.60**	**1.84**



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

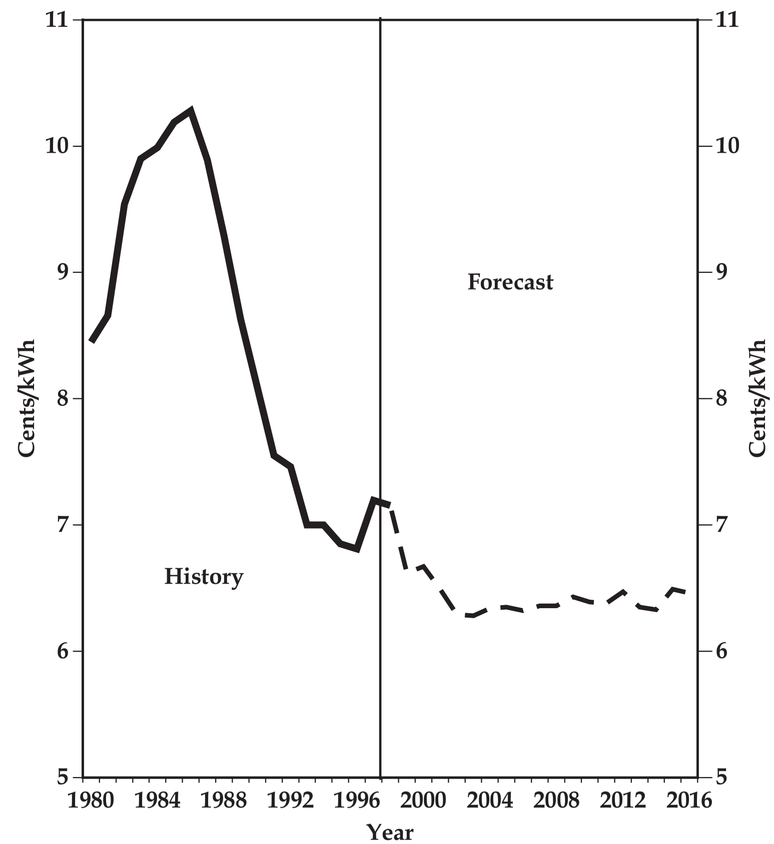
FIGURE 5-5

Indiana Residential Base Real Price Projections (in 1996 Dollars)

Year	Real Price
1980	8.45
1981	8.66
1982	9.54
1983	9.90
1984	9.99
1985	10.19
1986	10.28
1987	9.89
1988	9.29
1989	8.63
1990	8.09
1991	7.55
1992	7.46
1993	7.00
1994	7.00
1995	6.85
1996	6.81
1997	7.20
1998	6.65

Year	Real Price
1999	6.62
2000	6.67
2001	6.49
2002	6.29
2003	6.28
2004	6.34
2005	6.35
2006	6.32
2007	6.36
2008	6.36
2009	6.43
2010	6.39
2011	6.38
2012	6.47
2013	6.35
2014	6.33
2015	6.49
2016	6.46

Average Compound Growth Rates	
Forecast Period	(%)
1980-85	3.81
1985-90	-4.50
1990-96	-2.84
1996-00	-0.53
2000-16	-0.19
1996-16	-0.26



Energy-Weighted Average for Five IOUs

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

CHAPTER 6
COMMERCIAL ELECTRICITY SALES

Overview

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

Prior to 1993, SUFG relied on its econometric model to project commercial electricity sales. SUFG used the end-use model for general comparison purposes and for its structural detail. (CEDMS estimates commercial floor space for building types and estimates energy use for end uses within each building type.) SUFG also took advantage of the building type detail in CEDMS to construct the major economic drivers for its econometric model (discussed in Appendix C). In 1993, SUFG made CEDMS its primary commercial sector forecasting model for several reasons. First, based on experience with the model over the last several years, SUFG is now confident it provides realistic energy projections under a wide range of assumptions. Next, in contrast to the significant differences between the residential end-use and econometric model projections (discussed in Chapter 5), the differences between the commercial models are small since both the econometric model and CEDMS forecast similar changes in electric intensity. Another advantage of relying on CEDMS as the primary forecasting model is to provide consistency between SUFG's energy projections and the frequent analyses performed by SUFG staff that require the structural detail provided by an end-use model. Perhaps the best example of such analyses is DSM impacts. SUFG is committed to implementing state-of-the-art end-use forecasting models in all three major customer sectors for each major service area in the state. CEDMS is the first of these models available for implementation. The details of implementing CEDMS at the state and service area level are described in Appendix C.

Historical Perspective

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

Changes in electric intensity, expressed as changes per square foot of energy-weighted floor space, arise from changes in building and equipment efficiencies as well as changes in equipment utilization, end-use saturations and new end uses, i.e., personal computers in office buildings. Electric intensity increased rapidly during the era of cheap energy (4.7 percent per year) as seen in Figure 6-1. This trend was interrupted by the significant upward swing in electricity prices during 1974-84, which resulted in a decrease in energy intensity. As electricity prices fell again during the 1984-96 period, electric intensity continued to decline but at a slower rate (-0.1 percent). 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.

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.

COMMERCIAL ELECTRICITY SALES

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

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

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

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.

FIGURE 6-1

Historical Trends in the Commercial Sector (Annual Percent Changes)

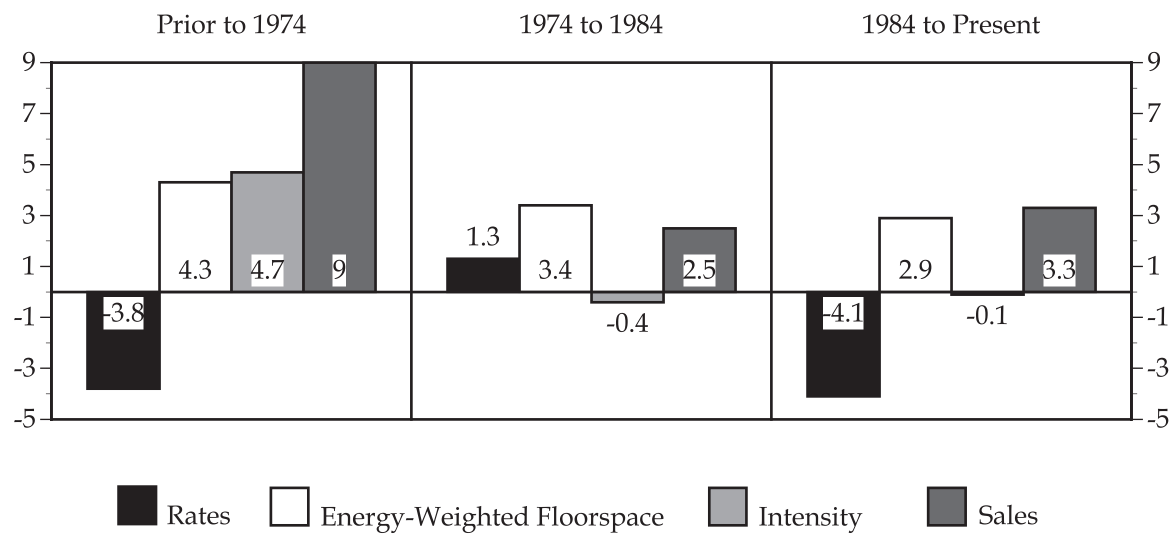
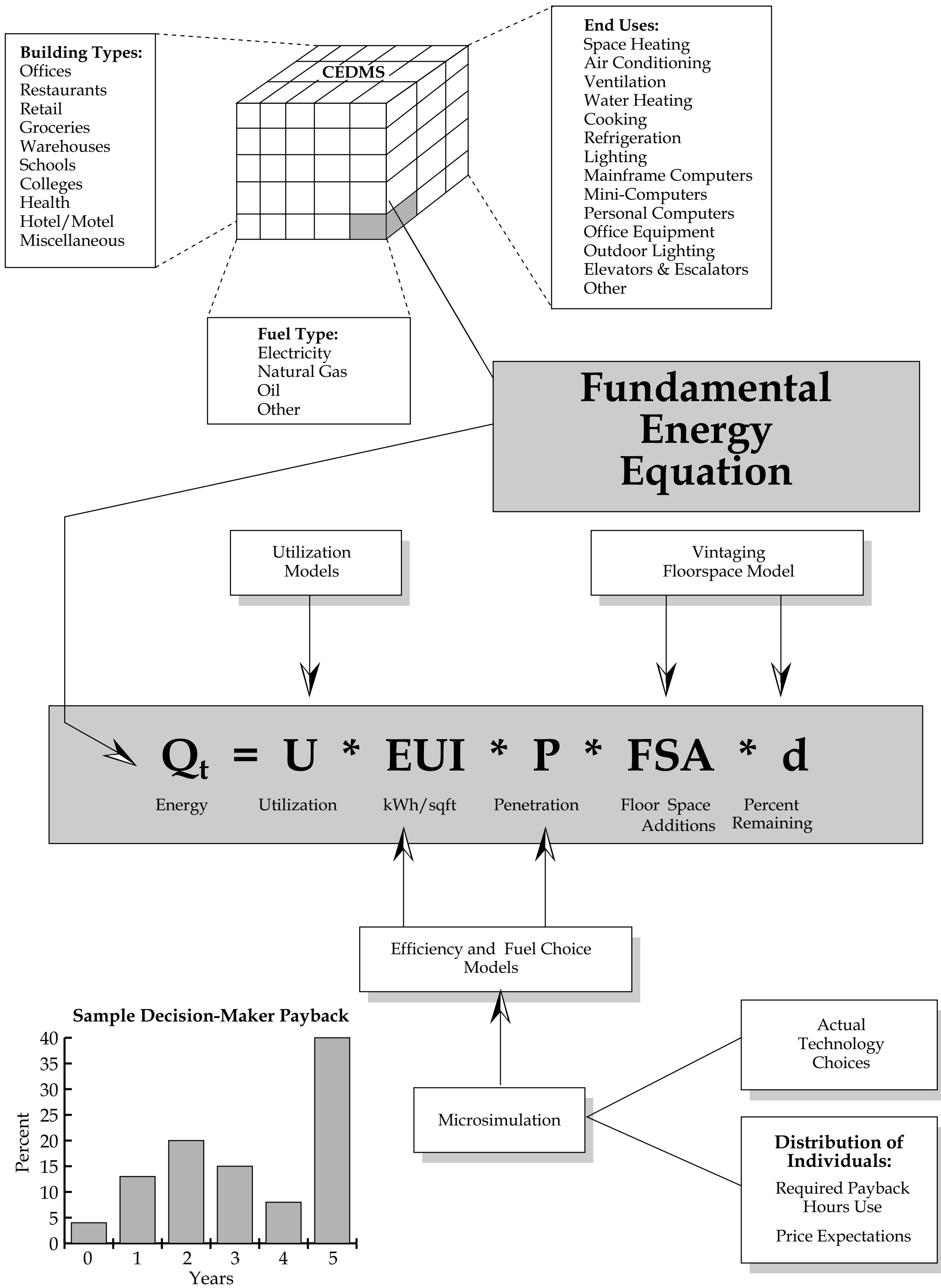


FIGURE 6-2

Commercial End-Use Energy Modeling System



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

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

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

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

Summary Of Results

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

Model Sensitivities

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

Indiana Commercial Electricity Sales Projections

Historical data as well as past and current projections are illustrated in Figure 6-3. The shaded num-

TABLE 6-1

Commercial Model Sensitivities

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

bers in the table and the heavy line in the graph are historical consumption. As can be seen, the current base projection of Indiana commercial electricity sales growth is 2.25 percent. The growth rates for the major explanatory variables are shown in Table 6-2. Table 6-3 summarizes SUFG's base projections of commercial electricity sales growth since 1992. Floor space growth accounts for about 2 percent growth annually. The net effect of changes in energy prices and floor space is to increase electricity use about 0.1 to 0.6 percent per year. The relatively small DSM programs have virtually no effect. Thus, practically all projected sales growth is attributable to floor space growth, with a lessor contribution from increased intensity.

As shown in Figure 6-3, the current projection is very similar to the 1996 forecast. This is due to similar growth in floorstock and electric intensity in the two forecasts. Finally, Table 6-3 indicates that the impact of utility-sponsored DSM programs is not significant in the current forecast and utility estimates of future DSM are much lower than those used in the 1996 forecast.

As shown in Figure 6-4, the growth rates for the low and high scenarios are about 0.2 percent lower and 1.3 percent higher than the base scenario, respectively. These differences are almost entirely due to a difference in floor space growth. As shown in Table 6-2, energy-weighted floorspace grows much faster in the high scenario relative to the base and low scenarios. This causes the asymmetry in the scenario projections relative to the base.

Indiana Commercial Electricity Price Projections

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

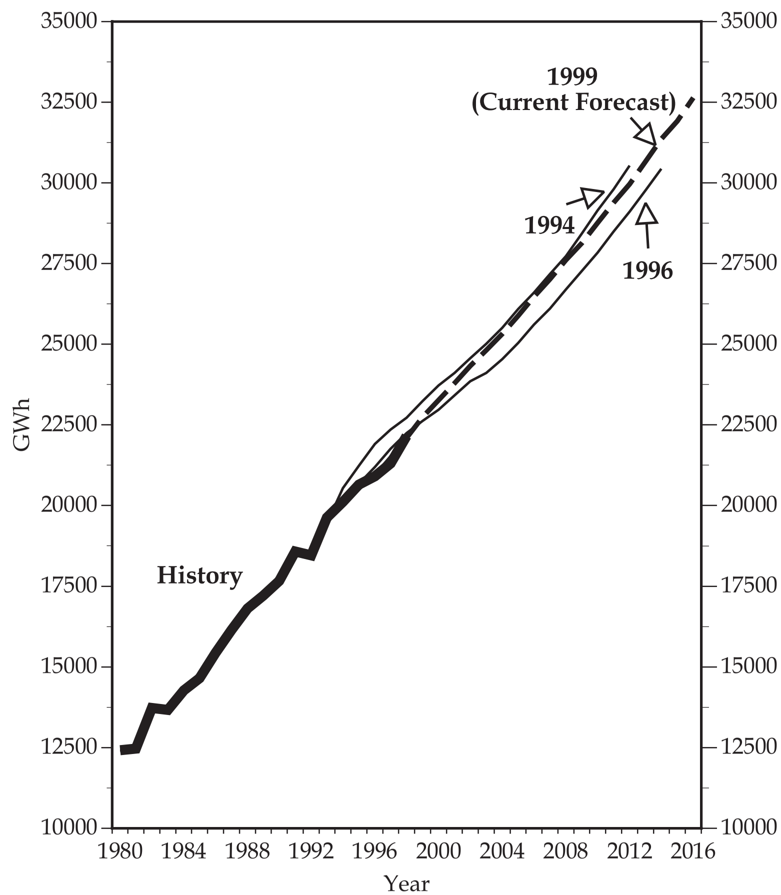
FIGURE 6-3

Indiana Commercial Electricity Sales in GWh (Historical, Current and Previous Forecasts)

Year	1994	1996	1999
	Year of Forecast		
1990	17659	17659	17659
1991	18580	18580	18580
1992	18456	18456	18456
1993	19459	19627	19627
1994	20539	20116	20116
1995	21237	20677	20646
1996	21912	21196	20909
1997	22359	21764	21303
1998	22723	22243	22161
1999	23236	22626	22738
2000	23722	22969	23271
2001	24106	23420	23795
2002	24566	23856	24333
2003	25016	24110	24815
2004	25508	24542	25319
2005	26097	25041	25883
2006	26596	25611	26471
2007	27172	26108	27014
2008	27734	26700	27609
2009	28436	27272	28139
2010	29145	27836	28759
2011	29808	28496	29392
2012	30537	29113	29959
2013		29777	30671
2014		30441	31357
2015			31917
2016			32636

Average Compound Growth Rates

Forecast Period	1992-12	1994-14	1996-16
	2.55	2.09	2.25



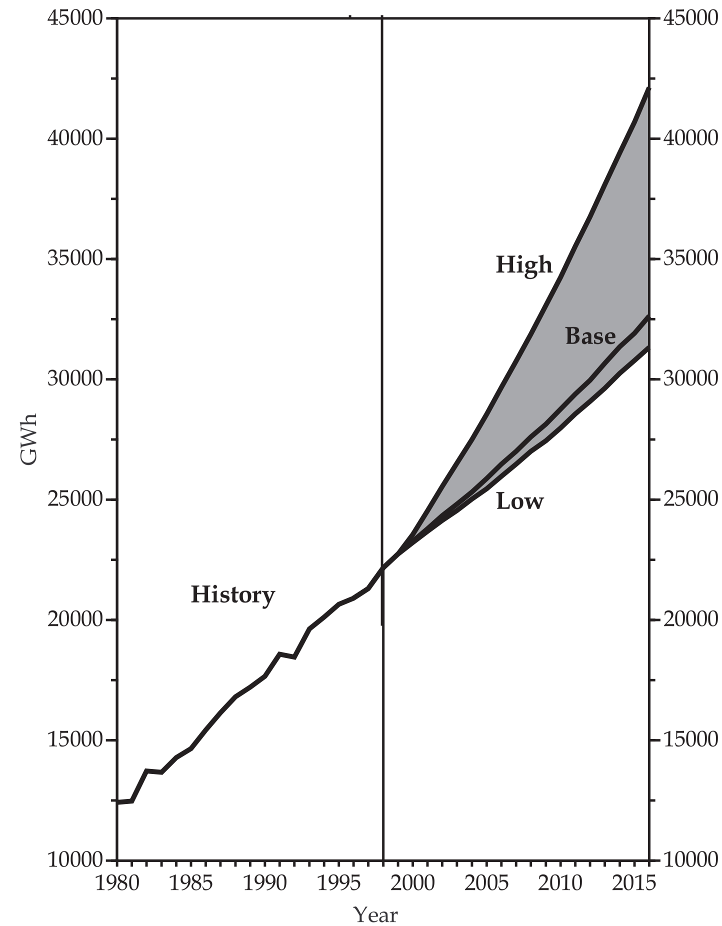
Notes: The shaded numbers in the table and the heavy line in the graph are historical requirements. (For an explanation on how SUFG arrives at these numbers, see Appendix H.)

FIGURE 6-4

Indiana Commercial Electricity Sales by Scenario in GWh

Year	Base	Low	High
1996	20909	20909	20909
1997	21303	21303	21303
1998	22161	22161	22161
1999	22738	22733	22742
2000	23271	23220	23551
2001	23795	23683	24536
2002	24333	24140	25544
2003	24815	24553	26519
2004	25319	25029	27503
2005	25883	25453	28549
2006	26471	25966	29675
2007	27014	26481	30754
2008	27609	27012	31882
2009	28139	27453	33072
2010	28759	27974	34246
2011	29392	28560	35541
2012	29959	29080	36759
2013	30671	29632	38085
2014	31357	30261	39423
2015	31917	30786	40697
2016	32636	31338	42131

Average Compound Growth Rates			
Selected Periods	Base	Low	High
1980-85	3.36	3.36	3.36
1985-90	3.81	3.81	3.81
1990-96	2.86	2.86	2.86
1996-00	2.71	2.66	3.02
2000-16	2.14	1.89	3.70
1996-16	2.25	2.04	3.57



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

TABLE 6-2				
Commercial Model -- Growth Rates (%) for Selected Variables (1999 SUFG Scenarios and 1996 Base Forecast)				
Variable	**SUFG Base (1996-2016)**	**SUFG Low (1996-2016)**	**SUFG High (1996-2016)**	**1996 Base Forecast (1994-2014)**
Electric Rates	-0.34	-0.31	-0.32	-0.20
Natural Gas Price	-0.65	-0.13	-0.13	1.13
Oil Prices	0.25	1.15	1.15	1.15
Energy-Weighted Floor Space	1.89	1.71	3.09	1.95

TABLE 6-3					
History of SUFG Commercial Sector Growth Rates (%)					
		Prior to DSM		After DSM	
Forecast	Electric Energy–Weighted Floorspace	Intensity	Sales Growth	Intensity	Sales Growth
1999 SUFG Base (1996-2016)	1.89	0.36	2.25	0.36	2.25
1996-SUFG Base (1994 - 2014)	1.95	0.31	2.26	0.14	2.09
1994 SUFG Base (1992 - 2012)	1.94	0.78	2.72	0.61	2.55

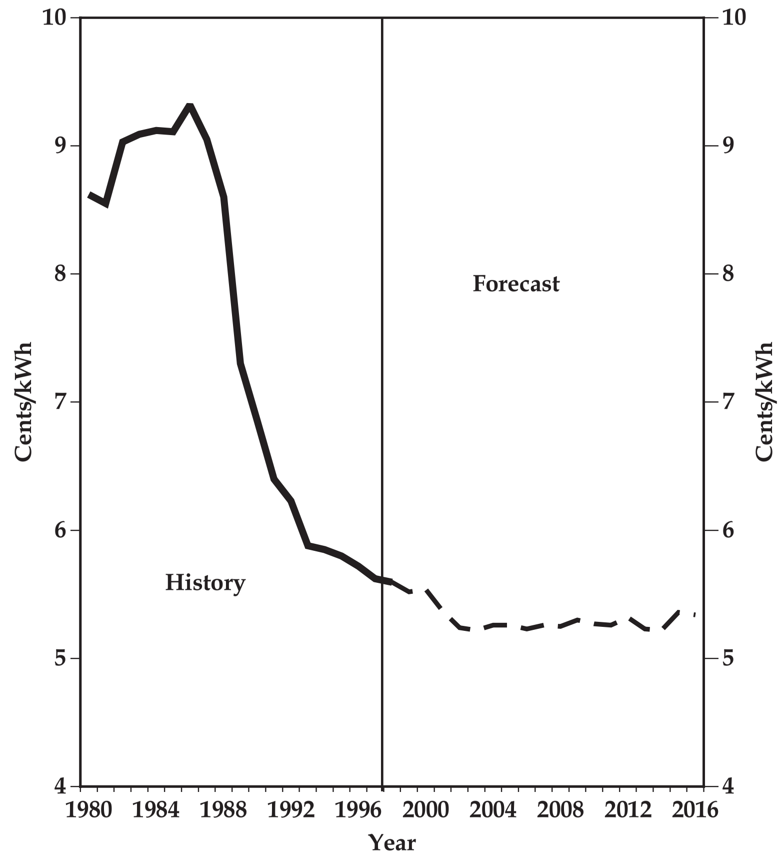
FIGURE 6-5

Indiana Commercial Base Real Price Projections (in 1996 Dollars)

Year	Real Price
1980	8.62
1981	8.55
1982	9.03
1983	9.09
1984	9.12
1985	9.11
1986	9.32
1987	9.05
1988	8.60
1989	7.30
1990	6.85
1991	6.40
1992	6.23
1993	5.88
1994	5.85
1995	5.80
1996	5.72
1997	5.62
1998	5.60

Year	Real Price
1999	5.52
2000	5.54
2001	5.37
2002	5.24
2003	5.22
2004	5.26
2005	5.26
2006	5.23
2007	5.26
2008	5.25
2009	5.30
2010	5.27
2011	5.26
2012	5.32
2013	5.23
2014	5.22
2015	5.36
2016	5.34

Average Compound Growth Rates	
Forecast Period	(%)
1980-85	1.12
1985-90	-5.55
1990-96	-2.95
1996-00	-0.80
2000-16	-0.23
1996-16	-0.34



Energy-Weighted Average for Five IOUs

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

CHAPTER 7
INDUSTRIAL ELECTRICITY SALES

Overview

SUFG currently uses several models to analyze and forecast electricity use in the industrial sector. The primary forecasting model is INDEED, an econometric model developed by the Electric Power Research Institute (EPRI), which is used to model the electricity use of 16 major industry groupings in the state. Additionally, a highly detailed process model of the iron and steel industry is used as an analytical tool to develop and evaluate alternative forecast scenarios for that industry. Originally developed as part of EPRI's industrial end-use modeling project, the iron and steel model has been substantially extended and refined over the years to reflect the technologies now available to the industry, which accounts for 12 percent of total electricity use in Indiana. The iron and steel model was used in the development of scenario-based forecasts for the steel industry. For the aluminum and foundries components of the primary metals industry, SUFG has developed scenario-based models. SUFG also uses an industrial motor drive model to evaluate and forecast the effect of motor technologies and standards. Since motors typically use 60 to 75 percent of all electricity in the industrial sector, they warrant specific analysis. For this forecast, the motor model was applied to the transportation industry. This motor model was developed by SUFG, and is patterned after the motor component in EPRI's Industrial End-Use Forecast Model (INFORM).

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

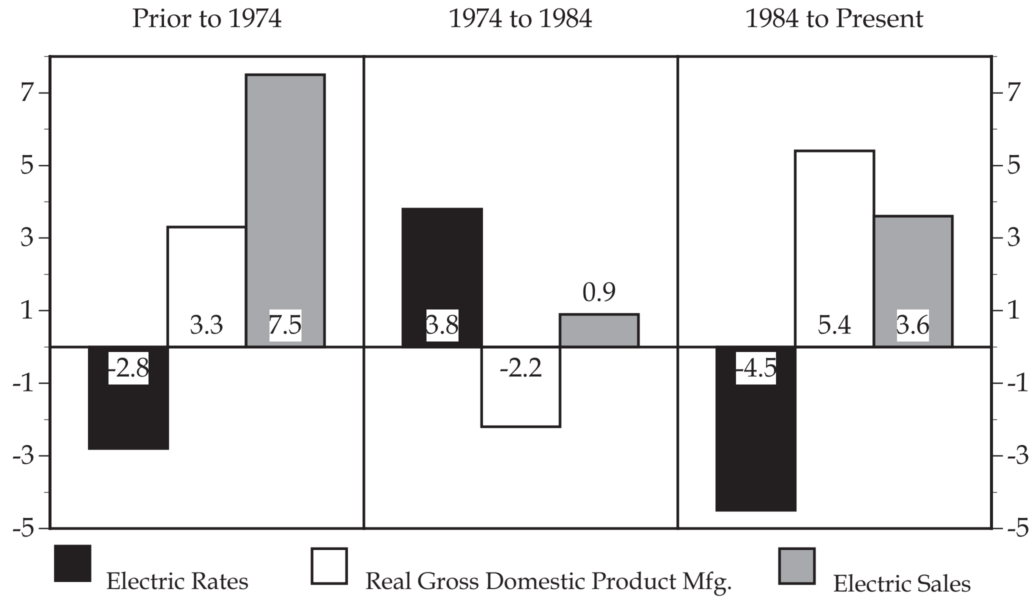
Historical Perspective

SUFG distinguishes three recent periods of distinctly different economic activity and growth — the decade prior to the oil embargo of 1974, 1974-1984 and the more recent period, 1984-1996. Figure 7-1 shows state growth rates for real manufacturing product, real electric rates and electric energy sales for the three periods.

During the decade prior to the OPEC oil embargo, industrial electricity sales increased 7.5 percent annually. In Indiana as elsewhere, sales growth was driven by the combined economic stimuli of falling electricity prices (2.8 percent per year in real terms) and growing manufacturing output (3.3 percent per year). During the decade following 1974, sales growth slowed as real electricity prices increased at an average rate of 3.8 percent per year and the state's manufacturing output declined at a rate of 2.2 percent per year. This turnaround in economic conditions and electricity prices resulted in a dramatic decline in the growth of industrial electricity sales from 7.5 percent per year prior to 1974 to 0.9 percent per year in the decade that followed. The fact that electricity sales increased at all is most likely attributable to increases in fossil fuel prices that occurred during the "energy crisis" of 1974-84. The recent period, 1984-1996, has witnessed another dramatic turnaround. The growth rate of industrial output once again becomes positive, and is substantially more than the rate observed prior to 1974. Real electricity prices

FIGURE 7-1

Historical Trends in the Industrial Sector
(Annual Percent Change)



in Indiana continued to decline in the industrial sector. These conditions caused electricity sales growth to average 3.6 percent per year during the last 12 years.

Model Description

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

The Econometric Model

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

Each model is driven by projections of selected industrial GSP over the forecast horizon provided by CEMR. Each industry's share of GSP is given in the first column of Table 7-1. Almost 70 percent of GSP is accounted for by the following industries: fabricated metals, 8 percent; transportation, 25 percent; electric machinery, 8 percent; primary metals, 11 percent; nonelectric machinery, 10 percent; and chemicals, 9 percent. The share of total electricity consumed by each industry is shown in column two. Both the chemical and primary metals industries are very electric intensive industries. Combined, they account for almost 50 percent of total industrial state electricity use.

Column three gives the current base projections for the major industries obtained from the most recent

FIGURE 7-2

Structure of SUFG's Industrial Energy Modeling System

SUFG looks at industrial energy use from three perspectives:

LEVEL I	**Econometric at 2-digit SIC level.**
LEVEL II	**Process model of iron and steel industry.**
LEVEL III	**Motor model to evaluate technologies and standards.**

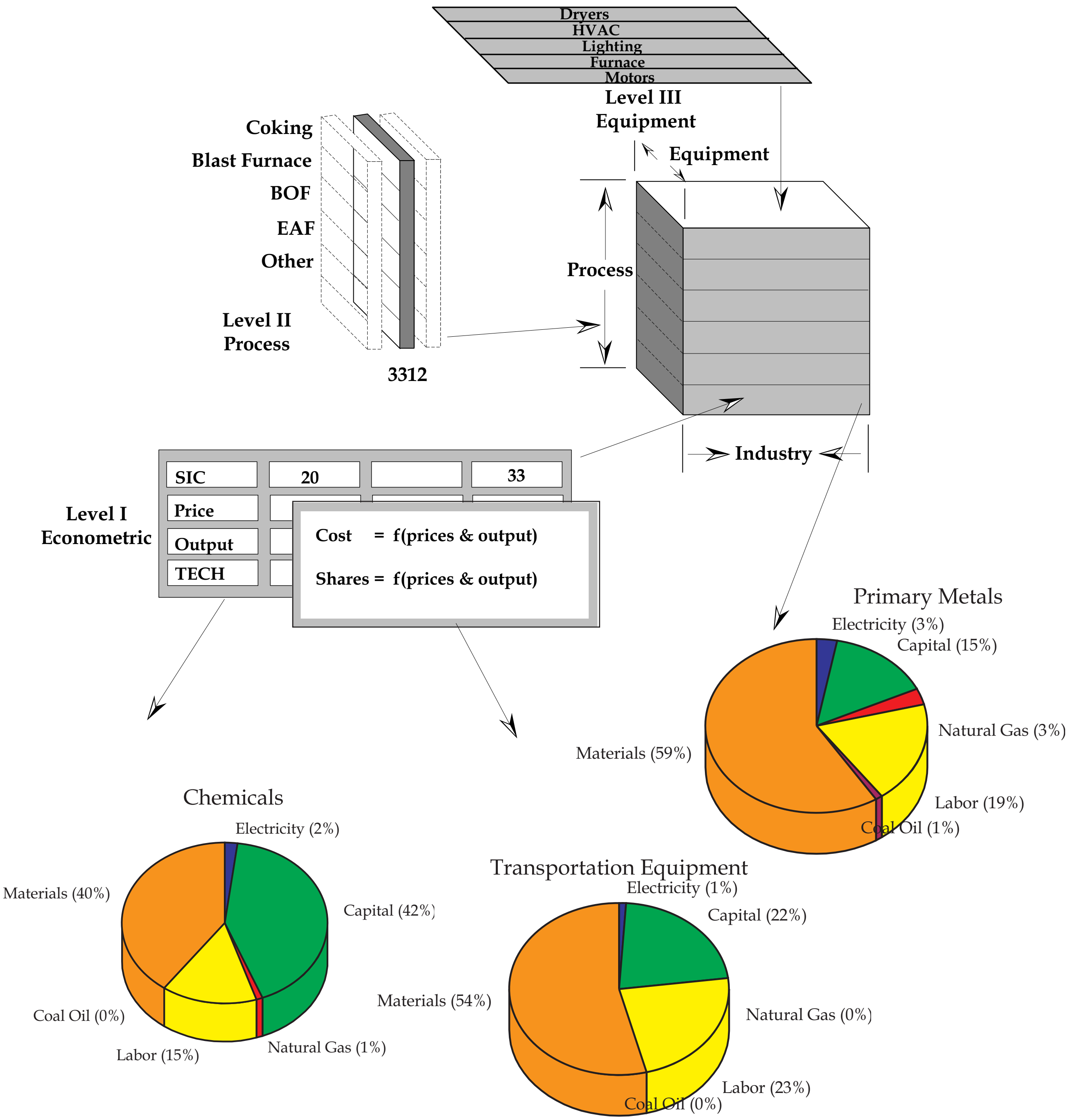


TABLE 7-1

Selected Statistics for Indiana's Industrial Sector (Prior to DSM) (%)

SIC	Name	Current Share of GSP	Current Share of Electricity Use	Forecast Growth in GSP Originating by Sector	Forecast Growth in Electricity Intensity by Sector	Forecast Growth in Electricity Use by Sector
20	Food	4.71	5.34	1.94	0.25	2.18
24	Wood	2.92	0.79	0.97	-0.04	0.93
25	Furniture	2.06	0.42	2.94	0.24	3.18
26	Pulp and Paper	1.74	2.90	0.87	0.16	1.03
27	Printing	3.76	1.37	3.46	0.56	4.02
28	Chemicals	9.20	19.30	0.38	0.71	1.09
29	Petroleum	0.02	2.52	1.24	0.00	1.24
30	Rubber/Plastics	4.88	5.16	2.01	0.19	2.20
32	Stone and Clay	2.16	4.96	-0.45	0.13	-0.32
33	Primary Metals	11.00	29.42	2.11	-0.68	1.43
34	Fabricated Metals	8.02	5.06	1.03	0.33	1.37
35	Non-Electric Machinery	9.86	5.06	2.36	0.27	2.63
36	Electric Machinery	8.34	5.20	2.93	0.13	3.05
37	Transportation	25.31	10.08	0.61	1.65	2.26
38	Instruments	2.35	1.18	2.30	0.25	2.55
39	Other	3.11	0.85	1.86	-1.50	0.35
	Total Manufacturing	**100.00**	**100.00**	**1.61**	**0.06**	**1.67**

CEMR forecast. As explained in Chapter 3, CEMR projections are developed using econometric models of the U.S. and Indiana economies. Manufacturing sector GSP projections are obtained by multiplying projected sector employment projections by a projection of GSP per employee, a measure of labor productivity.

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. Given the expenditure of electricity for each industry and its price, the quantity of electricity is solved for.

As described earlier in this chapter, INDEED captures the competition between the various inputs for their share of the cost of production by assuming firms seek the mix of inputs that minimize the cost of the given level of output. Unit costs of gas, oil, coal, capital, labor and materials are inputs to the SUFG system, while the cost per kWh of electricity is determined by the SUFG modeling system (see Appendix D). The current SUFG forecast assumes that real natural gas prices in the industrial sector decline at about 2.5 percent per year until the year 2000 and increase at a rate of about 0.8 percent per year thereafter. Other real fuel prices are assumed to follow a similar pattern, but are assumed to grow at a faster rate than gas after the year 2000. Unit costs for capital, labor and materials are consistent with the assumptions contained in the CEMR forecast of Indiana output growth.

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

The last column of Table 7-1 contains the projected annual percent increase in electricity sales by major industry. This projected increase is the sum of changes in GSP and kWh/GSP for each industry. Average industry electricity use across all sectors in the base scenario is expected to increase at an average of 1.67 percent per year over the forecast horizon (1.64 percent per year after accounting for DSM).

Summary of Results

Model Sensitivities

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

TABLE 7-2

Industrial Model Sensitivities

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

The Industry-Based Scenarios

Sales to Indiana's industrial sector account for over 45 percent of total Indiana electricity sales. Two industries — *primary metals* (i.e., steelmaking, aluminum, foundries) and *transportation equipment* (i.e., motor vehicles, parts) — account for almost 50 percent of the industrial sales. Because of their importance, detailed and comprehensive forecasts for output and electricity sales have been made by the SUFG staff for these industries to replace those provided by CEMR and SUFG's econometric modeling system. (Detailed descriptions of the mechanics of these forecasts can be found in SUFG's 1996 Indiana Electricity Projections documentation.)

Industrial Energy Projections: Current and Past

Past and current projections for industrial energy sales as well as overall annual average growth rates for the current and past forecasts are shown in Figure 7-3 in both tabular and graphic form. The shaded numbers in the table and the heavy line in the graph are historical sales. Thus, reading across the forecasts for a given year reveals the forecast error present in previous SUFG forecasts. As both the table and graph show, SUFG has tended to slightly underestimate the trajectory of electricity sales to the industrial sector

The impact of industrial sector DSM programs on growth rates for the 1994, 1996 and current forecasts are contained in Table 7-3. The table also disaggregates, the impact on energy growth of output, changes in the mix of output and electricity intensity, both with and without the impact of industry DSM programs.

The current forecast projects that industrial sector electricity sales will grow from its present level of approximately 35,000 GWh to over 48,000 GWh by 2016. This growth rate of 1.64 percent per year is considerably lower than the 2.25 percent rate projected for the commercial sector, but about the same as the 1.67 percent rate projected for the residential sector. As shown

TABLE 7-3

History of SUFG Industrial Sector Growth Rates (%)

Forecast	Output	Mix Effects	Electric Energy-Weighted Output	Prior to DSM		After DSM	
				Intensity	Sales Growth	Intensity	Sales Growth
1999 SUFG Base (1996-2016)	1.61	-0.17	1.44	0.23	1.67	0.20	1.64
1996 SUFG Base (1994-2014)	2.23	-0.20	2.03	0.38	2.41	0.28	2.31
1994 SUFG Base (1992-2012)	2.00	0.03	2.03	0.16	2.19	0.05	2.08

in Figure 7-3, the current forecast falls below the 1996 forecast throughout the entire forecast horizon. The difference between the current forecast and the 1996 forecast early in the forecast horizon may be attributed to the significant projected increase in self-generation in the steel industry.

Industrial Energy Projections: SUFG Scenarios

Figure 7-4 shows how industrial requirements differ by scenario. Industrial sales, in the high scenario, are expected to increase to over 53,000 GWh by 2016, 10 percent higher than the base projection. In the low scenario, industrial sales will grow slowly after the turn of the century, which results in only 42,000 GWh sales by 2016, 12.5 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, and the differing assumptions regarding the future of the primary metals and transportation industries. In the base scenario, CEMR expects GSP in the industrial sector to grow 1.61 percent per year during the forecast horizon. That rate is expected to be 2.28 percent in the high scenario and only 0.42 percent in the low scenario. This reflects the uncertainty regarding Indiana's industrial future contained in these forecasts. Similarly, the high and low scenarios reflect an optimistic and pessimistic view regarding the ability of Indiana's primary metals and transportation industries to compete with other producers.

Indiana Industrial Electricity Price Projections

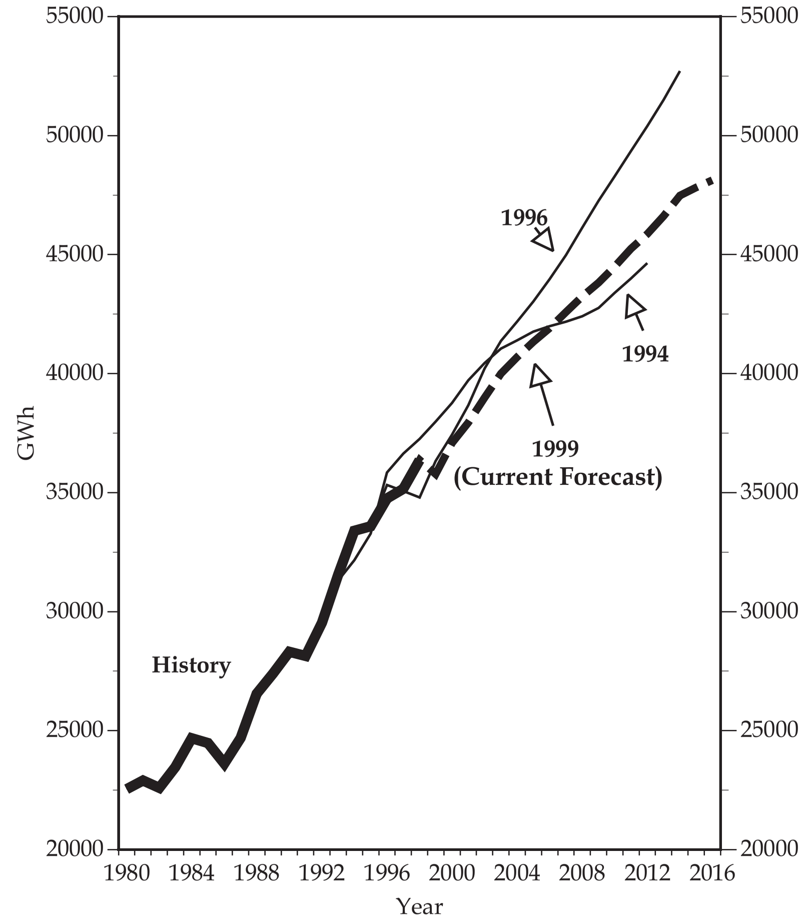
Historical values and current projections of industrial electricity prices are shown in Figure 7-5. In real terms, industrial electricity prices have been declining since the mid-1980s. SUFG projects this trend to continue until the end of the century when slower declines in utility steam coal prices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

FIGURE 7-3

Industrial Energy Sales in GWh
(Historical, Current and Previous Forecasts)

	Year of Forecast		
Year	1994	1996	1999
1990	28311	28311	28311
1991	28141	28141	28141
1992	29540	29540	29540
1993	31313	31562	31562
1994	32163	33395	33395
1995	33283	33580	33590
1996	35843	35324	34755
1997	36636	35072	35158
1998	37257	34802	36376
1999	37980	36336	35776
2000	38769	37427	37079
2001	39724	38666	37940
2002	40452	40214	38998
2003	41053	41370	40004
2004	41398	42201	40703
2005	41771	43022	41332
2006	41998	43965	41914
2007	42175	44979	42587
2008	42414	46132	43241
2009	42757	47260	43827
2010	43389	48291	44490
2011	43999	49348	45248
2012	44645	50400	45864
2013		51508	46620
2014		52709	47479
2015			47824
2016			48127

Average Compound Growth Rates			
Forecast Period	1992-12	1994-14	1996-16
	2.08	2.31	1.64



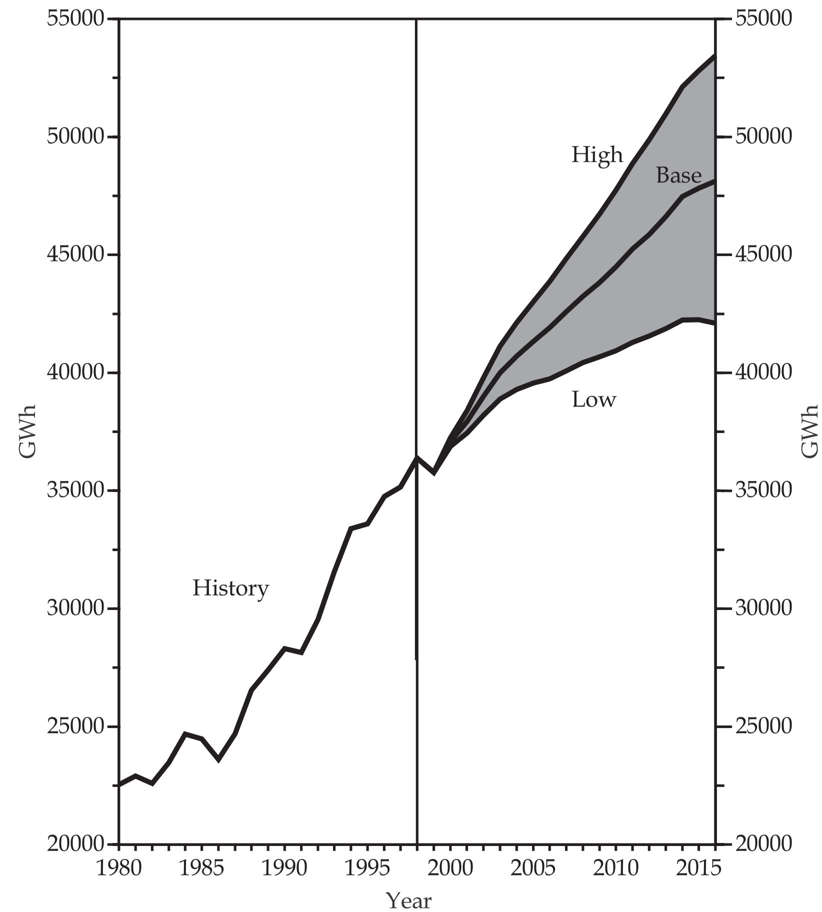
Notes: The shaded numbers in the table are historical values. (For an explanation on how SUFG arrives at these numbers, see Appendix H.)

FIGURE 7-4

Indiana Industrial Energy Sales by Scenario in GWh

Year	Base	Low	High
1996	34755	34755	34755
1997	35158	35158	35158
1998	36376	36376	36376
1999	35776	35768	35782
2000	37079	36882	37247
2001	37940	37442	38399
2002	38998	38195	39782
2003	40004	38882	41127
2004	40703	39295	42131
2005	41332	39566	43013
2006	41914	39739	43860
2007	42587	40082	44842
2008	43241	40431	45779
2009	43827	40676	46725
2010	44490	40940	47755
2011	45248	41281	48872
2012	45864	41555	49877
2013	46620	41870	50973
2014	47479	42239	52126
2015	47824	42246	52801
2016	48127	42098	53445

Average Compound Growth Rates (%)			
Selected Periods	Base	Low	High
1982-85	3.48	3.48	3.48
1985-90	2.26	2.26	2.26
1990-95	2.93	2.93	2.93
1995-00	1.31	1.24	1.41
2000-05	1.53	1.53	1.57
2005-10	1.43	1.19	1.53
2010-14	1.70	1.59	1.78
1994-14	1.46	1.36	1.54



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

FIGURE 7-5

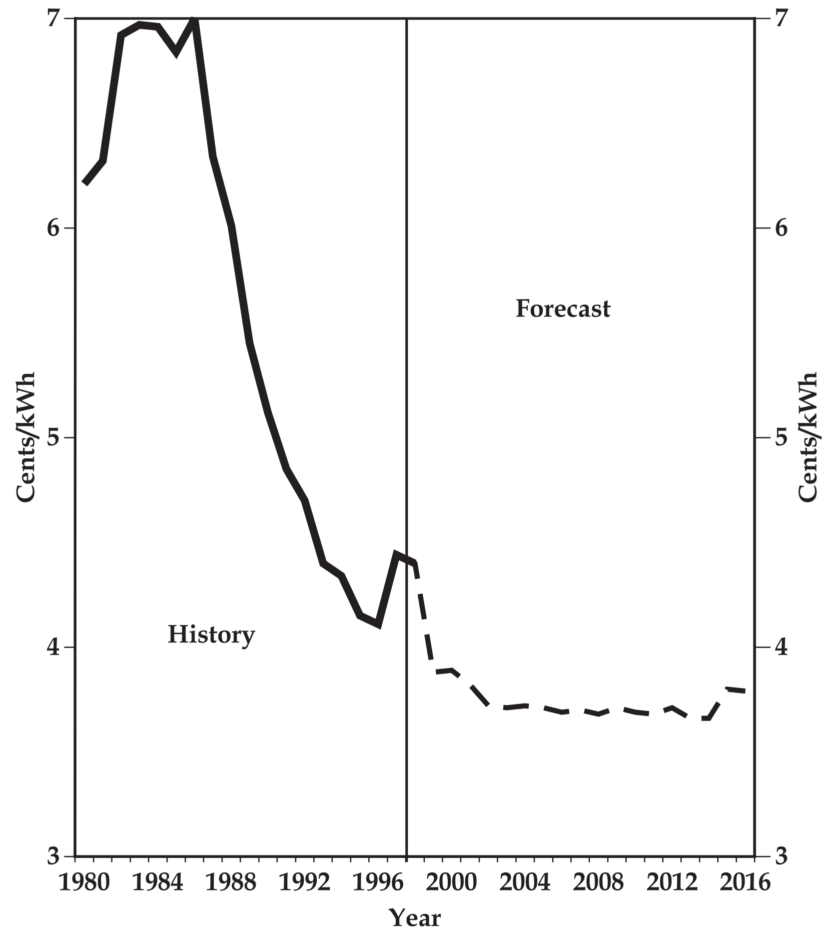
Indiana Industrial Base Real Price Projections (in 1996 Dollars)

Year	Real Price
1980	6.21
1981	6.32
1982	6.92
1983	6.97
1984	6.96
1985	6.84
1986	7.00
1987	6.34
1988	6.01
1989	5.45
1990	5.12
1991	4.85
1992	4.70
1993	4.40
1994	4.34
1995	4.15
1996	4.11
1997	4.44
1998	4.40

Year	Real Price
1999	3.88
2000	3.89
2001	3.82
2002	3.72
2003	3.71
2004	3.72
2005	3.71
2006	3.69
2007	3.70
2008	3.68
2009	3.71
2010	3.69
2011	3.68
2012	3.71
2013	3.66
2014	3.66
2015	3.80
2016	3.79

Average Compound Growth Rates

Forecast Period	(%)
1980-85	1.93
1985-90	-5.62
1990-96	-3.59
1996-00	-1.37
2000-16	-0.17
1996-16	-0.41



Energy-Weighted Average for Five IOUs

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

CHAPTER 8

INDIANA'S DEMAND-SIDE MANAGEMENT PROGRAMS

Overview

This chapter provides a general description of Indiana's demand-side management (DSM) programs and summarizes their impacts on summer peak demand and annual energy requirements. SUFG adopted utility estimates for DSM program impacts and costs that were contained in their integrated resource plans and/or load forecasts. SUFG's methodology for modeling DSM impacts is described in Appendix E.

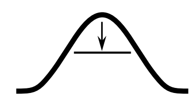
DSM is any utility-sponsored program *designed to influence customer usage in ways that produce desired changes in a utility's load shape, i.e., changes in the time pattern and/or magnitude of a utility's load* (see Figure 8-1).

The combined impact of a utility's various DSM programs can significantly impact system demand. These

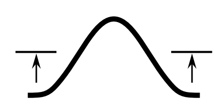
FIGURE 8-1

Load Shape Objectives

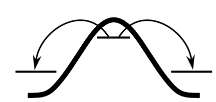
PEAK CLIPPING, or the reduction of the system peak loads, embodies one of the classic forms of load management. Peak clipping is generally considered as the reduction of peak load by using direct load control. Direct load control is most commonly practiced by direct utility control of customers' appliances. While many utilities consider this as a means to reduce peaking capacity or capacity purchases and consider control only during the most probable days of system peak, direct load control can be used to reduce operating cost and dependence on critical fuels by economic dispatch.



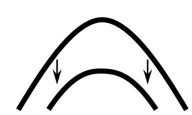
VALLEY FILLING is the second classic form of load management. Valley filling encompasses building off-peak loads. This may be particularly desirable where the long-run incremental cost is less than the average price of electricity. Adding properly priced off-peak load under those circumstances decreases the average price. Valley filling can be accomplished in several ways, one of the most popular of which is new thermal energy storage (water heating and/or space heating) that displaces loads served by fossil fuels.



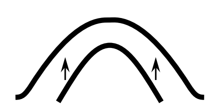
LOAD SHIFTING is the last classic form of load management. This involves shifting load from on-peak to off-peak periods. Popular applications include use of storage water heating, storage space heating, coolness storage, and customer load shift. In this case, the load shift from storage devices involves displacing what would have been conventional appliances served by electricity.



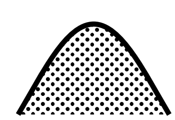
STRATEGIC CONSERVATION is the load shape change that results from utility-stimulated programs directed at end use consumption. Not nromally considered load management, the change reflects a modification of the load shape involving a reduction in sales as well as a change in the pattern of use. In employing energy conservation, the utility planner must consider what conservation actions would occur naturally and then evaluate the cost-effectiveness of possible intended utility programs to accelerate or stimulate those actions. Examples include weatherization and appliance efficiency improvement.



STRATEGIC LOAD GROWTH is the load shape change that refers to a general increase in sales beyond the valley filling described previously. Load growth may involve increased market share of loads that are, or can be served by competing fuels, as well as area development. In the future, load growth may include electrification. Electrification is the term currently being employed to describe the new emerging electric technologies surrounding electric vehicles, industrial process heating, and automation. These have a potential for increasing the electric energy intensity of the U.S. industrial sector. This rise in intensity may be motivated by reduction in the use of fossil fuels and raw materials resulting in improved overall productivity.



FLEXIBLE LOAD SHAPE is a concept related to reliability, a planning constraint. Once the anticipated load shape, including demand-side activities, is forecast over the corporate planning horizon, the power supply planner studies the final optimum supply-side options. Among the many criteria he uses is reliability. Load shape can be flexible -- if customers are presented with options as to the variations in quality of service that they are willing to allow in exchange for various incentives. The programs involved can be variations of interruptible or curtailable load; concepts of pooled, integrated energy management systems; or individual customer load control devices offering service constraints.



*Adapted from Clark W. Gellings, highlights of a speech presented to the 1982 Executive Symposium of EEI Customer Service and Marketing Personnel.

programs can have diverse impacts on the company, such as:

- changing the characteristics of the daily demand profile;
- modifying the operation of generators;
- impacting generator emissions;
- deferring the need for future generating capacity;
- lowering energy service costs to program participants; and
- changing electric rates.

Utility Programs

Much like the electric industry itself, there is considerable uncertainty regarding the future of many DSM programs. Since this forecast has been prepared for the current regulatory environment, SUFG has used information on DSM programs that the utilities provided in their IRP filings. Brief descriptions of various types of programs are contained in Table 8-1. The diversity of program offerings reflects differing utility characteristics, strategic objectives, marketing strategies and perceptions of program cost-effectiveness.

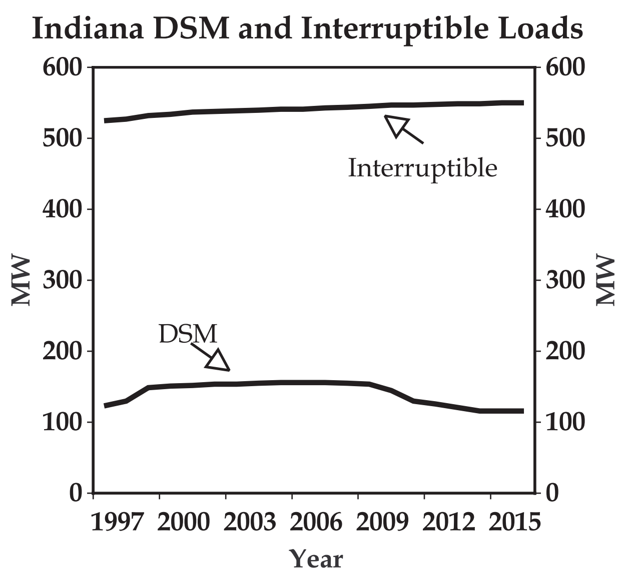
Another method that a utility might use to alter its load shape is the use of interruptible rates. An interruptible rate provides electricity at a lower price to the customer (usually a large industrial or commercial customer). In return, the utility has the option to interrupt the power supplied to the customer when certain conditions are met.

Primary DSM Program Impacts

This forecast estimates that DSM programs have reduced 1996 Indiana peak demand by about 120 MW, or slightly under one percent. DSM impacts are then projected to grow to around 150 MW by 2000 and then remain fairly constant for the next decade (see Figure 8-2). Approximately 520 MW, or about three percent of the current Indiana peak demand, are classified as interruptible.

These DSM impacts are substantially lower than those shown in SUFG's previous forecast. Those projected impacts ranged from approximately 200 MW

FIGURE 8-2



in 1994 to nearly 950 MW in 2014. The reduction in DSM is a result of utilities scaling back both the number of DSM programs and the projected impacts of the remaining programs. The projection of interruptible load has increased slightly from the previous forecast, which was approximately 500 MW.

With a few notable exceptions, utilities have not actively encouraged DSM because they were not cost effective. In many cases, the DSM programs were not dispatchable and may have reduced sales but had little effect on the costs that were incurred by the utility. The lack of broad customer acceptance of DSM is a result of low incentives (because the incentives were based on the low avoided costs of the utility) to encourage customers to reduce their use. Even for DSM programs that were targeted at reducing electrical use during peak periods, the underlying average-cost based rate structure understated the cost of providing electricity during those peak hours. In a competitive market, since the prices (directly or indirectly) will be based on marginal costs, the real value of DSM will be more accurately reflected. In a truly competitive environment, it is also reasonable to expect that power suppliers will offer a variety of pricing options that may include DSM to help both the customers and the power supplier secure more predictable and lower cost power.

TABLE 8-1

Description of DSM Programs

Residential Programs	
Refrigeration	Provide incentives (rebates) for the purchase of a higher than standard efficiency refrigerator, or provide services for the removal, disposal and recycling of an operating second refrigerator or freezer.
Air Conditioning/ Space Heating	Designed to increase the likelihood of purchasing more efficient air conditioners, increasing the market penetration of heat pumps, providing incentives for installing direct load control devices on air conditioners, or providing incentives to improve home insulation.
Lighting	Offer incentives (rebates) to purchase compact fluorescent lights and fixtures and replace standard incandescent bulbs and fixtures.
Water Heating Programs	Designed to offer (1) rebates to install jackets and low-flow, shower heads or high efficiency water heaters, (2) direct load control of water heaters, and/or (3) water heating storage for load shifting.
Comprehensive Building	Offer technical and financial assistance to builders and architects to incorporate new energy efficient technologies into new building construction, energy audits to customers and incentives (rebates) to incorporate energy saving technologies recommended.
Time of Day Rates	Offer time of day pricing to encourage residential customers to shift usage to off-peak periods.
Commercial Programs	
Refrigeration	Provide an incentive (rebate) to replace existing compressors and motors with high efficiency models.
Commercial Heat/Vent/AC	Offer incentives (rebates): (1) to replace existing fan and pump motors with high efficiency units, (2) for installing commercial office building and retail building cool storage systems, or (3) to install office building economizer controls.
Lighting	Provide incentives (rebates) to upgrade existing fluorescent bulbs and fixtures with high efficiency lights and electronic ballast.
Comprehensive Building	Offer (1) time of day rates, (2) technical and financial assistance to builders and architects to incorporate new energy efficient technologies into new building construction, and (3) energy audits to customers and incentives (rebates) to incorporate energy saving technologies recommended.
Stand-by Generator	Provide an incentive (rebate) to customers to use stand-by generation during peak demand periods.
Water Heater	Provide a water heater wrap and installation through an independent contractor.
Time of Day Rates	Offer time of day pricing to encourage commercial customers to shift their load to off-peak periods.
Industrial Programs	
Motor Program	Provide an incentive (rebate) to replace standard efficiency motors at time of failure with high efficiency motors.
Lighting	Provide an incentive (rebate) to purchase standard fluorescent bulbs and ballast with high efficiency fluorescent bulbs and electronic ballast.
Interruptible Rates	Designed for industrial customers so the utility may interrupt service during utility need.
Comprehensive Building	Includes energy audits and various efficiency improvements, motor programs and industrial water heater programs. Utilities that implement this program are effectively combining other programs which are listed separately.
Time of Day Rates	Offer time of day pricing to encourage industrial customers to shift their load to off peak periods.
Stand-by Generator	Provide an incentive (rebate) to customers to use stand-by generation during peak demand periods.

CHAPTER 9
SUFG'S COMPETITIVE PRICE PROJECTION MODELS

Introduction

SUFG began development of its first competitive pricing model in 1995 and presented these results in the 1996 forecast. Since then improvements have been ongoing. SUFG's May 1998 interim report featured an improved version of the first model and with this report, yet another enhanced version is introduced.

Results from each version of the model have become increasingly more reliable due to two factors:

- a better understanding of the structure of the emerging competitive power industry as more states move to allow competition; and
- a developing consensus regarding the elements that should be present in any model of price determination in an industry.

Even though these factors tend to reduce forecast error, they are both partially offset by a deterioration in the data bases supporting these models. This is because utilities are becoming increasingly unwilling to share reliable cost data that, they fear, may be used against them as former partners turn into competitors.

Short-Run Forecasts Under Perfect Competition

The 1996 forecast, the first SUFG forecast to attempt to predict what Indiana electricity prices might be if competition were allowed in the generation sector, was based on a short-run model with the following characteristics:

- Generation prices were determined each hour by an Eastern Interconnection power exchange where each of 7047 generating units bid in their estimated short-run marginal cost of operation to meet estimated hourly market demand.
- Hourly prices were set at market clearing levels, i.e., set at the cost of the most expensive unit dispatched to meet demand in the hour.

The net effect of these two assumptions is that in the short run, competition *works*, which means that no seller or buyer has sufficient market power to influence the market price. In short, participants are price takers. Each will bid in their supply to maximize their profit and if the unknown price is a fixed parameter, suppliers will bid in their resources at marginal cost. To continue:

- The existing transmission system was assumed to be able to handle the resultant interregional flows with no congestion; power losses were, however, considered.
- Electricity flows over the network were modeled as if they were under the control of the system operator rather than obeying the physical laws that govern these flows.

With these assumptions, the competitive model predicted that:

> *...In the short run, prices would decrease to between two-thirds to three-quarters of the price projected if no restructuring took place. This short-run advantage would disappear in 10 years as increased exports of low-cost Indiana power to nearby states and Indiana's growing needs drive up the cost to Indiana ratepayers.*[1]

Results reported in SUFG's 1998 interim report were obtained by using a model that was a much better representation of reality than that used in the 1996 forecast. The model assumed that:

- Electricity flows over the network were controlled by the physical laws that gov-

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[1]State Utility Forecasting Group, *1996 Indiana Electricity Projections*, West Lafayette, IN, 1996, p. xv.

ern such flow — the so-called power flow constraints, where flows are functions of the reactances and resistances of the lines and the net power injections of all nodes in the network.

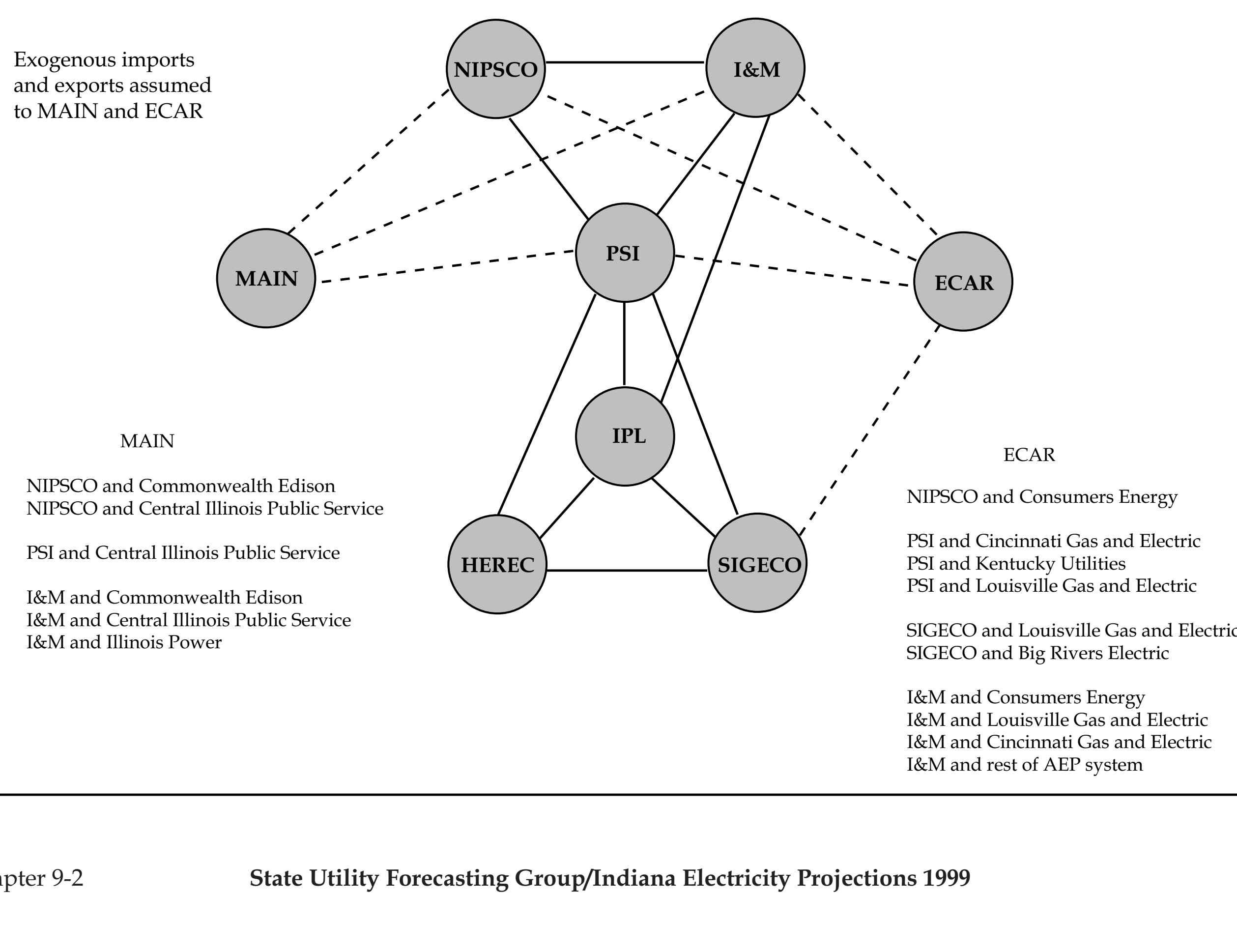
- Congestion in the network as power flows approached line limits.
- An Indiana power exchange that allowed all Indiana power to be bought and sold each hour at market clearing prices, i.e., as in the 1996 forecast, at the price of the most expensive unit dispatched to meet demand in a given hour.
- Exports to surrounding states were assumed to take place each hour at three prespecified levels: about 2000 MW, 3000 MW and 4000 MW.

The network representation of SUFG's 1998 competitive model is shown in Figure 9-1. With these assumptions, the 1998 competitive model predicted that:

Electricity prices would decline to market clearing levels, which are projected to be below the price expected if regulation continued. The extent of the decline is expected to be determined by the export market for Indiana's low-cost electricity: the higher the initial export level, the smaller the projected price

FIGURE 9- 1

Network Topology of SUFG's 1998 Competitive Model



decrease. Electricity prices could then rise in response to growing domestic and export demand, rising above the regulated price sometime in the interval 2002 to 2006, depending on the level of export demand.[2]

This year, the SUFG forecast again is based on methodology that is substantially improved over the previous model. (See Appendix G for a more thorough discussion of this model.) While maintaining the enhanced features of the 1998 model (power flow constraints, network congestion, hourly market clearing prices), the 1999 version has the capability to choose the level of Indiana imports/exports that are consistent with a *free trade* scenario for an ECAR/MAIN trading area rather than have the levels of imports/exports set outside the model.

To accomplish this, the current version of the model broadens the geographic extent of the power exchange to include all 32 utilities (as of 1994) in the ECAR/MAIN area as illustrated in Figure 9-2.

The ECAR/MAIN power exchange is assumed to receive hourly offers to buy and sell from all the generating units controlled by the 32 utilities in the diagram. The offers to sell electricity are based on each unit's variable cost, which is adopted from data available on all U.S. generating units from the Federal Energy Regulatory Commission (FERC). Hourly market clearing prices (taking into account transmission line loss) are then established and the resultant least-cost mix of generation is dispatched against the hourly load of each of the 32 demand points. Hourly demands are assumed to be inelastic and are based on a mixture of individual utility reports that estimate the magnitude and timing of their demands, FERC and EIA data, and in a few instances, data provided by NERC.

Power flows between the 32 control areas are again governed by power flow constraints as well as the transfer capabilities of the lines. ECAR/MAIN trades with Mid-Continent Area Power Pool (MAPP), Southwest Power Pool (SPP), Tennessee Valley Authority (TVA), Virginia Power (VP), Pennsylvania-Jersey-Maryland Power Pool (PJM) and Ontario Hydro (OHY). These trades take place over the dotted lines in the figure. Such trade is exogenous to the model, but this is a far less restrictive assumption than in the 1998 forecast where exogenous trade represented roughly 11.5 percent of Indiana peak demand for the base scenario. Here, exogenous trade represents only 0.25 percent of ECAR/MAIN peak demand for the base scenario.

Once the cost minimizing patterns of trade (subject to the transmission constraints) are established within ECAR/MAIN, the resultant hourly pattern of imports and exports to and from Indiana can be calculated, as well as the hourly pattern of market clearing prices Indiana rate payers can expect to be charged for generation services. (Technically, these hourly prices are the calculated additional system cost/MW at each demand point if demand at that point were to increase slightly.)

Hourly prices for each of the 32 demand points (including the six points in Indiana) were simulated over the 10-year planning horizon under two MAIN/ECAR export/import scenarios:

Scenario A. Net exports from ECAR/MAIN to surrounding utilities were a constant 376 MW, mostly to PJM and Virginia, as reported in the NERC 1998 Summer Assessment study.

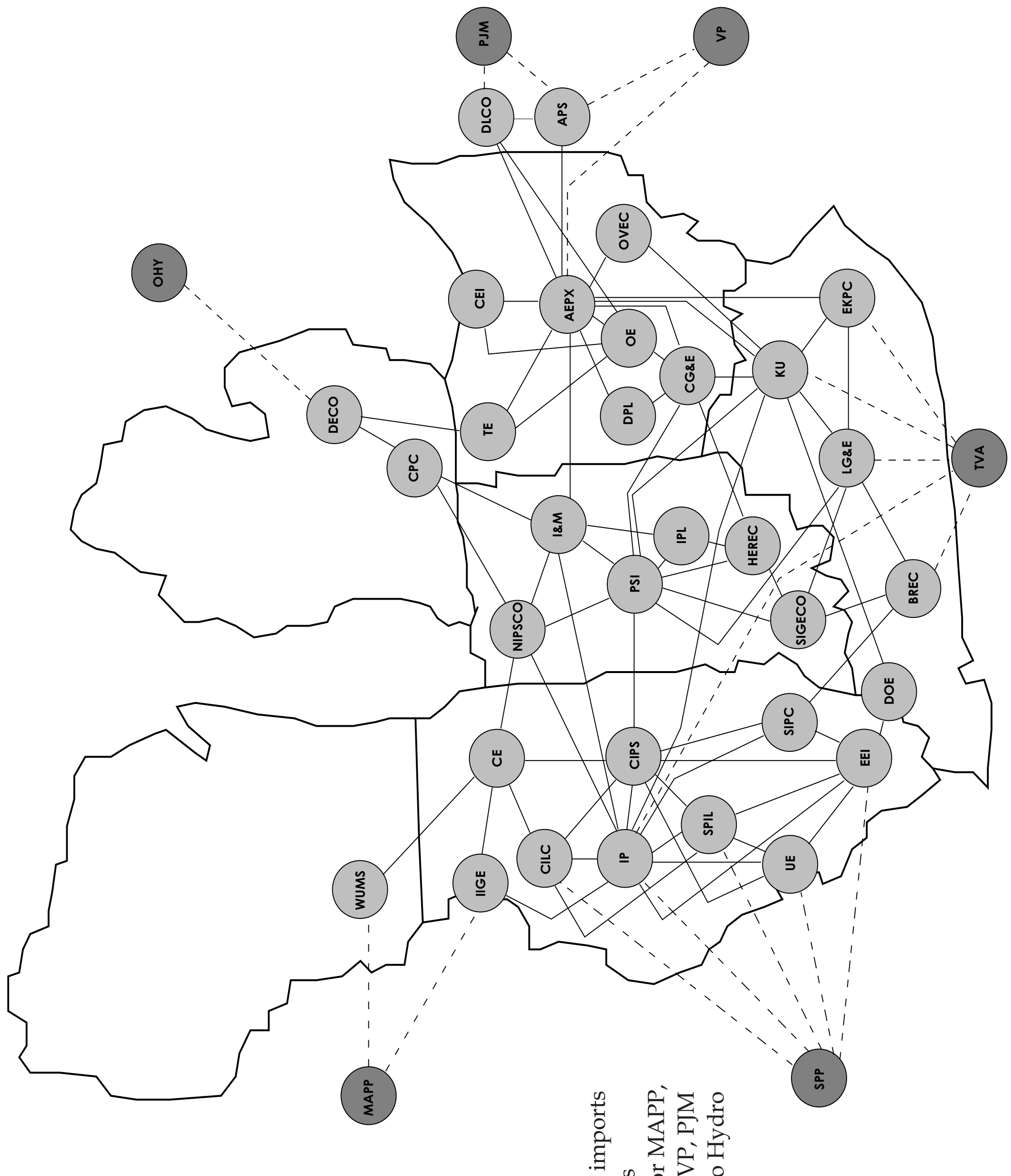
Scenario B. Net exports from ECAR/MAIN to surrounding utilities were a constant 5500 MW, which was set at roughly one-half of the maximum transmission capacity available, as reported by NERC.

For each scenario, time varying hourly production and marginal costs of the type displayed in Figures 9-3

[2]State Utility Forecasting Group, *The Projected Impact of Restructuring on Indiana Electricity Prices: An Interim Report*, West Lafayette, IN, 1998, p. v.

FIGURE 9-2

Network Topology of SUFG's 1999 Competitive Model



Exogenous imports and exports assumed for MAPP, SPP, TVA, VP, PJM and Ontario Hydro and 9-4 were obtained for each of the 32 utilities. Those displayed happen to be for one of Indiana's five IOUs; thus, they represent a utility's projected generation schedule for a sample period of time and the hourly pattern of market clearing prices for the sale of generation services by that utility. The hourly production values presented in Figure 9-3 have been normalized to protect the anonymity of the utility.

Thus, Figure 9-3 shows the MW production levels for one of the Indiana IOUs if that utility's generating units were dispatched as part of an ECAR/MAIN wide power exchange. Every hour, the power exchange dispatched the aggregate ECAR/MAIN generating units against the aggregate ECAR/MAIN demand to minimize total system generating cost subject to the power flow constraints and associated line losses. The sample hourly pattern of generation is seen in Figure 9-3.

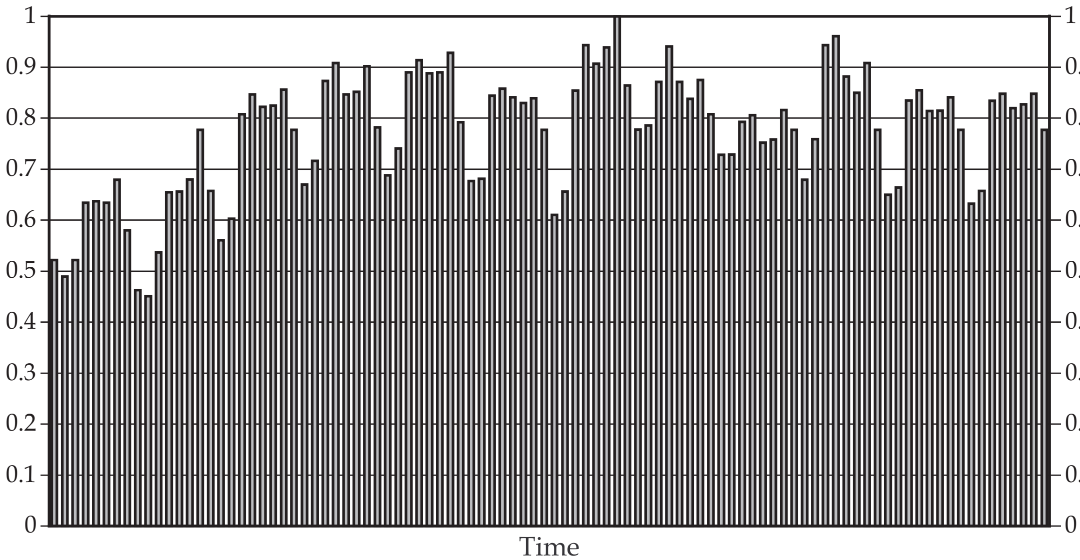
The marginal cost time pattern for the representative Indiana utility for the same sample period is shown in Figure 9-4. These marginal costs represent what the utility should charge electricity consumers on an hourly basis if it was agreed that consumers should pay for the electricity generation services they used based on the actual systemwide cost for meeting their demand. The figure illustrates a fact now well known to those who buy and sell electricity in the wholesale trading markets — prices during off-peak hours can be very low, about $18.50 per MWh (generation cost only), and over $90.00 per MWh during peak hours.

The prices, converted to an energy-weighted yearly average price, form the basis of the Indiana price projections for the two scenarios contained in Figure 9-5. The average price that is shown for each is obtained by a two-step process:

Step #1: Calculate the consumption energy-weighted yearly average price for all Indiana ratepayers by weighting each Indiana utility's time varying hourly marginal costs by hourly consumption at that cost.

FIGURE 9-3

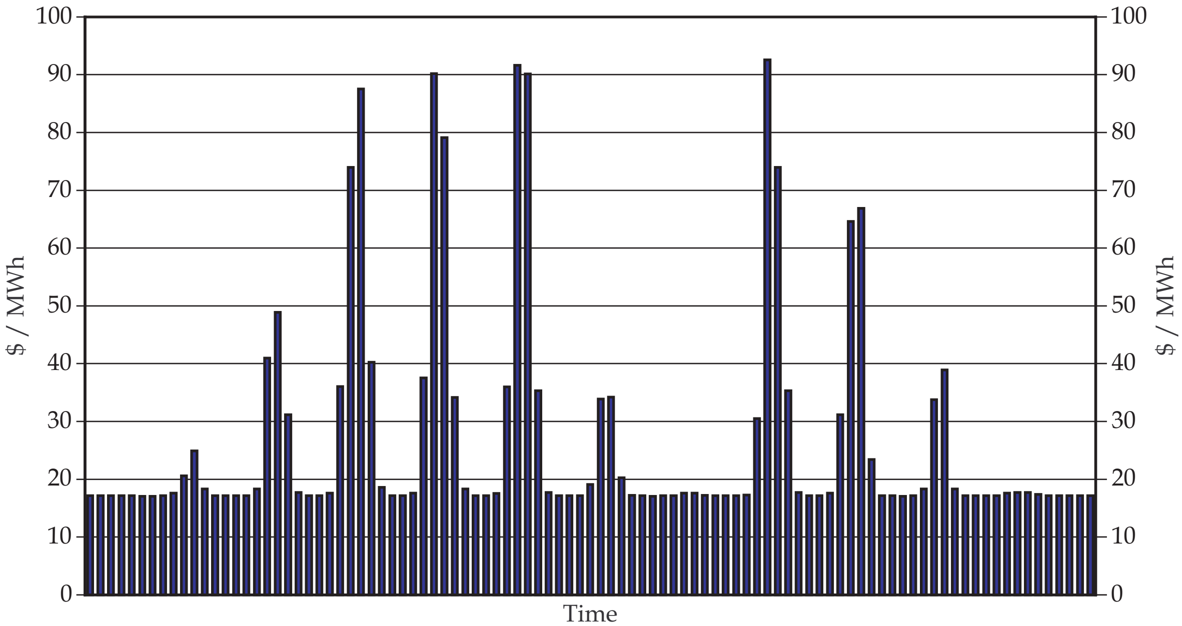
An Example of Production Levels for an Indiana Utility (Normalized)



Note: Each observation represents three hours of a 12-day sample period.

FIGURE 9-4

An Example of Marginal Costs for an Indiana Utility



Note: Each observation represents three hours of a 12-day sample period.

***Step* #2**: Add to this yearly average price a mark-up to cover the cost per MWh of the transmission and distribution system (taken from SUFG's regulated price projection) plus an estimate of the costs of ancillary services (load following, stability control, etc.).

As in the previous forecasts, all trajectories of the price of Indiana power eventually rise to the estimated long-run cost of electricity and then flatten out. (The small variations in the long-run price are due to variations in the allowed transmission/distribution adders, which are taken from the regulated model.)

The logic of this treatment is straightforward. As demand grows in Indiana and elsewhere in the ECAR/MAIN system, the yearly average price will continue to climb until price increases attract the attention of investors. These investors will construct new generating units whenever the price trajectory indicates they would obtain a return on their investment commensurate with the risk they attach to the enterprise.

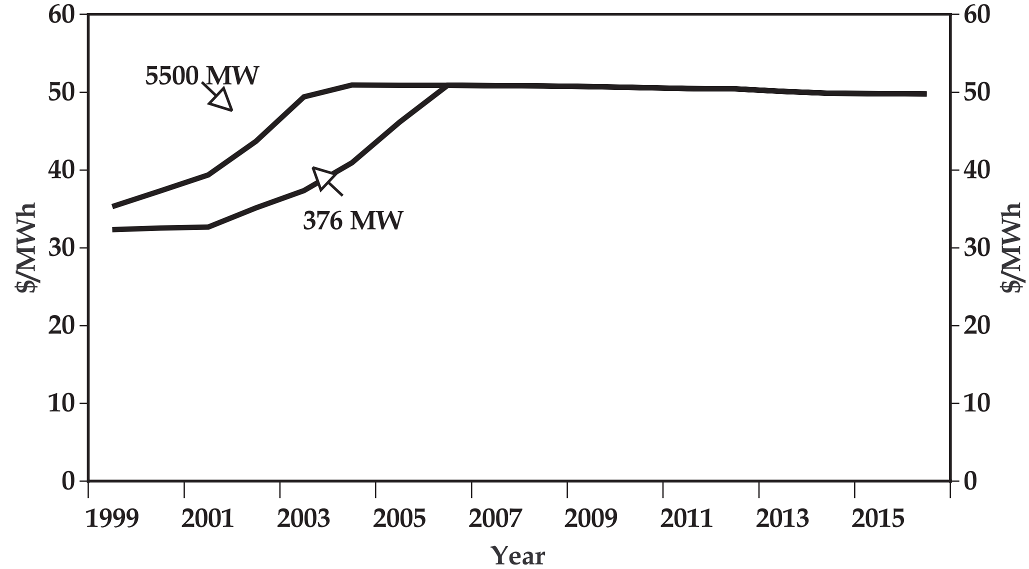
The SUFG model makes the simplifying assumption that their entry into the market is triggered when the rising short-run market clearing yearly average price reaches the estimated long-run cost of electricity. As explained below, the current SUFG forecast of the long-run generating cost of electricity, assuming the market is opened up to competition *and competition works*, is $39 per MWh.

Thus, in Figure 9-5, the trajectory of expected Indiana prices, if competition works, levels out at about 5 cents per kWh (the sum of the 3.9 cents per kWh long-run cost of generation plus the transmission/distribution/ancillary service adder).

What is the pattern of Indiana exports/imports that result from this approach? Figure 9-6 shows the time varying pattern of such trade for 1999 for Scenario A with 376 MW exports from ECAR/MAIN to neigh-

FIGURE 9-5

Indiana Yearly Energy-Weighted Average Prices for Competitive Scenarios (1996 Dollars)



boring utilities.

Several important observations need to be made regarding Figure 9-6. First, Indiana both exports *and* imports power. Although it is not intuitive from the figure, exports take place during ECAR/MAIN peak demand periods while imports take place during off-peak periods. Thus, what the model tells the analyst is that during off-peak (night, off-peak day use) hours, it is cheaper for Indiana utilities to import power from other regions since the avoided cost of Indiana generators during such periods is greater than the marginal cost of imported electricity.

Exactly the opposite is true during peak demand periods. At these times in the ECAR/MAIN system, it appears that the marginal costs of increased generation within Indiana falls below the avoided cost of utilities outside Indiana. The out-of-state utilities then purchase energy from Indiana instead of using their own higher cost generation, resulting in the export "spikes" shown in Figure 9-6.

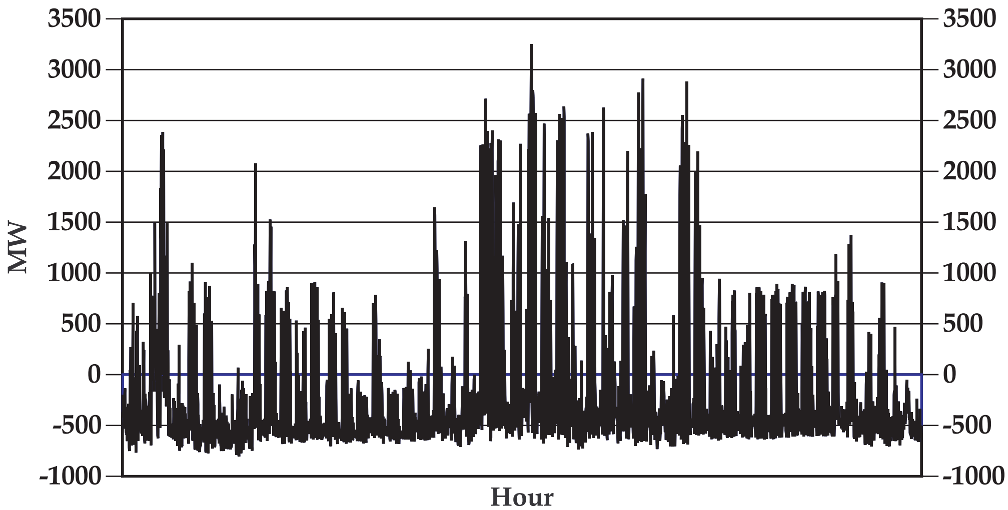
If the hourly sum over the year of all imports and exports shown in Figure 9-6 were calculated, Indiana would import an average of 152 MW per hour over the year 1999. That number decreases over the forecast horizon. This means that Indiana will become a net exporter in years later than 1999.

This result directly contradicts the assumption of a constant export demand for Indiana power made in the 1998 interim report, again emphasizing the extraordinary amount of uncertainty surrounding any forecasts of market behavior with deregulation.

In 1998, SUFG's best estimate was that Indiana's

FIGURE 9-6

Indiana Net Power Exchange in 1999
Under Perfect Competition



Note: Hours are for each hour of the year 1999.

low-cost (out of pocket) power would be able to compete effectively against other producers power costs all times of the day, season and year; hence, the assumption of a constant net export stream leaving Indiana.

SUFG's most recent analysis suggests that this will not be the case; rather, Indiana will both import and export power depending on the time of day.

This result is certainly good news for Indiana stockholders since the value of their *export crop* — peak power — is certainly greater than any revenues lost due to the import of cheap off-peak power. The impact of all this on Indiana ratepayers is reflected only in the price they were expected to pay for electricity as shown in Figure 9-5. Any gains/losses from trade will be felt by both the producers and consumers who bear the risk in this marketplace.

Forecasting Prices in Imperfect Markets

Previously, SUFG's forecasts of likely prices with a deregulated generation sector were all based on the assumption that efficient competition *works*. In this scenario, markets in economist's jargon are *perfect* -- no single buyer or seller can influence the price and all consider themselves as price takers rather than price makers. In that situation, all sellers bid a price equal to the marginal cost of all their available power, withholding none from the marketplace.

This section focuses on the issues that arise when producers or consumers feel they *can* exert power over the market in such a way that market-clearing prices are influenced. When this occurs, the industry departs from a perfectly competitive market structure and becomes imperfect. This is especially true when only a few large producers dominate the market. This raises the possibility that producers will create an artificial scarcity of electricity that drive prices well above marginal costs. (Chapter 10 raises the important policy issue regarding whether or not prices rising above marginal costs is clear cut evidence of market imperfections: the conclusion reached is that both perfect *and* imperfect markets can have periods when prices rise above marginal costs.) This concept, frequently termed market gaming, results in imperfect competition.[3] Since this scenario is as likely an outcome of electricity deregulation as is the perfectly competitive scenario, it is important that models exist that can accurately quantify market power and its impact on prices. It is far better to have the ability to model the strategy of a producer rather than its exact production characteristics.[4] However, no single model exists that can accurately measure all of these impacts.

Examples of real world departures of electricity prices from marginal cost abound. The difficulty comes from separating those caused by the correct functioning of markets from those caused by shortages that are artificially induced by dominant suppliers withholding production capacity.

Apparently, electricity suppliers in England and Wales have been exercising their market power since their markets were deregulated in 1990.[5] In 1991, for example, a 95-MW load-following plant that normally bid only £25 per MWh (about 4 cents/kWh), bid £120 per MWh with a minimum generation level of 95 MW during “constrained on” periods.[6]

Other countries are also concerned with market gaming and market power. Competition in the wholesale generation market in the Australian Electric Power Industry is limited to the eight major generation plants in New South Wales and Victoria.[7] The Australia Competition and Consumer Commission oversees the Code of Conduct governing how the national electric market works. In the New South Wales Code, the Commission denied the release of detailed trading information (i.e., bid prices) to market participants in the belief that this would make it difficult for tacit collusion in bidding to occur. However, market participants felt that they were being hindered in monitoring the actions of others to ensure that gaming and collusion did not take place. On November 23, 1997, the spot price hit a record of $3200 per MWh in Victoria due to transmission outages, generation shortages and high temperatures.[8] In South America, there has also been strong evidence of market gaming to raise the market clearing prices.[9,10]

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[3]Walter Nicholson, *Microeconomic Theory -- Basic Principles and Extensions*, 5th edition, The Dryden Press, 1998.

[4]S. Borenstein, J. Bushnell,and C.R. Knittel, *Comments on the Use of Computer Models for Merger Analysis in the Electricity Industry*, FERC Docket No. PL98-6-000, 1998.

[5]D.M. Newbery, "Power Markets and Market Power," *Energy Journal*, V. 16, No. 3, 1995.

[6]G. Backus, "Moving to Competitive Utility Markets Parallels with the British Experience," *Power Value*, March/April, 1997.

[7]Dennis Ray, *Electric Power Industry Restructuring in Australia: Lessons from Down-Under.* Paper #20, prepared for the National Regulatory Research Institute, NRRI 97-07.

[8]How Could Australian Pool Prices Hit $3,200/MWh?" *EEnergy Informer*, February 1988.

[9]V.J. Fryling, "Deal Closing Internationalist -- An Interview with the President and Chief Operating Officer, CMS Energy," *The Electricity Journal*, January/February, 1998.

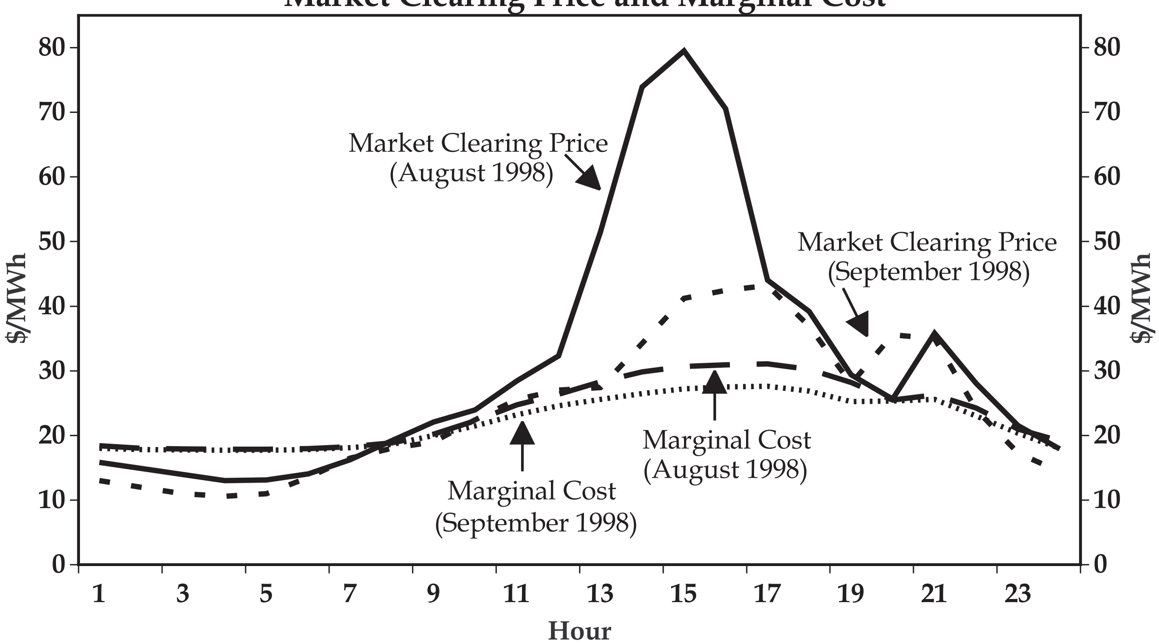
[10]H. Rudnick and R. Raineri, "Transmission Pricing in South America," *Utilities Policy*, V. 6, No. 3, September 1997.

The market power issue has caused vigorous debate in the U.S. as the electric industry moves toward competition. In late June 1998, wholesale electricity prices reached $7,000/MWh in the Midwest.[11] In the newly formulated California independent system operator,[12] replacement power prices were approximately $5,000/MWh in early July 1998 and settled at $9,999/MWh on July 17, 1998. Potential market power abuses have caught the attention of the FERC, state regulatory commissions and consumer groups. Some groups in Michigan have even called for abandoning deregulation altogether because of their concerns over market power abuses.[13]

Figure 9-7 shows that electricity markets can have either the characteristics of perfect or imperfect markets, depending on the time of day. During off-peak hours, when there are many generating units bidding for demands, market prices may be competitive and reflect marginal costs. However, during peak periods, when only a few units are available for additional production, prices will very likely depart from marginal costs as demanders scramble to outbid each other for the scarce remaining supply.

FIGURE 9-7

PJM Data: Energy-Weighted Average Market Clearing Price and Marginal Cost



[11] *The Energy Report*, "Western Resources Scolds FERC Chairman for Inaction on Price Spikes," July 27, 1998.

[12] *Megawatt Daily*, "Houston Industries Fights CAL-ISO to Seek Relief," July 13, 1998.

[13] *Electric Utility Weekly*, "In Major Reversal, Michigan Industries Call for Abandoning Deregulation," September 1998.

Figure 9-7 is a plot of average prices paid for electricity hour by hour during August 1998 by members of the PJM power exchange and statistical estimates of the average marginal cost to produce this electricity — again, hour by hour.

Average market clearing prices range below estimated average marginal cost from 1:00 a.m. to 7:00 a.m., then rise rapidly to almost three times estimated marginal cost during the peak period before falling rapidly to near marginal cost, except for the 9:00 p.m. secondary peak period.

Figure 9-7 illustrates that:

1. Market clearing prices can be below apparent marginal costs. Occasionally, the market clearing prices are observed to be zero. This occurred in PJM, California and Australia in 1998 and may be due to the following:
   - Excess generation capacity during this period would cause the producers to refrain from bidding high prices for fear of their generators not being dispatched.
   - There are physical constraints (i.e., long start-up times and slow ramp-up rates for large coal and nuclear plants) that require units to be bid in at or near zero marginal cost.
2. Market clearing prices are much higher than marginal costs during high peak hours. The reason for this is due to there being more capacity in use during this time period; therefore, reserve margins are tighter and producers have more potential to maximize their profits by bidding higher prices. If there was a shortage, the last producer with capacity would act as a monopolist by bidding a price just below their estimate of what the most needy consumer would be willing to pay.

The marginal costs are simulated by using PJM plant cost data from the EIA. Forced outages for each plant is also simulated by using the data from Stoll.[14] Figure 9-8 shows similar data collected for the California Power Exchange (CAL-PX). Figures 9-7 and 9-8 show similar patterns: market clearing prices below marginal costs from hours 1:00 a.m. to approximately 8:00 a.m. and above market clearing price during peak hours. The Australian deregulated electricity market also exhibits similar relationships.

In summary, the evidence seems to clearly indicate that while price forecasts based on marginal costs are useful indicators of how well competition is working, they should be augmented with forecasts that can take into account the possibility of market power determining prices, at least during peak periods.

Imperfect Competition Models

Economists have developed many models of price behavior for imperfect markets. To give the reader a better understanding of some of these concepts, a few of the major models are summarized below.

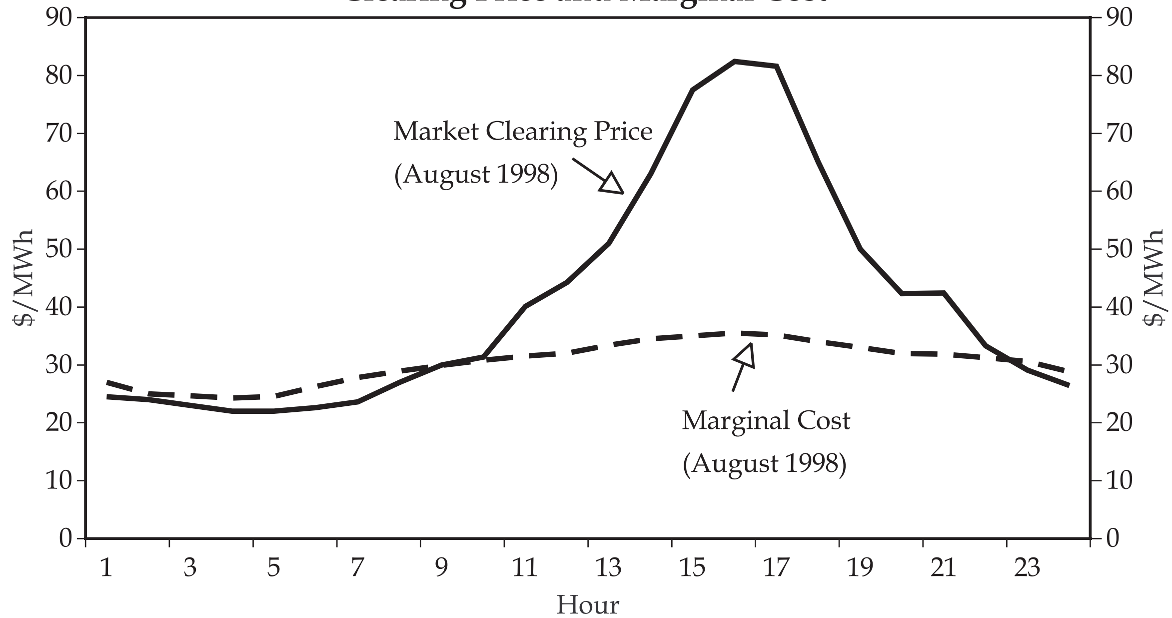
A Single Supplier — The Monopoly Case

This is the case where only one producer controls the entire market and there are many buyers. Here, the monopolist maximizes profits by restricting output until marginal revenue equals marginal cost. The monopolist recognizes that by withholding product from the market, purchasers would bid up the price on the remaining quantity supplied high enough to more than offset any reduction in revenue caused by

[14]Harry G. Stoll, *Least-Cost Utility Planning*, John Wiley & Sons Inc., 1989.

FIGURE 9-8

CAL-PX Data: Energy-Weighted Average Market Clearing Price and Marginal Cost



withholding output. This withholding process continues until the marginal benefits of withholding an additional unit just equals the marginal cost of withholding an additional unit, i.e., profits are maximized.

In reality, however, it is doubtful that a perfect monopoly exists in any deregulated electricity market. A more likely case might be one in which multiple producers collude (act like a monopoly) to restrict output and maximize their joint profits. As Shubik[15] points out, this would involve side payments if the marginal costs of the producers are not similar. Based on the electricity market price observations, there is no general support for the assumption of market collusion since one cannot then explain why prices are close to marginal cost during low demand periods. However, during very high peak demand periods, when capacity margins are very tight, a few producers that have uncommitted capacity may behave as monopolists by collusion.

Even though it is doubtful that absolute monopolies exist in the supply of electricity, the case remains of interest since it sets an upper limit on what the price trajectories might be in the often cited "doomsday scenario" -- what if a regulated monopoly is replaced with an unregulated one.

Few Suppliers -- Competition Among the Few

For years, economists have been building models describing likely outcomes when there are a few competitors -- so-called imperfect competition models. The literature contains several variants, most dealing with what type of strategic behavior the few (usually two) competitors engage in, i.e., how do they assume others will react to their market strategies?

[15]Martin Shubik, *Strategy and Market Structure*, John Wiley & Sons, Inc., 1959.

The Cournot Equilibrium. This model[16,17] assumes each competitor expects the other will not alter its behavior in the face of changes in its competitive strategies, i.e., "If I lower my bid quantity, I don't expect my competitor to alter their bid quantity." This assumption allows the calculation of a steady state price/output decision for each of the two players.

The Shackleberg Equilibrium. Some progress[18] has been made in embedding leader/follower behavior in optimization models. Here, the leader, a dominant player in the electricity supply side of the market would explicitly take into account the expected response of the smaller players when it makes its profit maximizing decision on how much to withhold from the market. On the other hand, the smaller players take as a given the decisions of the dominant supplier.

Gaming Models. Finally, gaming models, especially Nash Bargaining, have been used to model the strategies of profit maximizing producers. Different market results have been produced under assumptions of both cooperative and non-cooperative gaming. For example, in the study by Bai, Shahidehpour and Ramesh[19] where Nash gaming is used, the least-cost results are presented because demand is fixed and cooperative gaming is assumed. Non-cooperative Nash gaming has also been used to simulate the behavior of producers.[20] In this case, the producers did not exchange cost information and bidding strategies but allowed only imperfect information to be gathered. Under this scenario producers will be forced to speculate about market conditions. As a result, the solution may change constantly since there is no guarantee that producers will operate under the same assumptions.

These gaming models fail to account for the large price variations witnessed in electricity markets since they try to maximize the profit of producers in a static sense (i.e., they do not consider the physical constraints of the generation plants such as start-up costs, minimum on- and off-line time, etc.).

SUFG'S Approach

Conjectural variation and gaming models assume a specific demand curve at a specific time. This has been very difficult to duplicate in practice since many demand curves must take into account varying price levels, weather (temperature and humidity) and days of the week, including holidays. Additionally, existing studies on demand functions all estimate demand elasticity based on a single price level, such as 6 cents/kWh or a few limited price levels. The elasticities of a

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[16] Walter Nicholson, *Microeconomic Theory -- Basic Principles and Extensions*, 5th edition, The Dryden Press, 1998.

[17] D. Brennan and J. Melanie, "Market Power and Australian Power Market," *Energy Economics*, 20(1998), p. 121-133.

[18] S. Borenstein, J. Bushnell and C.R. Knittel, *Comments on the Use of Computer Models for Merger Analysis in the Electricity Industry*, FERC Docket No. PL98-6-000, 1998.

[19] X. Bai, S.M. Shahidehpour, V.C. Ramesh, "Transmission Analysis by Nash Game Method," *IEEE Trans. on Power Systems* 12, No. 3, August 1997, p. 1046.

[20] R.W. Ferrero, J.F. Rivera and S.M. Shahidehpour, "Application of Games with Incomplete Information for Pricing Electricity in Deregulated Power Pools," *IEEE Trans. on Power Systems*, V.3, No. 1, February 1998, p. 184-189.

customer class should be estimated across different price levels, ranging from a few cents per kWh to a few dollars per kWh. In this case, an elasticity function will probably be too complex to express in a closed mathematical form. Even if a given demand function has a constant elasticity, the solutions from different models could still widely vary and none of these models can produce prices that are below marginal costs. Note that in reality, a bid demand function might not be close to a true demand function, just as a producer does not always bid at marginal cost.

Due to the above-mentioned technical difficulties and the inadequacy of the existing models for this difficult class of problems, it seems appropriate to develop an empirical model and use market data to estimate the necessary parameters. The major assumption is that the collective behavior of the multiple producers and consumers can be estimated based on the data from existing markets. To do this, SUFG built an equivalent elasticity model that measures the combined effect of competitive behavior of the producers and the consumer's response to prices. This is a general mark-up or mark-down model.

Since SUFG has already estimated year by year prices that would be expected if perfect competition were to develop, the mark-up model provides an easy method to estimate the prices for imperfect competition: simply add to each estimated price the price divided by the elasticity estimate.

To do this, an estimate of the equivalent demand elasticity needs to be obtained. This can be achieved by the following equation:

$$E_{Qp}(t) = \frac{\overline{p(t,Q)}}{\overline{p(t,Q)} - MC(t,Q_j)}$$

where $\overline{p(t,Q)}$ is the clearing price observation for an electricity market at time t with a demand Q, $MC(t,Q_j)$ is the projected marginal cost of the most expensive unit at (t,Q_j) and $E_{Qp}(t)$ is the modified or equivalent elasticity of electricity consumption. Not only can it be used to predict price mark-ups, but also price markdowns in a competitive market. Thus, it can be used to predict market prices for all possible cases.

Since $\overline{p(t,Q)}$ is observable from market data, $MC(t,Q_j)$ is either observable or can be projected from existing generation data. $E_{Qp}(t)$ can then be estimated statistically.

Note that estimation of marginal cost at a specific time t would depend on different factors, i.e., temperature, humidity, plant outages and the producer's gaming behavior (withholding capacity or not). The gaming behavior is most difficult to estimate. Fortunately, the equivalent elasticities for different times include some expected estimations of gaming behavior. The first two factors can be derived by existing techniques.

For short-term estimation (a few hours to a few days ahead), weather estimation is very important to yield accurate price estimations. For mid-term to long-term estimation, it is a common practice to assume that the weather in the future is the same as in the past for the same period. For example, it can be assumed that next year's summer weather will be the same as this year or an average of the past several years.

Table 9-1 uses the equation and data taken from the CAL-PX to estimate the equivalent demand elasticities that are consistent with the data. The hourly market clearing prices and demands are from the CAL-PX. The hourly marginal costs are simulated as described above.

The weighted average values of the equivalent elasticity of the different hours listed in Table 9-1 are from the CAL-PX data of August and early September, 1998.

The equivalent elasticities estimated from CAL-PX data may have to be modified to fit the situation in a *test* market. However, using the data from Table 9-1 for estimating prices in winter and summer periods

TABLE 9-1

Estimated Equivalent Elasticities

Hour	1	2	3	4	5	6	7	8	9	10	11	12
E_{Qp}	-4.69	-3.98	-4.28	-4.51	-4.40	-5.12	-7.20	-5.25	-4.40	-3.91	-2.69	-2.43
Hour	13	14	15	16	17	18	19	20	21	22	23	24
E_{Qp}	-2.15	-1.84	-1.64	-11.59	-1.60	-1.80	-2.19	-2.57	-2.55	-3.59	-4.61	-4.78

and assuming marginal cost pricing for the rest of the year, the hourly energy-weighted average price is about $23.67/MWh for *wholesale power* in this test market without considering ancillary services and taxes (test forecast for 1999 with real price as of 1994). This number is about $6.50/MWh higher than the hourly energy-weighted average marginal cost for the same market. The percentage difference is about 30 percent.

Conclusion

There is a substantial amount of work that remains to be done before this methodology can be used with the well developed and tested perfectly competitive and continued regulation approaches used in this and previous forecasts.

Nonetheless, the situation the model simulates — a market approaching the competitive market off-peak and approaching the imperfect market on-peak — is certainly a more likely scenario than the assumption of perfect competition throughout the daily and seasonal cycle. SUFG plans to develop methods of measuring the equivalent elasticity for the midwest market and to develop more precise methods of determining which hours, and to what extent, should be treated as hours where imperfect, rather than perfect, models should be utilized.

Long-Run Forecasts

Summary of the 1999 Estimate

As in previous forecasts, the method used to develop the long-run cost of generation under restructuring as shown in Tables 9-2 and 9-3 is based on two steps:

- develop estimates of the long-run cost of generation from each of three types of units — combustion turbines, combined cycle, and pulverized coal plants; and
- weight each of these costs by their expected share of kWh generation and sum.

In the analysis, the additional cost reductions resulting from competition assumed in the August 1997 EIA study of the impacts of competition -- 15 percent reductions in O&M costs, construction costs per kW and heat rates[21] -- are applied to the costs for the combustion turbines, combined cycle and pulverized coal units described previously.

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[21]Energy Information Administration, *Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities: A Preliminary Analysis through 2015*, Department of Energy, DOE/EIA-0614, September 1997, Executive Summary, Figure ES2. Projected Regional Retail Electricity Prices under Regulation and Competition, 2000, p. 7.

TABLE 9-2			
New Generation Costs Under Restructuring			
	Combustion Turbines	**Combined Cycle Units**	**Pulverized Coal Units**
Capital Cost ($/kW)	281	417	978
Capacity Factor (%)	10	40	80
Fixed O&M ($/kW)	11.70	30.91	28.90
Variable O&M ($/MWh)	0.29	0.47	1.78
Heat Rate (BTU/kWh)	9588	6239	8330
Fuel Cost ($/mmBTU)	2.50	2.50	1
Energy Weight	0.020	0.185	0.795

TABLE 9-3				
Long-Run Costs Under Restructuring (Cents/kWh)				
	Combustion Turbines	**Combined Cycle Units**	**Pulverized Coal Units**	**Total**
Average Capital Recovery	0.020*5.123	0.185*1.902	0.795*2.232	2.229
Average Fixed O&M	0.020*1.336	0.185*0.882	0.795*0.412	0.518
Average Variable O&M	0.020*0.029	0.185*0.047	0.795*0.178	0.151
Average Fuel Cost	0.020*2.397	0.185*1.560	0.795*0.833	0.999
Long-Run Average Cost				3.896

Note: The values in the last column represent the energy-weighted cost for all types of generators. They are found by multiplying the cost by the energy weight for each generator type and summing across all types.

Partially offsetting these cost reductions will be an increased cost of capital in a competitive environment. The move from regulation to competition will mean an increase in risk to investors in new generation. To attain the necessary capital to the riskier investment, greater rewards will have to be achievable. SUFG has used a 16 percent capital recovery factor for the long-run cost of capital under competition, compared to the equivalent of a 12 percent capital recovery factor under regulation.

Applying these changes to new generation costs result in the costs under competition shown in Table 9-2. The long-run marginal cost of generation under competition, 3.9 cents/kWh, is derived in Table 9-3. To determine the long-run retail price of electricity approximately 1.1 cents/kWh must be added to account for transmission and distribution costs. These costs are developed from SUFG's continued regulation model.

Comparison with Previous Restructuring Long-Run Costs

As shown in Table 9-4, this year's estimate of the long-run price of electricity, if generation were opened up to competition, is compared with estimates SUFG made in 1996 and 1998.

As indicated in the table, SUFG's projections are all in the range of 4.4 cents to 5.0 cents per kWh. The changes in the forecast are attributable to several factors:

- Upward revisions in the projected capital costs for the equipment. At the time of the 1996 and 1998 forecasts, few plants were on the drawing board; hence, estimates of capital costs were not precise. To remedy this, SUFG commissioned a study by SEPRIL Services to estimate the likely construction costs for the three plant types. The 1999 estimate uses these costs rather than the earlier ones.
- Downward revisions in the fuel cost, as a combination of improved heat rates and constant, or reduced forecasts of fuel prices decreased this component.

In retrospect, SUFG 's 1998 assumption -- that equipment costs contained in the then current EPRI TAG would be halved with competition -- was probably unrealistic. While equipment costs have declined and will probably continue to decline as cost minimization replaces the rate base as the driving force for projects, the 1998 projection now appears unlikely.

The 1999 forecast resembles most closely SUFG's initial estimate made in 1996 — the long-run real (1996 dollars) cost of electricity for Indiana ratepayers, if competition were allowed, is expected to be in the neighborhood of 5.0 cents/kWh.

TABLE 9-4

SUFG Forecasts of the Long-Run Cost of Electricity under Restructuring (1996, 1998 and 1999)

Category	1996 (1994 $)	1998 (1994 $)	1999 (1996 $)
Fuel	1.19	1.06	1.00
Variable O&M	0.22	0.19	0.15
Fixed O&M	0.39	0.34	0.52
Capital Cost	2.05	1.77	2.23
Transmission	0.26	0.26	0.29
Distribution	0.47	0.47	0.48
General	0.27	0.27	0.32
Total	**4.84**	**4.36**	**4.99**

CHAPTER10
FIVE ISSUES OF IMPORTANCE TO INDIANA POLICYMAKERS

Will Indiana Surrender Its Price Advantage if It Restructures?

As shown in Table 10-1, of the four states that are contiguous to Indiana, only Kentucky has lower average regulated rates. It is no coincidence that the other three states -- Ohio, Michigan and Illinois -- have moved toward competition in the electricity generating business much faster than Indiana and Kentucky. States with relatively high regulated electricity rates *expect* competition to result in lower prices. This assumption, however, brings up some valid concerns for low-cost states, such as Indiana:

1. Will prices increase or decrease as a result of restructuring?
2. Will the state surrender a relative economic advantage (lower electricity prices) to its neighbors by restructuring?

While the first of these concerns is addressed in Chapter 9, this section attempts to address the second.

Some have argued that a low-cost state is better off by having businesses locate in that state in order to gain access to that power rather than becoming an electricity exporter. By restructuring, the state allows customers from nearby states to enjoy the benefit of the low-cost electricity without having to physically locate there; thus, depriving the state of potential economic benefits. One counter argument is that the prices in other states will be reduced as those states restructure, so the regulated state will lose its relative economic advantage anyway. Thus, the state that does nothing will lose potential electricity exports without bringing in new customers.

To determine the impact of the restructuring decision on the relative prices between states, the prices of both Indiana and its neighbors were determined both with and without restructuring in Indiana. This entails two scenarios:

TABLE 10-1

Revenue and Ranking for Indiana and Surrounding States

State	Ranking	Revenue (Cents/kWh)
Kentucky	2	4.03
Indiana	8	5.23
Ohio	28	6.30
Michigan	35	7.10
Illinois	39	7.69

Source: Energy Information Administration, *State Electricity Profiles*, "Table A1. Miscellaneous Statistics on States with Both Utility and Nonutility Data, 1996," February 1999.

1. All states in MAIN and ECAR restructure. Free trade is allowed as described in Chapter 9.
2. All states in MAIN and ECAR, except Indiana and Kentucky, restructure. Indiana and Kentucky allow electricity to be traded across their utilities, but are neither net buyers or sellers of electricity.

Three assumptions are common to both scenarios:

- no transition periods are included;
- the long-run marginal cost is the same in all states;
- stranded cost charges are not included in the prices and
- perfect competition is assumed.

Lengthy transition periods or limited pilot programs in any of the states should keep prices closer to the regulated prices in the short term. Long-run marginal costs would vary from state to state if there were differences in fuel transportation costs or transmission and distribution costs. Stranded cost recovery would impact a customer's total bill, but may or may not impact the level of trade. Furthermore, new loads that are choosing a state in which to locate might not be subject to stranded cost recovery.

For the first scenario, the average price of electricity in Indiana, Ohio, Illinois and Michigan was determined using the competitive model. The generation charges are shown in Figure 10-1. Generation charges are provided instead of total electricity prices because SUFG does not have the capability to forecast transmission and distribution costs for other states. Under this scenario, Indiana will still have a slight advantage over Illinois, Ohio and Michigan.

For the second scenario, the average price of electricity in Indiana was determined using the regulated model. The average price of electricity in the other three states was determined using the competitive model, with Indiana and Kentucky being neither net importers or exporters. The generation charges are shown in Figure 10-2. In the short term, prices under restructuring in the neighboring states will fall below the regulated prices in Indiana.

It is apparent that much of Indiana's relative advantage in terms of low electricity prices will disappear if neighboring states restructure, even if Indiana does not. Furthermore, Indiana and Kentucky utilities would still have access to wholesale markets in other states under the second scenario. These exports would tend to push prices down in neighboring states. On the other hand, if competition in those states was imperfect, prices would be higher in the neighboring states.

Are Price Excursions Sure Signs of Market Failure?

It is important to recognize that economists distinguish between two situations where market prices can depart from marginal cost:

- Scenario A -- when individual suppliers withhold output or charge a very high price for their limited output, knowing that the exercise of their market power can increase their profit; and

FIGURE 10-1

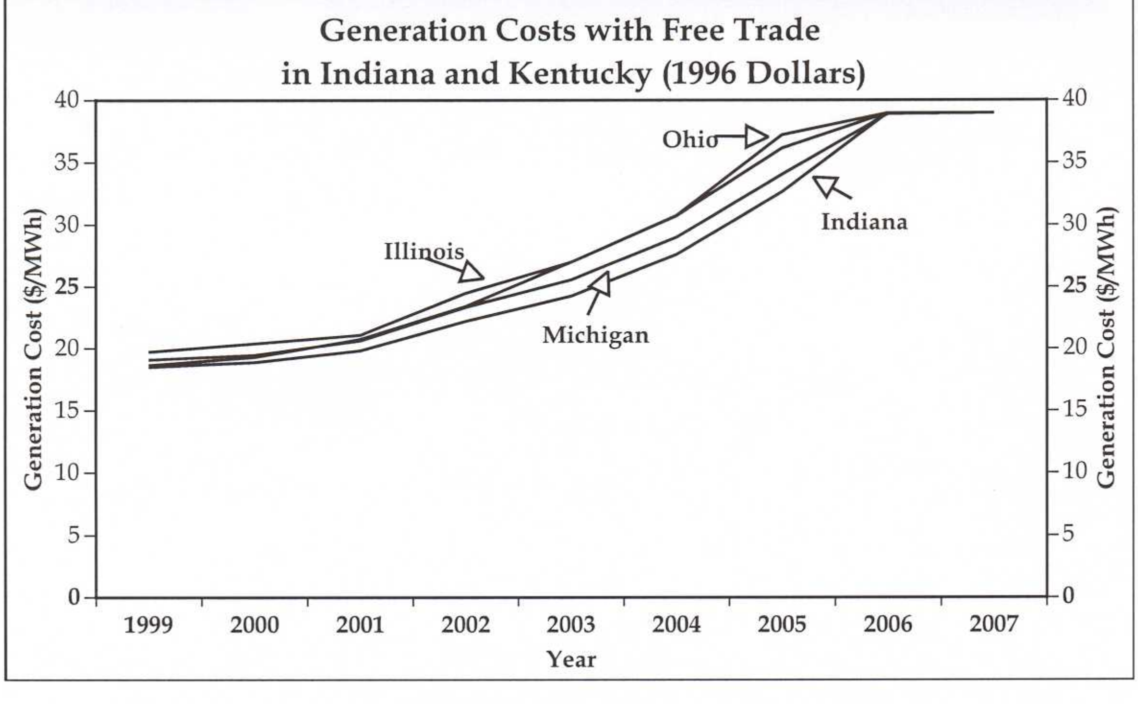
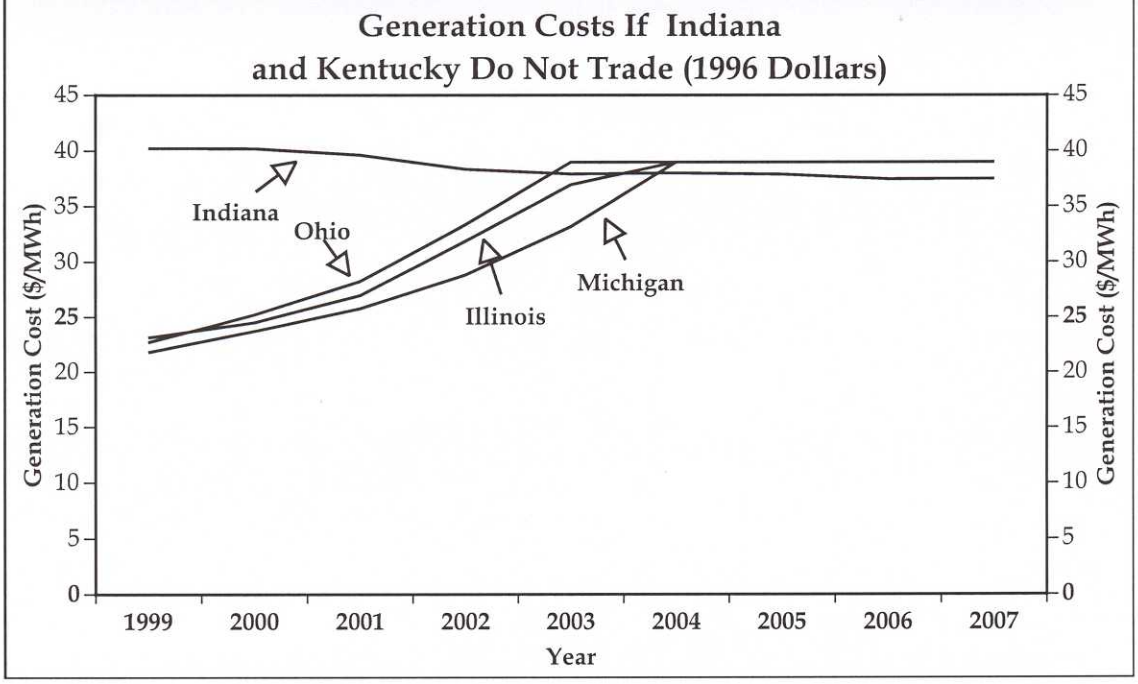


FIGURE 10-2



- Scenario B -- when individual suppliers bid into the market their output at their true marginal cost, but multiple buyers for the limited output bid up the price paid for the scarce resources. This results in the price being equal to the buyers' avoided costs, which can be well above the marginal cost. The price then reflects the true scarcity value of the capacity, not its marginal cost; there are no market failures in this case.

Figure 10-3 illustrates the two situations.

In Scenario A, suppliers bid in their true marginal costs for all their capacity, which results in the supply function "S-S" in the diagram; suppliers make available Q_c megawatts for consumption at or above the prices indicated, the prices being identical to the true marginal costs of the units bid into the market. Given the demand function "D-D," the market clearing price -- P_c in the figure -- covers MC_c, the marginal cost of the most expensive unit dispatched -- *plus* the correct scarcity P_c-MC_c.

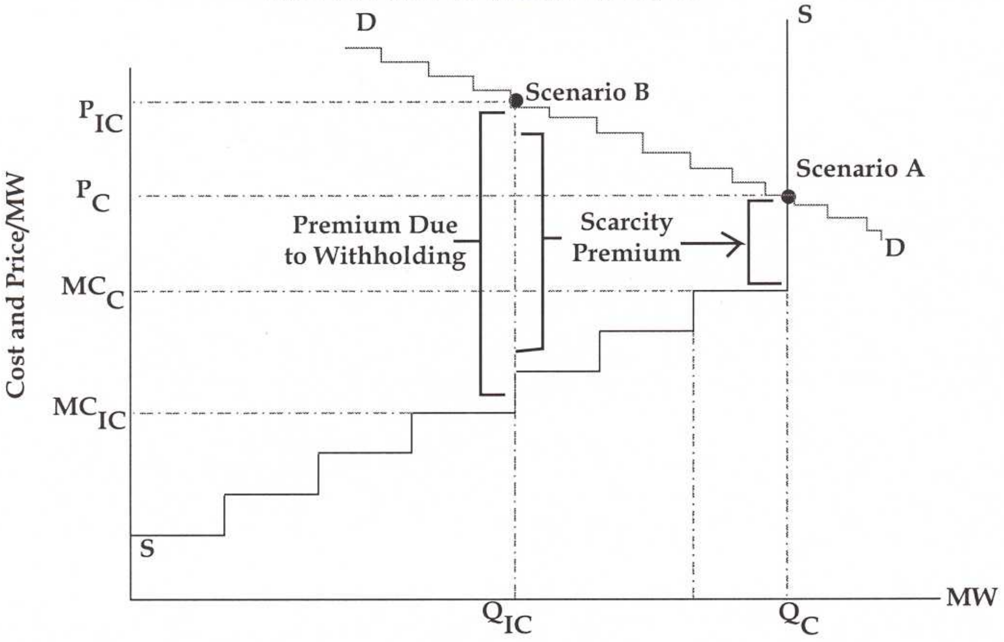
In Scenario B, suppliers with market power, knowing this market power allows them to withhold output and drive up the market price to their advantage, offer a total amount of Q_{IC} to the market that results in a market clearing price of P_{IC}. This price reflects the scarcity premium premium of Q_{IC}, not its marginal cost, MC_{IC}, on the diagram.

However, in this case, the scarcity value is higher than that which would hold in a perfect market because of supplier actions that limit production.

The regulatory implications of Scenarios A and B are quite different. In Scenario A, the market functions correctly. The price, P_C, covering both the marginal cost and the scarcity premium, is the correct market signal including, as it does, the correct scarcity premium, which should serve as the signal to new

FIGURE 10-3

Supply Behavior With and Without the Exercise of Market Power



Note: "S-S" is the hourly supply (dispatch) curve of the utilities, the cost in ascending order to sell at the indicated marginal cost plateaus. "D-D" is the demand curve for electricity at that hour, which reflects the descending buyer costs avoided by the purchase of the indicated amounts of electricity.

investors to start the construction of new generating capacity. There is no conspiracy on the part of suppliers to drive up prices; hence, no intervention is needed. Actually, if the standard mitigation measure -- price caps -- is adapted in this circumstance, incorrect long-run market signals will result and the market can be counted on to exhibit chronic price spikes of the type seen in the Midwest last year.

On the other hand, if Scenario B occurs, excess market power is being exercised and some form of regulatory intervention is called for to ensure that the correct bids are being entered into the market clearing mechanism. (Note the same result could hold if suppliers overbid their costs rather than underbid their quantities.)

To summarize:

In the absence of market power by any seller in the market, price may still exceed the marginal production cost of all facilities producing output at that time. Price above marginal production cost of all operating plants is not in itself proof of market power abuse ... (i.e., Scenario A, above). ...*However, offering power at a price above marginal production (or opportunity) cost, or failing to generate power that has a production cost below the market price, is an indication of market power abuse.*[1] (Underlining added.)

[1]Borenstein, Bushnell and Wolak, "Diagnosing Market Power in California's Deregulated Wholesale Electricity Market," February 1999 Discussion Paper, World Bank, *Energy Week 99*, Washington, D.C., April 6-7, 1999.

Regardless of the supply-side cause of any price excursion, the price should reflect the avoided cost of demanders, i.e., what they would have to pay to avoid the use of the electricity purchased. Given what is known about the cost to the final user of interrupting or withholding power under various advance notice scenarios, avoided costs are unlikely to be more than $1000 to $2000 per MWh for one hour's supply of 50 MW, indicate a major market failure on the demand side, not the supply side. Thus, the one *sure thing* learned from recent price excursions would not be that market manipulations took place, but that the current immaturity of the demand side of the spot market prevents prices paid to be a good measure of regional avoided costs. This illustrates the need for market mechanisms that allow customers better curtailment choices.

Will There Be Sufficient Capacity in the Midwest Region?

In the 1996 forecast, SUFG identified a need for approximately 1000 MW of new capacity by 2000 to maintain a 20 percent statewide reserve margin. This capacity could be obtained either by constructing new generating units or by purchasing capacity from out-of-state utilities or independent power producers. Recent capacity needs have been met by contract purchases and from spot market purchases. In this forecast, approximately 500 MW of new capacity is needed to meet a 15 percent statewide reserve margin in the summer of 2000.

Lower reserve margins are a regional phenomena rather than being isolated to Indiana. In its *Assessment of ECAR-Wide Capacity Margins 1998-2007,* ECAR projects the 1999 summer capacity margin for the ECAR region to be 8.7 percent. Furthermore, it projects capacity margins to continue falling to 6.5 percent in 2002.

The lower generation margins are believed to be a contributing factor to the high prices seen in the Midwest during the week of June 22, 1998. Unusually warm weather combined with lower reserves, unexpectedly high amounts of unavailable generation and an inability to transmit large amounts of power from outside the region to create prices as high as $7500/MW.

Perhaps as a result of the high prices, several new generation projects have been proposed in Indiana. Table 10-2 provides a list of the projects that have been publicly announced or for which petitions have been filed with the IURC. It is important to note that these facilities, if they are completed, will be under no obligation to sell their power to Indiana utilities. On the other hand, additional generating facilities will help ease the tight regional supply situation even if the power is exported to other states.

TABLE 10-2

Proposed New Generation in Indiana

Owner	MW
SIGECO (General Electric Co-Generation Facility)	42
Amoco/Whiting Refinery	550
IPL	200
AES Greenfield	400
Duke Energy Vermillion	640
Enron	500

Will Natural Gas Supplant Coal as the Primary Source of Fuel for Electric Generation?

Of the approximately 2330 MW of proposed new capacity in Indiana, 2290 MW will use natural gas as a fuel source. This trend toward increased use of natural gas is also evident on a national basis and is expected to continue. Low construction costs, along with recent improvements in efficiency, have made gas-fired technology attractive with the move toward deregulation in the electricity generation industry.

Traditionally, the low fuel cost and economies of scale associated with large coal-fired generating units have made coal an attractive option for baseload generation. While coal-fired capacity can still be competitive at high capacity factors when the unit is run at or near full capacity most of the time,[2] natural gas-fired capacity holds a clear edge at lower capacity factors. Furthermore, the lower capital costs of natural gas-fired generation are particularly attractive in a riskier, more competitive environment. Also, the threat of stricter clean air standards, particularly the nitrogen oxides (NO_x) standards being implemented by the Environmental Protection Agency (EPA), make natural gas more appealing.

The relative economics of coal- or gas-fired generation are also highly dependent upon the relative prices of these fuels. This occurs because the cost of fuel is the primary determinant of variable operating costs accounting for 75 percent or more of out-of-pocket generation costs. Thus, the choice of coal-fire versus gas-fired generation depends greatly on projected fuel costs for both coal and gas.

Presently, Indiana has a surplus of baseload capacity and a need for additional peaking capacity. Therefore, new capacity in Indiana could be expected to be primarily natural gas fired even without the threat of restructuring and tighter emissions standards.

Figure 10-4 shows that in SUFG's traditional base scenario, energy from natural gas-fired generation is predicted to increase by approximately 10 percent per year, as compared to a growth rate of 1.8 percent for all forms of generation in Indiana. Energy from coal-fired generators is predicted to increase by 1.1 percent per year.

What Will Be the Impact of NO_x Reduction Requirements?

In July 1997, the United States EPA proposed regional NO_x emissions reductions. In September 1998, EPA announced final plans for a reduction in NO_x emissions of 1.1 million tons annually in 22 states, including Indiana, and the District of Columbia.[3] This represents a 28 percent decrease in NO_x emissions. The individual states have until September 1999 to develop compliance plans with controls to be in place by 2003.

Without knowledge of the compliance plan for Indiana (specifically the requirements placed on Indiana electric utilities), SUFG cannot predict the specific impacts of utility NO_x emissions reduction requirements. In this section, some generic expected impacts are discussed. SUFG expects to provide more detailed impacts in future reports.

NO_x emissions reductions are expected to impact utility costs in three direct and two indirect ways. The cost to purchase and install new equipment needed to reduce emissions will increase the utility rate base in a manner similar to scrubber retrofits for compliance with the sulfur dioxide (SO_2) requirements of the 1992 Clean Air Act Amendments (CAAA). A second im-

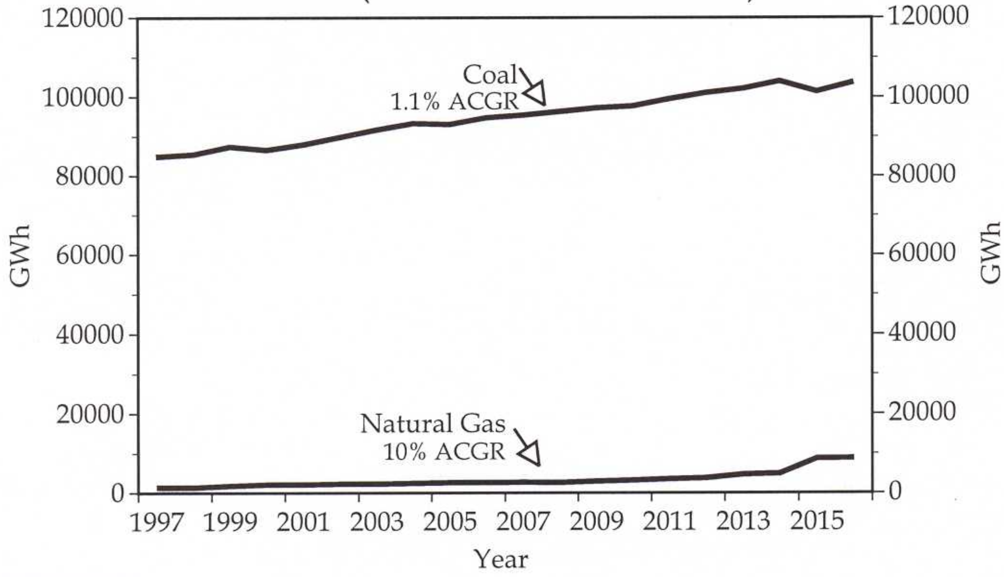
[2]SEPRIL, L.L.C., *Plant Design, Performance & Cost Comparison Study,* August 1998.

[3]In May 1999, the U.S. Court of Appeals in Washington, D.C. ruled that the proposed rules were not legal. At the time this report was issued, the status of an appeal, if any, was unknown.

pact involves any changes in the heat rates of the generating facilities. Similarly, changes in O&M expenses can be expected. An indirect impact on utility costs as a result of NO_x emission reductions result from any additional downtime for facilities being retrofitted. While the generating units are shut down, the utility will need to make up for that capacity either through the use of other, possibly more expensive generation that the utility owns or by purchasing power from others. Another indirect impact occurs because the emissions reductions make natural gas more attractive than coal for new generation decisions.

FIGURE 10-4

Energy From Coal and Natural Gas in GWh (1999 SUFG Base Scenario)



THE HOUSING MODEL

SUFG uses the ORNL housing model to project residential household growth for three types of housing—single family, multi-family and mobile homes. SUFG assumes utility service area residential customer growth rates are the same as the household growth rate derived from the Oak Ridge model. These residential customer growth rates are then input to the SUFG's residential econometric forecasting model.

The structure of the housing model is shown in Figure A-1. The primary inputs to the housing model include CEMR's projections of real personal income and the IBRC 1993 projection of county population by age group. Other inputs to the housing model include existing housing and the distribution of new construction by building type.

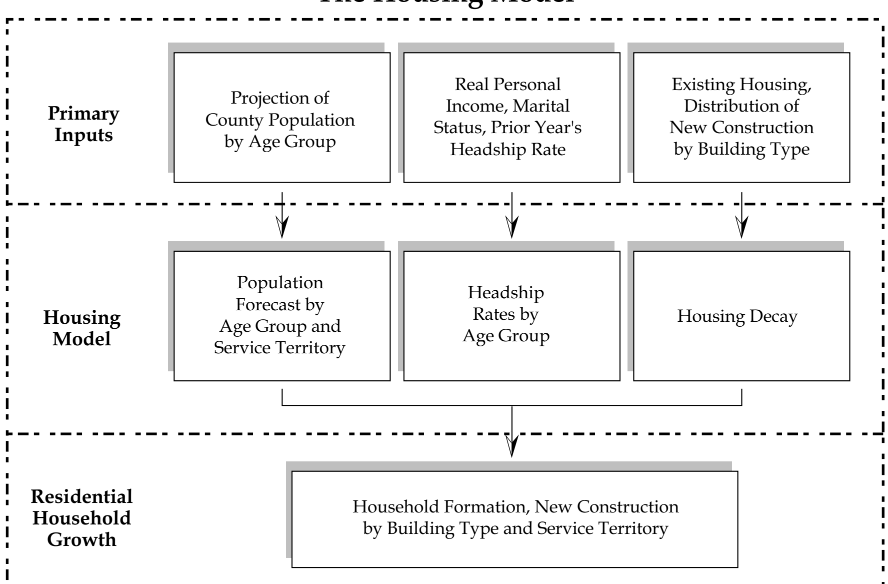
The housing model uses income growth and other factors to project headship rates, i.e., the fraction of population within each age group that is a head-of-household. Headship rates are multiplied by the population projections to yield total households. The model also calculates housing decay. The change in total households (net additions) are added to housing decay to form new construction, which is distributed among the three building types on the basis of an assumed allocation.

The main function performed by the housing model is projection of headship rates. Headship rates are assumed to be a function of age, income, marital status and the prior year's headship rate. The functional relationship is represented by a logit model. This model is calibrated to census estimates of age group specific headship rates for Indiana.

SUFG's projection of average occupants per household, the inverse of the headship rate, is shown in Figure A-2. The number of occupants per household has been declining rapidly as baby boomers have aged and their children have left home to form new households. This trend is projected to slow dramatically in the forecast period as these young adults have children.

FIGURE A-1

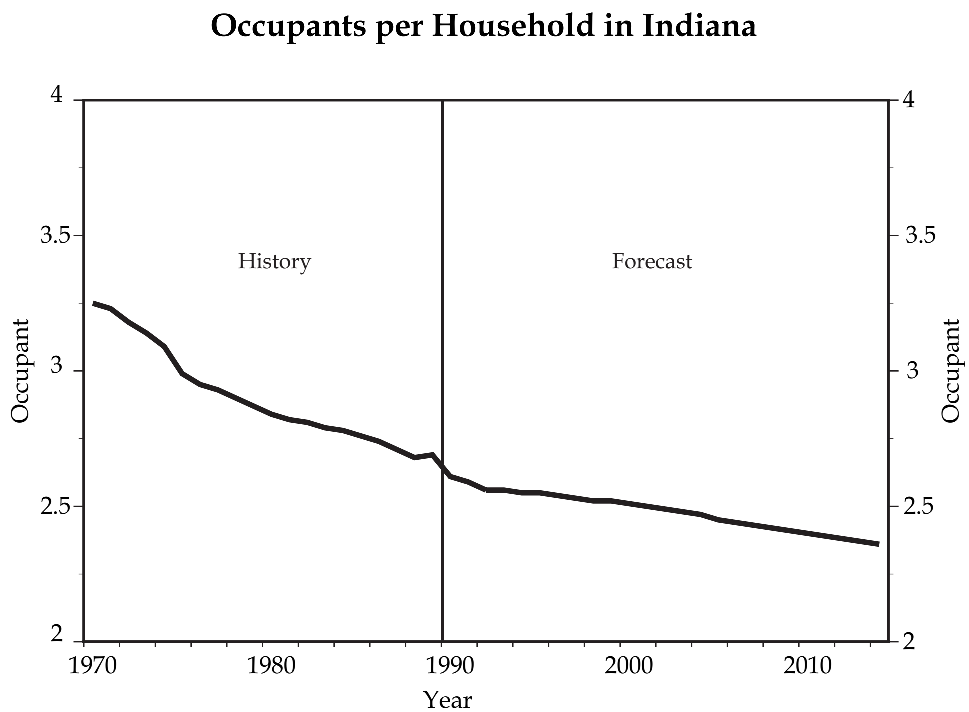
The Housing Model



HOUSING MODEL

Prior to 1993, SUFG used the housing model to project households for the state and shared them to the utility level. SUFG now directly projects residential customer growth for each of the ten utility service territories. This is done by mapping county level population data to utility areas according to the fraction of population in each county served by each utility.

FIGURE A-2



THE RESIDENTIAL MODEL

Fuel Choice Model

A logit fuel choice model, which was based on relative fuel costs and other factors, was estimated in double log form from data combined across all five Indiana IOU service areas spanning 1965-1985. The dependent variable in this model is the ratio of electricity's share of the space heating market to that of all other fuels (this expression is referred to as a logit). Market share, or penetration, is defined as the change in electric space heating customers as a fraction of net new customers. The advantages of modeling penetration rather than saturation are that penetration:

(1) captures current activity;

(2) is independent of the rate of customer growth; and

(3) exhibits greater year-to-year variation.

A logit formulation has two properties that make it particularly appropriate for modeling space heating fuel choice. First, it constrains the penetration rate to the range of 0 to 1. Second, the elasticities of the double log logit model are not fixed; they vary according to the market share. This causes penetration to move between 0 and 1 in an S-shaped (nonlinear) path. This is desirable because it is typical of how market penetration proceeds.

As noted above, the major explanatory variable in the fuel choice model is relative fuel costs. The relative fuel cost variable measures the relative operating cost of obtaining a fixed amount of delivered heat, in this case, one million Btu (1 mmBtu), from any two fuels. In other words, this variable is constructed to account for the differing heat content values and average conversion efficiencies among the various space heating fuels. The general formula for calculating the incremental cost of obtaining 1 mmBtu of delivered heat from any fuel source follows:

*Fuel Cost = ((1 mmBtu/Btu per fuel unit)/efficiency) * unit fuel price*

Thus, 1 mmBtu of delivered heat from an electric baseboard system with an efficiency of 1.0 requires 293 kWh (*(1 mmBtu/3412 Btu per kWh) / 1*). Similarly, an equivalent amount of delivered heat from a natural gas furnace with an efficiency of 65 percent requires 1.54 mmBtu (*1 mmBtu/0.65*). Multiplying by the respective fuel prices yields the relative cost measure for electricity and natural gas. An analogous measure is constructed for electricity and distillate oil.

The relative fuel cost variable captures the effect of projected changes in space heating efficiencies on fuel choices. For example, prior to the late 1980s, the efficiency of conventional natural gas heating systems averaged about 65 percent. The average efficiency of new gas space heating systems is now about 85 percent. SUFG assumes the efficiency of new gas space heating equipment will continue to improve, reaching a maximum of 95 percent by 2016 (efficiencies of 90 percent and higher are currently available). These projected improvements in gas space heating system efficiencies have the effect of increasing the relative fuel cost for electric space heating and decreasing electricity's future market share, all else being equal.

The price sensitivity of the estimated fuel choice model is indicated as follows. A 20 percent rise in the price of natural gas will increase the penetration of electric space heating from 65 percent to 77 percent. Furthermore, a similar rise in the price of distillate oil would cause electric space heating penetration to increase to only 67.5 percent. The lesser response to oil price is consistent with the relative importance of natural gas and oil in the statewide residential home heating market.

The estimated logit fuel choice model replicated actual statewide penetration rates during the historical period very well. In order to project penetration for each service area separately, this estimated model was calibrated to each service area's space heating penetration and fuel costs. Under SUFG's base case assumptions of relatively stable electricity prices and fossil fuel prices, this model projects the penetration of electric space heating to average about 30 percent for all years of the forecast period (1997-2016).

The Expenditure Share Model

An expenditure share model, denoted by *Rx*, relates the fraction of a household's total income spent on a commodity to all the factors that may affect that expenditure pattern. The most robust form of this model employs a log-log functional form where both the explanatory variables and the dependent variables are expressed as natural logarithms.

$$ln(Rx) = ln\left(\frac{P*Q}{Y}\right) = a + b\,ln\,P + c\,ln\,Y + \ldots \quad (1)$$

Equation (1) is nonlinear and allows price and income elasticities to vary with price and income levels according to the following formulae:

Price Elasticity	Income Elasticity
b-1	c+1

Furthermore, there is no a priori reason to guess what the signs of coefficients "*b*" and "*c*" might be in the Rx model. In fact, even if statistical estimation showed "*b*" and "*c*" not to be statistically different from zero, the own and cross price elasticities would be unity because the expenditure share, not physical quantity, is equal then to some constant value.

SUFG uses the expenditure share model to project average electricity consumption by non-electric heating customers. Explanatory variables include a six period distributed lag of real electricity prices, real income per household, a price index denoting the real price of household appliances and heating and cooling degree-days. This model was reestimated in 1993 with historical data through 1991. The new elasticity estimates for this model are shown in Table B-1 along with those estimated in 1987 and 1988.

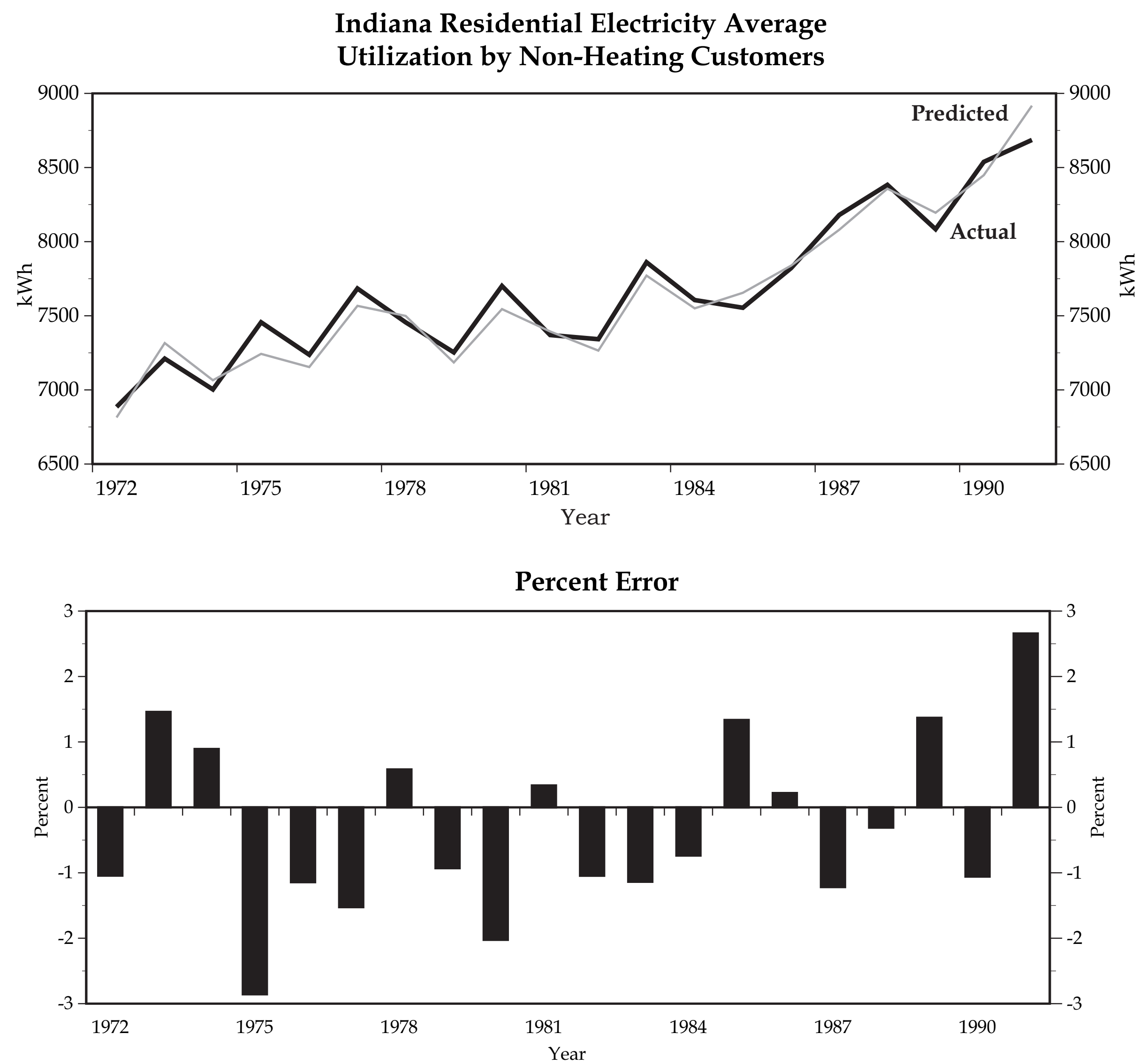
The actual and predicted values of average use by non-electric space heating customers, averaged across the five IOUs are plotted in Figure B-1 along with percentage errors in each year. The newly estimated model tracks actual experience through 1991 extremely well. Weather is responsible for the year to year swings.

TABLE B-1

Estimated Demand Elasticities for Indiana (Current and Past SUFG Estimates)

	1987	1988	1993
Own Price	-0.32	-0.37	-0.25
Household Income	0.32	0.47	0.29
Appliance Prices	-0.34	-0.42	-0.26

FIGURE B-1


Indiana Residential Electricity Average
Utilization by Non-Heating Customers
Predicted
Actual
kWh
9000
8500
8000
7500
7000
6500
1972
1975
1978
1981
1984
1987
1990
Year
Percent Error
Percent
3
2
1
0
-1
-2
-3
Year

COMMERCIAL FORECASTING MODELS

Econometric Model

The commercial sector econometric model was originally developed by SUFG staff in 1987 and reestimated in 1988 and 1994. A single ordinary demand model relating commercial sales to the various determinants of demand was estimated for each IOU (prior to 1994 this model was estimated statewide only). The unique aspect of this model is its major economic driver. This variable represents the size of the commercial sector and separates the influences of changes in the mix of buildings (with widely varying energy intensities) from price. This variable is constructed from the end-use model's simulation of building type detail. Each year the end-use model's estimate of floor space for each building type is weighted by its respective electric intensity for 1972 and summed across all building types. Thus, floor space stock growth in buildings with greater electric intensities results in greater changes in this variable than equal floor space stock growth in buildings with lesser electric intensities. This weighted floor space stock variable captures the changes in electricity use over time due to growth in commercial floor space and changes in the mix of buildings. This leaves the price variable to pick up changes in electric intensities within the various building types, i.e., the "pure" price impact.

CEDMS — Discrete Choice Microsimulation

An early extension to CEDMS replaced the ORNL methodology for simulating HVAC choices with a much simpler and better representation. CEDMS now uses discrete choice microsimulation to simulate equipment choices. This methodology is described next.

The population of commercial establishments is described by probability distributions depicting (1) operating cost expectations for each fuel-specific alternative and (2) payback requirements. An additional interfirm variation in operating hours is included for lighting choices. CEDMS develops sample firms from these population descriptions using a stratified random sampling scheme.

Instead of determining fuel and efficiency choices separately using a combination of econometric and engineering methods (where fuel shares were determined by logit models and efficiency choices were determined by "technology curves" that represented the tradeoff between efficiency gains and capital costs for each fuel and end use), CEDMS jointly determines fuel and efficiency choices. Sample firms in the model make choices from a set of discrete HVAC equipment options. Each discrete equipment option is characterized by its fuel type, energy use and cost. Each sample firm in the model evaluates all equipment options conditional upon its economic characteristics (1 and 2 above) and chooses the equipment with the lowest cost. The specific fuel and efficiency choice is stored for later calculation of building type averages. CEDMS repeats this procedure for each sample firm. The diversity of choices in CEDMS reflects the diversity among the population of commercial establishments.

The discrete choice representation incorporates many significant advantages over the technology curve representation, the most compelling of which may be the provision of a structure for easily evaluating demand-side programs. For instance, an incentive program for air-conditioning units whose efficiency exceeds some threshold can be represented by simply reducing the equipment cost of all technologies affected by the program by an amount equal to the incentive. Incorporating this program in the technology curve framework requires a re-specification and re-estimation of the technology curve.

Implementation of CEDMS for Indiana

CEDMS was originally calibrated at the statewide level and recently has been calibrated for each of the five IOUs in Indiana. These service area models are used to develop the commercial energy projections contained in this report.

SUFG's state level implementation of CEDMS is calibrated to a 1989 base year from data provided by Indiana's electric and gas utilities as well as state employment data and numerous building type-specific surveys, DOE's 1979 "Non-Residential Buildings Energy Consumption Survey." DOE's April 1992 publication, "Commercial Building Energy Consumption and Expenditures 1989," together with a California Energy Commission sponsored 1982 survey, were used to develop initial estimates of floorspace per activity measures that are multiplied by the corresponding activity level for Indiana to yield commercial floorspace estimates for Indiana. The activity measures, estimated building space per unit of activity and the resultant estimates of floorspace stock in 1989 for Indiana are shown in Table C-1 along with the adjusted building average electric intensities.

SUFG's service area calibration procedure is described below.

Calibration Steps:

1. Initial estimates of building floor space.
2. Initial estimates of energy use by building type.
3. Initial estimates of end-use saturations.
4. Space heating and air conditioning energy utilization indices (EUIs) are adjusted to normal heating and cooling degree days for each service area.
5. Final estimates of 1, 2, and 3 above are obtained through a statistical calibration procedure.

TABLE C-1

Indiana Commercial Floorspace Estimated Parameters

Building Type	1989 sqft (Million)	Activity Measure	sqft per Activity Measure	EUI (kWh/sqft)
Offices	230	Employment + Population	576.1 6.1	19.9
Restaurants	209	Employment	784.5	16.9
Retail Establishments	38	Employment	231.0	42.2
Groceries	35	Employment	492.6	51.9
Warehouses	121	Employment	656.7	7.1
Elementary Schools	111	Enrollment	104.1	8.7
Colleges	44	Enrollment	274.2	13.6
Health Care	75	Hospital Beds Nursing Home Beds	1141.1 500.0	29.7
Hotels / Motels	30	Employment	36.8	19.8
Miscellaneous	252	Total Other Buildings	0.3	8.8
Total	**1145**			**16.6**

6. Results of steps 4 and 5 are input to CEDMS and utilization elasticities are re-estimated.

Initial estimates of building floor space were constructed for each utility service territory using county level economic activity measures, e.g., employment, school enrollments and hospital and nursing home beds. These data were translated to service territories using a county to service territory mapping. Next, 2-digit SIC employment data were allocated to building types (as shown in Table C-2). These building type-specific economic activity measures were multiplied by estimates of floor space per employee for each building type, consistent with those developed by Jerry Jackson and Associates, the developer of CEDMS, for the state level model (see Table C-1). School enrollments were used for elementary and secondary school buildings and college buildings. Hospital beds were used for health care facilities.

Estimates of energy use by building type were developed for each service area. These estimates were derived from utility provided SIC-coded electricity sales data that SUFG allocated to commercial building types, utility DSM studies and state level estimates of end-use energy use per square foot of floor space (EUIs) and equipment saturations. These initial estimates of building energy use were adjusted proportionately to conform to total known commercial sales.

Little information was available on utility-specific end-use saturations. Estimates of space heat (by fuel type) and air conditioning saturations were developed from knowledge of the service territories and from information provided by the utilities. Where no other information was available, the state level end-use saturations from CEDMS were used.

Space heating and air conditioning EUIs are weather-adjusted for each service area based on different heating and cooling degree-days. According to

TABLE C-2

Mapping 2-Digit SIC Employment or Other Activity Measure to Building Type

Building Type	SIC Employment and Other Activity Measure
Offices	SICs 42-43, 60-69, 73, 33% of 80, 81, 10% of 83, 86-89, and 90-97
Restaurants	SIC 58
Retail Establishments	SICs 52-53, 55-57, 59, 72, 76
Groceries	SIC 54
Warehouses	SICs 42, 50-51
Elementary Schools	Enrollment in 1989 extrapolated via population age 5-17
Colleges	Enrollment in 1989 extrapolated via population age 18-22
Heath Care	Hospital & Nursing Home Beds in 1989 extrapolated by employment SIC 80
Hotels / Motels	SIC 70
Miscellaneous	SICs 9, 15-17, 40-41, 44-48, 71, 74, 75, 77-79, 90% of 83, 84, 86, and 89

Jerry Jackson, space heating EUIs are adjusted by 50 percent of the difference in heating degree-days. A 33 percent adjustment factor is used for cooling (based on cooling degree-days). These adjustments are less than proportional because the 65 degree-day base overstates heating and cooling loads. Thus, if a service territory had 10 percent more heating degree-days than the state average, its heating EUI equaled 105 percent of the statewide heating EUI. Similarly, if cooling degree-days were 20 percent greater, its cooling EUI equaled 106.6 percent of the statewide cooling EUI.

The initial estimates of saturations, EUIs and floor space were statistically adjusted to match total commercial sales in each service area. Each estimate was adjusted according to its standard error (judgmentally determined) and other factors. Adjustments are a function of the magnitude of the standard error and the differences between estimated sales and known control totals.

The final estimates of saturation, EUI and floor space are input to CEDMS, along with utility specific estimates for historical floor space, heating and cooling degree-days, etc. CEDMS reestimates the utilization elasticity estimates according to actual electricity sales for the calibration period.

THE INDUSTRIAL ECONOMETRIC MODEL

The full INDEED modeling system includes estimated equations for each of the 20 two-digit SIC industries covering the manufacturing sector. All but two of these models behave well when applied to Indiana data. SIC 23 (apparels) and SIC 29 (petroleum refining) are problematic and hence, not used in SUFG's system. Additionally, INDEED is not used for SIC 31 (leather) and 39 (miscellaneous industries) because macroeconomic projections are not provided by CEMR. This is not particularly troublesome at the state level since the sum of electricity use by all four of these industries is only slightly over 3 percent of the total industrial sales in the state. However, for individual utilities, petroleum refining and miscellaneous can be more of a problem. For petroleum refining, output is assumed to grow at the same rate as overall economic activity in the state and intensity is assumed to decline so that energy sales are projected to decline from current levels. For miscellaneous manufacturing, output and intensity are projected to grow at the same rates as for aggregate manufacturing. For each of the remaining 16 industries, the model projects total costs and each major input's share of total cost.

The INDEED model was originally estimated using data across states and for the nation for 1958 to 1981. National data were obtained from the Office of Business Analysis, U.S. Department of Commerce. The Census of Manufacturers and Annual Survey of Manufactures (1967, 1971 and 1974-1978) were used for state level data.

The SUFG version of the INDEED system is calibrated for Indiana using estimates of input cost shares of each industry in the state. The original calibration used data from the 1981 Annual Survey of Manufactures and was updated in 1990 using 1983 and 1984 data. Future calibration updates may be problematic as the government has ceased collecting the data on industrial energy use at this level of detail.

Because the demand for electricity is derived from the marketplace's demand for an industrial firm's output and the production function summarizes the relationship between inputs and the firm's product, the theoretical model of electricity demand begins with the firm's production function. Firms are assumed to act as though they were minimizing cost subject to producing a given level of output. From that, economic theory and some mathematical manipulation provide a model specification complete with two sorts of restrictions—those that are necessary to make the framework logically consistent and those that depend on the aggregate behavior of individual firm decision makers. INDEED simultaneously estimates the total cost of producing a given level of output (value of shipments) and the share of costs attributable to each of eight inputs. The models is designed to approximate the true cost function and more importantly, to approximate behavior toward the choice of production technologies as reflected in production input choices. Several assumptions about model specification were made.

- Functional Form - The model uses a mathematical form that is flexible and capable of approximating the true function. That mathematical form is called the trans-log and is less restrictive than other traditional specifications, i.e., Cobb-Douglas and Constant Elasticity of Substitution. In this case, flexible functional forms are thought to be better because they allow response elasticities to vary according to the level of total cost and the level of input cost shares. The fact that those same variations were themselves restricted to follow precise relationships is not often mentioned in the literature. The more important advantages of flexible forms are that they depict the most general representations of the production technology, allow for imposition and testing of a larger number of theoretical properties, and a stronger theoretical foundation makes it possible to modify the models to address new issues as they arise.

- Adjustment Time - A static model assumes that all inputs are variable and that optimal adjustments to price changes are made instantaneously. Dynamic models assume that some factors are fixed in the short run and adjustment to these factors occurs over time. The INDEED model includes a static version and several alternative dynamic specifications. Because of the difficulty of filling the data requirements for the dynamic specifications, SUFG has thus far relied only on the static formulation. However, while the equations used are static, projections are made to adjust dynamically over a period of four years by assuming that decision makers respond to a four year weighted average of industrial electric rates.
- Returns to Scale - "Constant returns to scale" implies that if each input or collection of inputs increases by X percent, then output will increase by X percent. Constant returns to scale were assumed in the INDEED model.
- Technological Change - The rate and direction of technological change are important parameters in energy forecasting models. Their direction, or trajectory, signals whether production technologies are becoming more or less electricity intensive. The rate of technological change indicates how fast this change is occurring. While technological change might be expected to respond to market prices, most empirical models have assumed its rate to be exogenous. INDEED reflects two sorts of exogenous technological change. Neutral technological change lowers total cost over time and is not biased toward any inputs. Whether or not a consistent neutral technological change existed during the historical period was estimated by including a time trend in the cost equation. Biased technological change results in increased or decreased use of one or another input. Biased technological change was captured by adding time trends to the factor share equations for each individual input.

Estimation Results: Table D-1 presents summary performance statistics (R^2 for the quantity of electricity) together with the estimated, conditional (holding the quantity of output constant) own-price elasticities. Use of these elasticities result in very close tracking of electricity use during the historical period. The estimated elasticities are fairly large, which indicates demand is responsive to input prices. Problems with petroleum refining are indicated by the very elastic estimated responses for labor and materials prices. Small changes in either of these variables result in large changes in projected electricity use.

In general, fossil fuels are more price responsive than electricity. Labor, capital and materials were estimated to be less price responsive than electricity. Electric price increases are estimated to increase expenditures on electricity for 19 of the 20 industries (inelastic demand), and also to result in greater shares of total cost for electricity. Electricity and fossil fuels are substitutes in 17 of the 20 industries (estimated cross price elasticities are shown in Table D-2). Electricity and capital are found to be complements in 15 industries. Labor is a substitute for electricity in 13 industries.

Implementation of the Model for Indiana

Data are not available to calibrate the INDEED model to individual service territories in the state. However, the state level calibrated model was used to forecast independently for each of the five IOUs. Projections of industrial electricity rates specific to each utility are used to drive each utility's forecast. Basically the same growth is assumed to hold across utilities for the other causal variables. However, besides the different forecast electric rates, forecasts of aggregate industrial electricity use vary due to the different initial mix of industrial activity in each service territory.

TABLE D-1

INDEED R^2 for Electricity Use and Own Price Elasticities

SIC	Name	R^2	Electricity	Fossil Fuel	Capital	Labor	Materials
20	Food	0.9	-0.5	-0.5	-0.6	-0.5	-0.3
21	Tobacco	0.8	-0.5	-1.7	-0.5	-0.9	-0.3
22	Textiles	0.4	-0.6	-0.8	-0.1	-0.4	-0.3
23	Apparel	0.9	-0.6	-0.6	-0.9	-0.5	-0.4
24	Wood	0.8	-0.4	-1.3	-0.2	-0.5	-0.3
25	Furniture	0.8	-0.4	-0.4	-0.6	-0.3	-0.4
26	Pulp & Paper	0.9	-0.4	-0.7	-0.3	-0.3	-0.5
27	Printing	0.9	-0.9	-0.9	-0.2	-0.3	-0.3
28	Chemicals	0.4	-0.7	-0.8	-0.1	-0.3	-0.1
29	Petroleum	0.1	-0.5	-0.6	-0.5	-2.5	-2.5
30	Rubber/Plastics	0.1	-0.3	-0.6	-0.5	-0.2	-0.3
31	Leather	0.7	-0.4	-0.7	-0.3	-0.3	-0.3
32	Stone & Clay	0.9	-0.4	-0.4	-0.4	-0.4	-0.9
33	Primary Metals	0.7	-0.9	-0.8	-0.3	-0.3	-0.6
34	Fabricated Metals	0.9	-0.6	-0.6	-0.4	-0.2	-0.6
35	Non-Electric Machinery	0.9	-0.6	-0.9	-0.4	-0.5	-0.4
36	Electric Machinery	0.9	-0.3	-0.8	-0.5	-0.3	-0.4
37	Transportation	0.7	-0.6	-0.7	-0.4	-0.3	-0.4
38	Instruments	0.7	-0.7	-0.8	-0.3	-0.1	-0.5
39	Miscellaneous	0.7	-1.1	-1.2	-0.5	-0.2	-0.3

TABLE D-2

Electricity Cross Price Elasticity

SIC	Name	Fuel	Capital	Labor	Materials
20	Food	0.5	-0.1	0.4	-0.3
21	Tobacco	-2.2	-2.3	0.6	4.4
22	Textiles	0.2	-0.6	0.5	1.4
23	Apparel	-0.0	-0.2	0.1	0.7
24	Wood	0.9	-0.1	0.3	0.5
25	Furniture	0.3	0.3	-0.8	0.6
26	Pulp and Paper	0.0	0.0	-0.1	0.5
27	Printing	0.0	-0.1	0.2	0.5
28	Chemicals	0.5	0.3	0.9	-0.9
29	Petroleum	-0.2	-1.7	-2.7	5.1
30	Rubber/Plastics	0.1	0.1	0.0	0.1
31	Leather	0.0	-0.2	0.5	0.2
32	Stone & Clay	0.2	-0.1	0.0	0.3
33	Primary Metals	0.3	0.2	-0.3	0.4
34	Fabricated Metals	0.2	-0.1	0.4	0.1
35	Non-Electric Machinery	0.3	-0.1	0.2	0.2
36	Electric Machinery	0.3	-0.1	0.4	-0.4
37	Transportation	0.2	-0.1	-0.1	0.6
38	Instruments	0.0	-0.6	-0.2	1.4
39	Miscellaneous	0.2	-0.1	-0.2	1.2

LOAD MANAGEMENT STRATEGY TESTING MODEL (LMSTM)

Model Description

LMSTM, developed by Electric Power Software, is unique among utility planning models because of its integrated, chronological and comprehensive characteristics. LMSTM is an electric utility system simulation model which integrates four submodels: demand, supply, finance and rates (see Figure E-1). Combined in this way, LMSTM simulates the interaction of customer demand, system generation, total revenue requirements and customer rates. LMSTM also preserves chronological load shape information throughout the simulation to capture time dependencies between customer demand (including DSM), and system operations and customer rates.

Demand Submodel

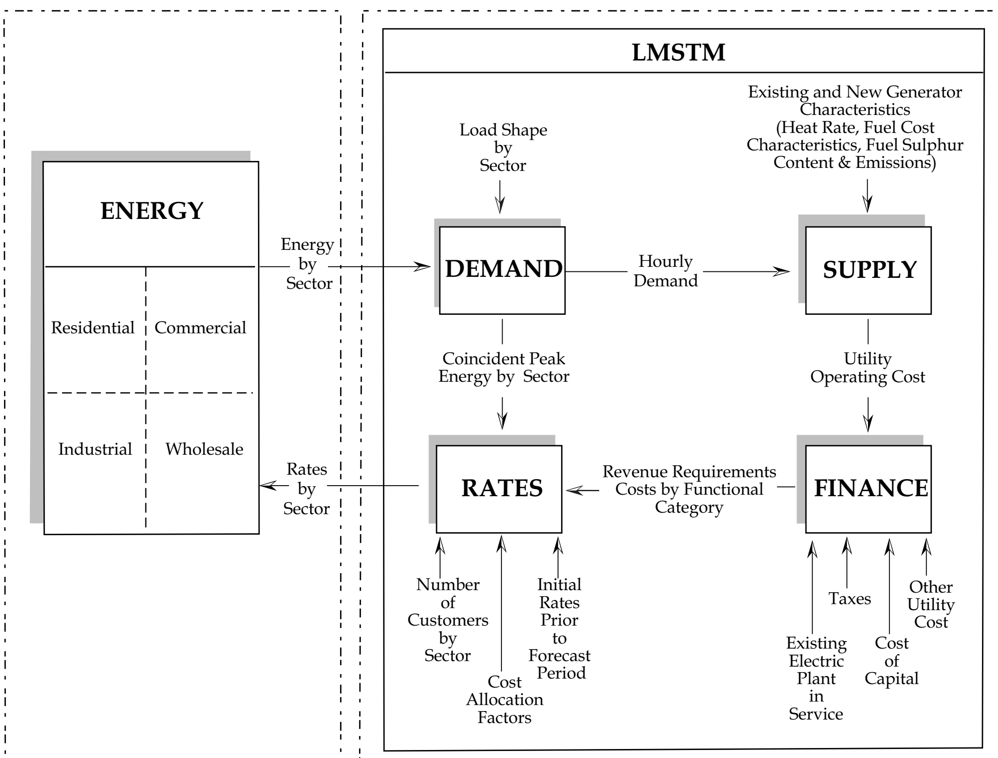
The demand submodel projects hourly demands for each customer class and DSM program for each year of the forecast period. This submodel builds up the system demand by aggregating the demands for each customer class. Major inputs to the demand submodel include annual energy use, load profiles and energy allocation factors for each customer class.

Supply Submodel

The supply submodel simulates the operation of the generation system: it commits and dispatches existing generating resources hour-by-hour in a way that minimizes the daily operating costs of meeting the pro-

FIGURE E-1

Electric Utility Simulation



jected system demand. By preserving the chronological order of system demand throughout the simulation, LMSTM retains hourly marginal costs rather than averaging them over a longer period and potentially losing extreme cost information. The major inputs to the supply submodel include hourly system demand (from the demand submodel) and detailed data for all existing and planned generating units, e.g., unit heat rates, fuel cost, annual operating and maintenance expense, and unit emission rates. The supply submodel also includes the expected in-service dates for planned additions to the generation system and utility investments in new generation.

Finance Submodel

The finance submodel simulates a utility's annual revenue requirements and assigns all costs and revenues to user-defined functional categories. DSM program costs are input to the finance submodel as a separate functional category and can be either capitalized in rate base or treated as an operating expense. Major inputs to the financial submodel include all existing assets, annual projections of ongoing capital investments in generation, transmission and distribution plants as well as annual operation and maintenance expenses. The cost of capital, tax rates and other financial parameters are also input to the model.

Rates Submodel

The rates submodel simulates the average cost-of-service for each customer sector. Cost allocation factors, based on hourly customer demands from the demand submodel (which include the projected load impacts of DSM programs) and other factors, are used to apportion revenue requirements in each functional cost category to each customer class. The allocation factors used by SUFG include each sector's contribution to peak, percent of total energy, percent of total number of customers or some combination of these factors. This method approximates traditional rate making methodology but with considerably less detail.

The above described methodology for finance and rates applies only to the IOUs. In contrast, the NFPs (HEREC, WVPA and IMPA) do not use a rate of return on rate base methodology. Public power agencies, such as these, typically set rates that achieve an acceptable financial condition as measured by a coverage ratio, such as current interest coverage. SUFG calculated a single such rate for NFPs. This rate can best be described as a member's average cost per kWh. Since SUFG does not have the ability to model the assets and costs for the individual REMCs and municipalities, the costs for these assets are excluded from the NFPs' rate calculations.

Integrating DSM Impacts Into the SUFG Modeling System

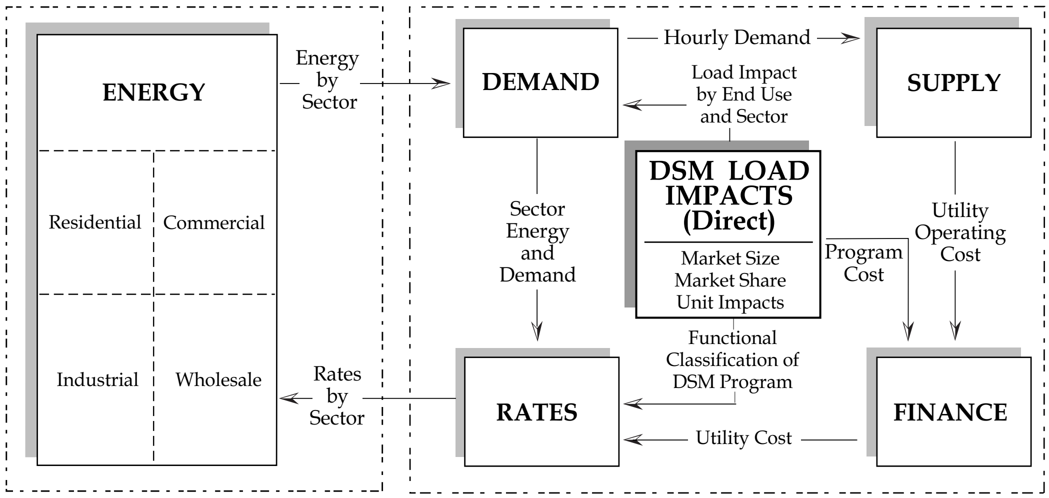
DSM programs can have many diverse impacts on a utility. DSM programs change system demand, which, in turn, alter the system operation, utility costs and electricity prices. As illustrated in Figure E-2, each DSM program's load impact and cost projections are integrated into the SUFG modeling system through LMSTM.

LMSTM's demand submodel builds up the total DSM load impact by accumulating the kW and kWh impacts of individual programs. The demand submodel aggregates the hourly demand of each DSM program with the corresponding sector's demand. Lastly, it aggregates the "net" demand across sectors to form system hourly demand.

Program costs are input to the financial submodel of LMSTM where the impact on the utility's total costs are measured and allocated among the various customer classes.

FIGURE E-2

Integration of DSM Impacts into SUFG Modeling System



LMSTM Input Assumptions

The rest of this appendix describes SUFG's input assumptions to LMSTM. Virtually all assumptions were obtained from the following sources: FERC Form 1, annual report, utility power requirements study, Rural Utilities Service (RUS) Form 7, and utility responses to SUFG's annual data requests, e.g., sectoral load profiles, DSM programs, generating unit data, cost projections for all existing and planned assets and other financial data.

Demand Submodel

Major inputs to the demand submodel include annual energy use, load profiles and daytype energy allocation factors for each customer class. Annual energy use by customer class is obtained from SUFG's energy submodel. (See Appendices B, C and D for a detailed discussion of SUFG's energy submodel.) Load profiles and energy allocation factors are required for each month and daytype. PSI Energy, I&M and IPL provided SUFG with load shape information for all three major customer classes. The PSI Energy load shapes were used to project system demand for NIPSCO, SIGECO and the three NFPs. Energy allocation factors were provided by each utility.

Supply Submodel

SUFG's resource plans include all current utility planned capacity changes as well as SUFG's projected generic generation additions to meet future load growth.

Planned utility capacity changes include: scheduled generation additions (certified); retirements, deratings, upgrades and net changes in firm purchases from out-of-state. Units that were approved by the IURC in 1999 were not included in this forecast due to time constraints. They will be incorporated in future reports. Lastly, Indiana capacity currently committed to out-of-state utilities is added to statewide capacity when existing contracts expire.

SUFG's projected generic generation additions are determined from a statewide as well as individual utility perspective. The SUFG modeling system matches supply to peak demand (plus a 15 percent reserve margin) on a statewide level by adding capacity whenever projected demand exceeds projected supply. These capacity additions are then allocated to individual utilities based on their individual need for generating capacity. The 15 percent statewide reserve margin used by SUFG is a reduction from the level of reserves used in previous SUFG forecasts. In the 1996 projections, SUFG presented a scenario that used a 15 percent reserve margin as an alternative to the traditional statewide 20 percent reserve margin. As a result of the continued lowering of utilities' reserves, SUFG targets a 15 percent statewide reserve margin for this forecast. (Individual utilities may utilize different reserve margins for planning purposes or they may use a different planning criterion, such as expected unserved energy or loss-of-load probability.) In addition, because of demand diversity, i.e., not all utilities experience their highest demand at the same time, the peak demand for the state will be somewhat less than the sum of each utility's peak demand. Consequently, a 15 percent statewide reserve margin results in less than 15 percent reserve margins for individual utilities. Typical reserve margins range between 9 and 12 percent for this forecast.

Generic generating resource options during the forecast period include:

1. 150 MW gas-fired combustion turbines,
2. 200 MW gas-fired combined cycle units and
3. 500 MW scrubbed, pulverized coal-fired units.

SUFG analyzed annual load data for each utility to determine which portion of the demand fell into each of three categories: (1) *baseload* -- the level below which the demand rarely falls; (2) *intermediate or cycling* -- the portion of demand which represents normal load swings between the daily minimum and maximum; and (3) *peaking* -- the demand during periods of unusually high consumption.

Similarly, SUFG assigned each generating unit to one of the three categories. When new capacity is needed to maintain a 15 percent statewide reserve margin, it is assigned to the utility with the lowest individual reserve margin. Next, that utility's demand level is compared to its generating capacity for each of the three categories. The type of unit assigned is determined to best match the demand and generating capacity by type. Hence, if the utility needs peaking capacity, it is assigned a combustion turbine. However, if it needs intermediate capacity, a combined cycle unit is assigned. Similarly, a utility that needs baseload capacity receives a coal-fired unit. Ownership of all new units is shared among utilities.

If an additional unit is needed to meet the 15 percent statewide reserve margin, it is assigned to whichever utility currently has the lowest individual reserve margin, using the procedure described above. In other words, the whole process is repeated as necessary to meet the target reserve margin.

There are two general exceptions to this protocol. SUFG assumes that IMPA and WVPA will meet their future resource needs by purchasing power from other in-state utilities.

SUFG makes no claim that these resource plans are necessarily optimal. Individual utilities may find it advantageous to acquire additional DSM resources, to purchase power from another utility or an independent power producer, or to construct other types of generation than those included in SUFG's portfolio of generation options. Additionally, IMPA and/or WVPA may find it advantageous to build their own capacity instead of purchasing from others.

Finance Submodel

Major inputs to the finance submodel include annual projections of utility investments in new generation, transmission and distribution plants as well as annual operation and maintenance expenses. SUFG has defined 13 functional categories:

- *Production Plant*: All investment and fixed operating costs for existing and planned generators, except nuclear. (Note: Fuel and variable O&M costs are classified separately.)
- *Transmission Plant*: All investment and operating costs for existing and planned transmission plant.
- *Distribution Plant:* All investment and operating costs for existing and planned distribution plant.
- *General Plant*: All investment and operating costs for existing and planned general plant.
- *Fuel and Variable O&M*: The fuel and variable O&M costs are classified separately from production plant costs because they are allocated to the rate classes by energy only, not energy and coincident peak demand as the other production plant items.
- *Street Lighting*: A separate functional category is needed for this item because the revenues and expenses for this must be separated from the other categories to prevent them from being included in the rate making calculation for the other sectors, i.e., residential, commercial and industrial.
- *Nuclear Plant*: The nuclear plants that serve the customers in Indiana receive their own functional category but are treated in the same manner as production plant.
- *Nuclear Fuel*: Costs are treated in the same manner as Fuel and Variable O&M.
- *Hydro Plant* : Costs are treated in the same manner as Production Plant.
- *DSM Plant*: All current and planned DSM investment and costs are included in this functional category.
- *Common Plant*: This functional category is used for those utilities that are a combined electric and gas or steam utility and share common facilities.
- *Gas Plant:* This functional category is used for the combined gas and electric utilities so that the assets for the gas side of their operations can be excluded from the rate making calculations for their electric customers.
- *Steam Plant*: This functional category is used for the combined steam and electric utilities so that the assets for the steam side of their operations can be excluded from the rate making calculation for their electric customers.

For new generating capacity additions which have already received a Certificate of Need from the IURC, SUFG relied on cost projections provided by the utility. Cost projections for the generic capacity additions used in the forecast for all scenarios are shown in Table E-1.

SUFG assumes that WVPA and IMPA satisfy their future power needs through purchased power arrangements from the state's five IOUS and HEREC. Wholesale purchase prices are based on an average of SUFG's wholesale price projections for the five IOUs.

The projected cost for all ongoing capital additions such as transmission and distribution plants was developed from information provided by each utility, and are the same for all SUFG scenarios. If the utility did not provide a full 20-year projection, SUFG projected the remaining years using a two percent real growth rate. Included in these estimates of all ongo-

TABLE E-1	
Generic Generating Units Capital Cost Assumptions (in 1996 Dollars)	
Unit Type	**Unit Cost**
Combustion Turbine 150 MW Unit	$330/kW
Combined Cycle 200 MW Unit	$490/kW
Conventional Coal with FGD System, 500 MW Unit	$1150/kW

Source: SEPRIL, L.L.C., *Plant Design, Performance & Cost Comparison Study*. August 1998.

ing capital additions is the utility's estimate of compliance costs for current state and federal environmental laws.

The O&M cost projections for all existing and planned generating units are based on information provided by the utilities. The O&M costs from the SEPRIL study were used for generic unit additions in each scenario.

O&M cost projections for existing and planned transmission, distribution and general plants were also provided by each utility. When the utility did not provide a full 20-year projection, SUFG projected the remaining years at a two percent real escalation rate. These cost projections do not vary across scenarios.

SUFG also used each utility's cost assumptions for the DSM programs included in our forecast. DSM programs, impacts and costs do not change across SUFG's scenarios. (See Chapter 8 and for a detailed discussion of DSM program assumptions and methodology.)

Rates Submodel

LMSTM's rates submodel is designed to produce annual electricity price projections for each major customer sector, which are subsequently input to SUFG's energy submodel. SUFG uses a traditional cost-of-service approach: cost responsibility for each functional category is assigned to each customer sector based on a weighting of the various cost determining factors. These factors include contribution to system coincident peak demand, share of annual energy and number of customers. The weight of each factor lies between zero and one, depending on its relative importance in determining costs within the functional category. In actual practice, cost-of-service methodologies are much more detailed, consisting of many rate classes and more detailed cost allocation methods.

LMSTM's cost-of-service methodology poses certain problems that are not present in more detailed approaches. For example, the costs of distribution and general plants are not typically allocated to the large user rate classes such as large commercial and industrial customers. However, since SUFG aggregates the large and small rate classes together for both industrial and commercial customers, a small portion of these costs ought to be included in the rates for SUFG's more broadly defined commercial and industrial rate sectors. LMSTM's cost-of-service methodology provides the flexibility to incorporate these effects by changing the weightings of the various factors that determine cost. In this case, a greater weight is assigned to customer share (60 percent) to reflect its relative importance in determining costs in this functional category. The majority of the distribution and general plant cost is then allocated to the sectors that have the largest number of customers. Typical cost allocation formulae for all functional cost categories are shown in Table E-2.

TABLE E-2

Cost Allocation Weighting Factors by Functional Cost Category

Functional Category	Cost Allocation Factor (%)			Rate Classes
	Peak	Energy	Customer	
Production Plant	70	30	–	R,C,I,W
Transmission Plant	70	30	–	R,C,I,W
Distribution Plant	20	20	60	R,C,I
General Plant	20	20	60	R,C,I
Fuel & Variable O&M	–	100	–	R,C,I,W,SL
Street Lighting	–	100	–	SL
Nuclear Plant	70	30	–	R,C,I,W
Nuclear Fuel	–	100	–	R,C,I,W,SL
Hydro Plant	70	30	–	R,C,I,W
DSM Plant	70	30	–	R,C,I,W
Common Plant	70	30	–	R,C,I,W
Gas Plant	–	–	–	
Steam Plant	–	–	–	

Note: Rate Classes: R = Residential C = Commercial I = Industrial SL = Street Lighting W = Wholesale

CENTER FOR ECONOMETRIC MODEL RESEARCH (CEMR)

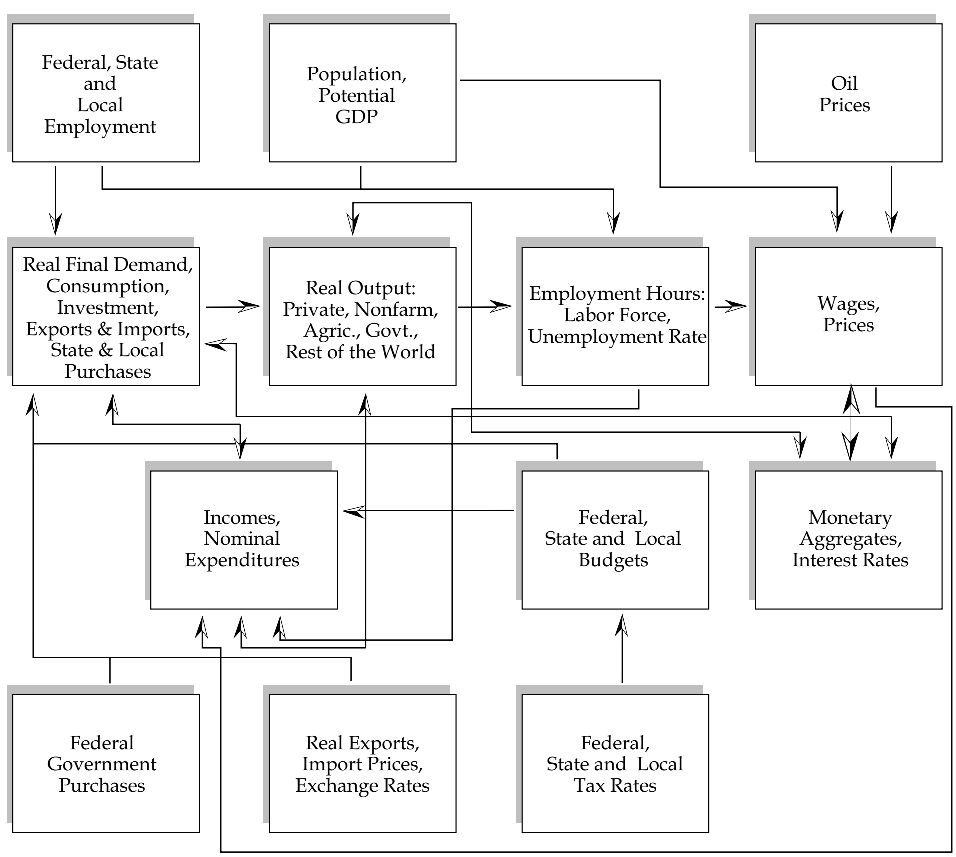
Macroeconomic Models

The procedure for generating long-range projections of the Indiana economy starts with a forecast of the U.S. economy for the next 20 years. The first three years of this forecast is the latest available quarterly CEMR control forecast for the U.S. economy, which utilizes the CEMR model of the United States. This same CEMR model is used to extend the forecast for an additional 17 years.

The CEMR model of the U.S. economy contains 218 variables, of which 56 are exogenous, that is, variables for which values must be assumed. The model is a set of nonlinear equations that are solved iteratively to obtain projections of all the 162 endogenous variables in the model. Behavioral equations are used to obtain forecasts of 59 variables, while projections of the other 103 endogenous variables are obtained from identities. These projections are conditional on the projections of the exogenous variables. The values of the exogenous variables for the last 17 years of the projection period are obtained by extrapolating the assumptions in the latest control forecast.Exogenous variables include several demographic variables, oil prices, potential GDP, international trade variables (export levels and import prices), various fiscal policy variables (government spending levels and tax rates) and several monetary policy variables. A flowchart of the model is shown in Figure F-1.

FIGURE F-1

Structure of U.S. Macroeconomic Model



Many of these exogenous variables impact the demand for goods and services. Output is determined by aggregate demand. Output influences employment and the labor market situation. Labor market tightness as well as oil and import prices then establish wage rates and domestic prices. Employment and wage rates, interest rates and several other variables determine income components, such as employee compensation, interest income and corporate profits. Fiscal policy variables interact with income variables to determine federal, state and local budgets. Monetary variables and interest rates interact with output and price variables to influence aggregate demand and interest rates.

Once the long-run U.S. projections are made, a second model, the U.S. satellite model, disaggregates the aggregate employment, average weekly hours and wage rate variables into employment, average weekly hours and wage rates by industry. Figure F-2 displays a flowchart of the U.S. satellite model. The disaggregation of these three variables is done by projecting industry shares of employment, hours and wage rates based on historical behavior. The industries covered are shown in Table F-1.

The third model used in generating the long-run projections is the Econometric Model of Indiana (EMI). This is a quarterly model also used to generate short-run forecasts of the Indiana economy. The exogenous inputs to this model are the U.S. employment, average weekly hours and wage rate variables from the U.S. satellite model as well as a number of U.S. income component variables from the U.S. macroeconomic model.

The structure of the EMI model is shown in Figure F-3. The employment, weekly hours and wage rate variables by industry in Indiana are modeled as functions of their U.S. counterparts. In effect, CEMR models the share of activity in each industry taking place in Indiana. Once employment, weekly hours and wage rates are projected for each industry, the variables can be multiplied to yield a wage bill for each industry. Aggregating the wage bill projections across industries yields a projection of total wages and salaries in Indiana. Other components of Indiana personal income are determined as shares of the corresponding U.S. personal income components. Adding aggregate wages and salaries and the other components of personal income yields the projection of total Indiana personal income.

The final part of the Indiana forecast involves projecting GSP by industry. First a set of assumptions is developed about the growth of productivity (GSP per hours worked) for each industry. These assumptions are based on historical rates of productivity growth. These GSP per hour projections are multiplied by projections of total hours worked in each industry to get the forecast for GSP by industry. Aggregating the industry GSP variables yields total GSP. This procedure is diagrammed in Figure F-4.

TABLE F-1

Industrial Detail for Long-Run Projections

Durable Manufacturing	Non-Durable Manufacturing	Non-Manufacturing
Furniture	Food	Mining
Primary Metals, except Steel	Apparel and Textiles	Contract Construction
Steel	Printing	Transportation
Fabricated Metals	Chemicals	Trucking
Machinery and Computers	Rubber and Plastics	Communication
Electronics and Electrical Equipment	Paper Products	Utilities
Transportation Equipment, (except Automobiles and Parts)	Other Non-Durables	Wholesale Trade
Automobiles and Parts		Retail Trade
Lumber and Wood		General Merchandise
Stone, Clay and Glass		Finance, Insurance, Real Estate
Instruments		Banking
Other Durables		Service and Miscellaneous
		Health Services
		Federal Government
		State & Local Government
		Educational Services

FIGURE F-2

U.S. Satellite Model

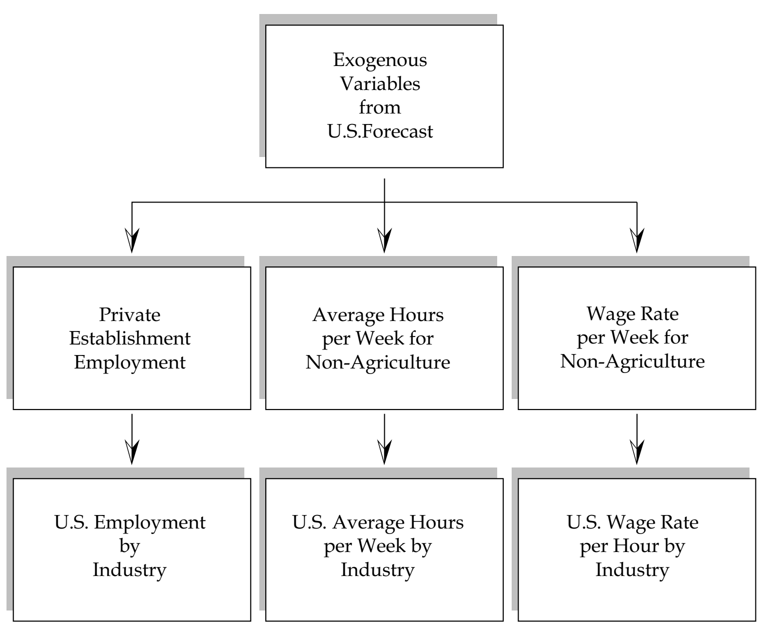


FIGURE F-3

Structure of Indiana Macroeconomic Model

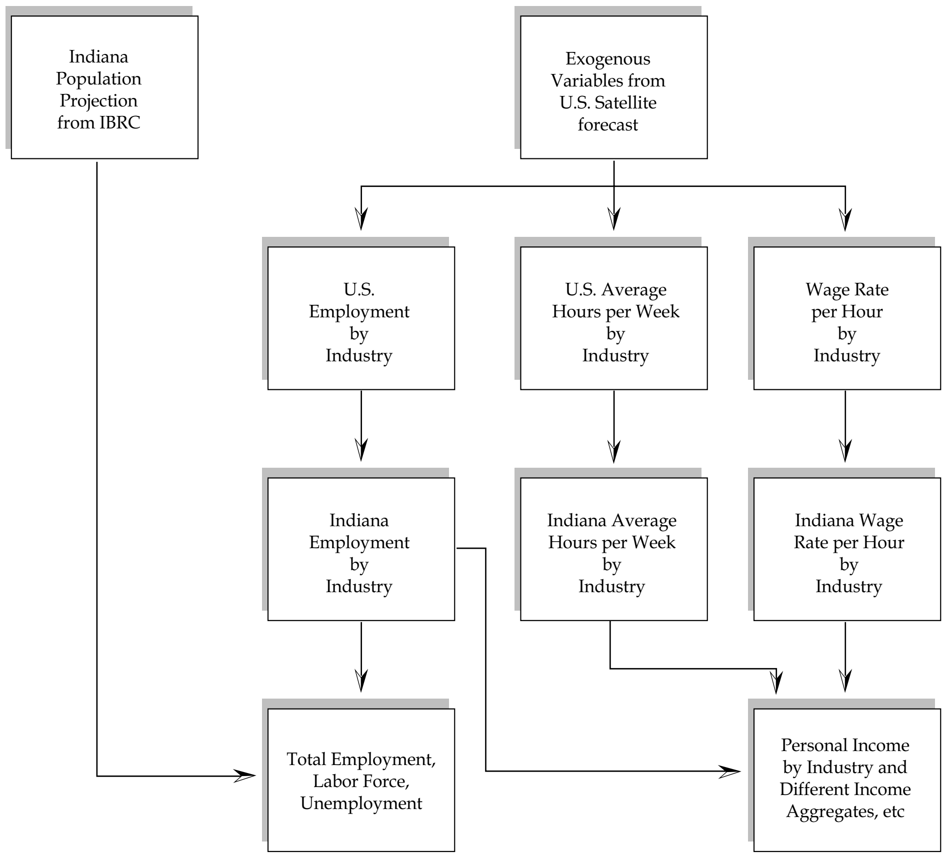
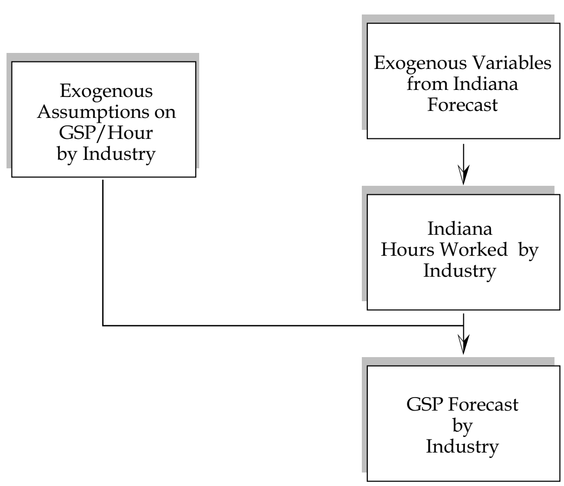


FIGURE F-4

Indiana GSP Model



COMPETITION: CONCEPT AND MODELS

The Basics of Average and Marginal Cost Pricing

This section discusses the concepts behind the comparison of the likely rates under traditional regulation, an average cost-based framework, with likely prices under a market-based structure, a marginal cost-based framework. The average cost-based scenario was simulated using SUFG's existing modeling system for the regulated electricity industry. The marginal cost-based scenarios were generated with the new competitive regional model, which reflects competitive power generation markets in the U.S. The variances between the price projections of each framework are the result of differing dynamics. One key factor that causes the price projections to diverge is the difference between average and marginal cost. Average and marginal cost can be expected to follow separate relative paths as:

1. restructuring begins while there are still surplus economic generating assets, with marginal cost reflecting only operating cost;
2. the current surplus is rapidly employed to meet future demand growth; and, when exhausted,
3. the marginal cost must then expand to include new investment in plant and equipment.

A key factor in this last consideration is the expected cost of future generating plant equipment. Recent technological advancements have resulted in substantially more efficient equipment at a much lower cost.

Average Cost vs. Marginal Cost

Traditional regulatory practice in the electric utility industry determines rates by the average cost of production. This structure gives utilities the exclusive right to serve customers in their franchise areas in return for their charging a tariff approved by the regulatory commission. This rate allows utilities to recover the total cost of production including a fair rate of return on the investments that are part of the rate base. The tariff is calculated by dividing the total revenue required to recover the total cost of serving all customers by the expected level of sales, and hence, the term average cost-based pricing.

While the transmission and distribution segments of the industry are expected to continue to be regulated in this way, it appears likely that the generation of electricity is to be opened up to competition. It is hoped that the "invisible hand" of competition will substitute for regulation as a means of assuring public access to fairly priced electricity.

If the competitive market structure for generation works correctly, the price of electricity will be determined by the variable or marginal cost of producing the last unit or load increment that needs to be brought into the market to meet the existing demand at any point in time, and hence, the term marginal cost-based pricing. In other words, to satisfy the amount of electricity that is required from the system, the price has to match the variable cost of producing the last unit of electricity for this system, consisting of fuel costs, variable O&M costs, and any other costs which change with output. Unless this condition is met, there will not be enough incentive for the producer of the last unit to offer this product into the market and the market will not equate demand with supply. If excess market power on either side of the market develops, prices can be held above this price by sellers with such power, or pushed below this price by buyers with market power. Thus, the degree actual prices depart from marginal costs can be viewed as an indicator of the presence of excess market power.

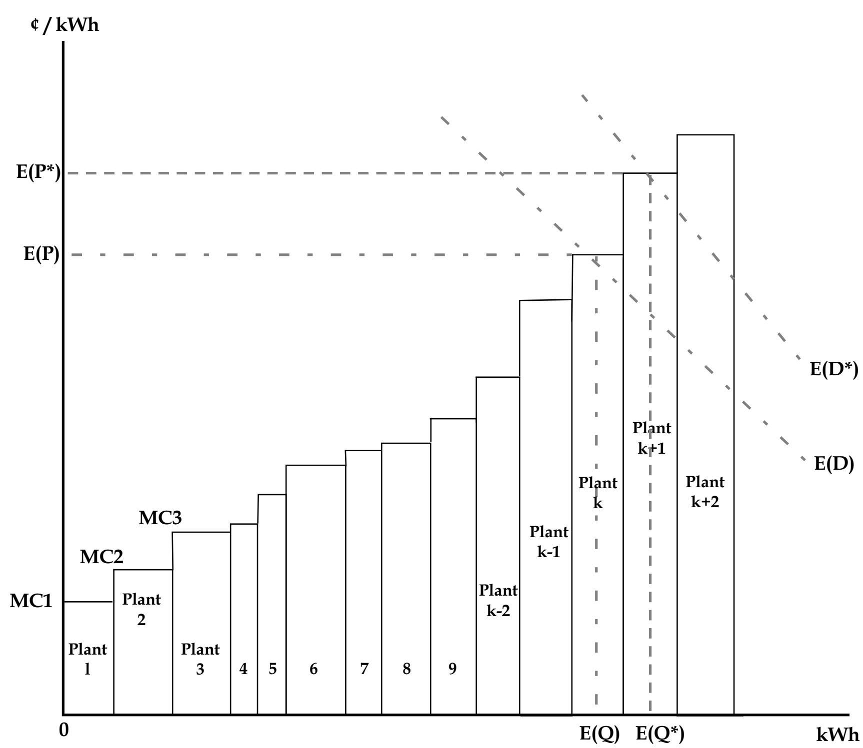
In average cost-based pricing, all prudent investments that are part of the rate base are guaranteed the opportunity to earn a fair return by the mechanism that sets the rates. In marginal cost-based pricing, however, there are no guarantees; market conditions govern. It is quite possible for some owners of low variable cost generating units to operate under market conditions where the price level set by the marginal unit in the system results in revenues in excess of that required to recover operating costs plus a fair return for the units that they own. It is also equally possible, with the prevailing market price levels set by marginal costs, for some other high variable cost generating unit owners to be unable to recover these costs. Under the latter conditions, owners of such units will experience what is termed by the industry as stranded costs. Similarly, the owners of units that are able to generate revenues in excess of total costs will be enjoying what has been defined as stranded benefits.[1]

Distinguishing between average and marginal pricing mechanisms and Indiana utilities' positions with respect to stranded costs and benefits is critical in understanding the implications of restructuring in Indiana.

Figure G-1 depicts the expected short-run price for electricity under a marginal cost-based pricing mechanism, e.g., one that would arise from a power exchange

FIGURE G-1

Marginal Cost-Based Pricing



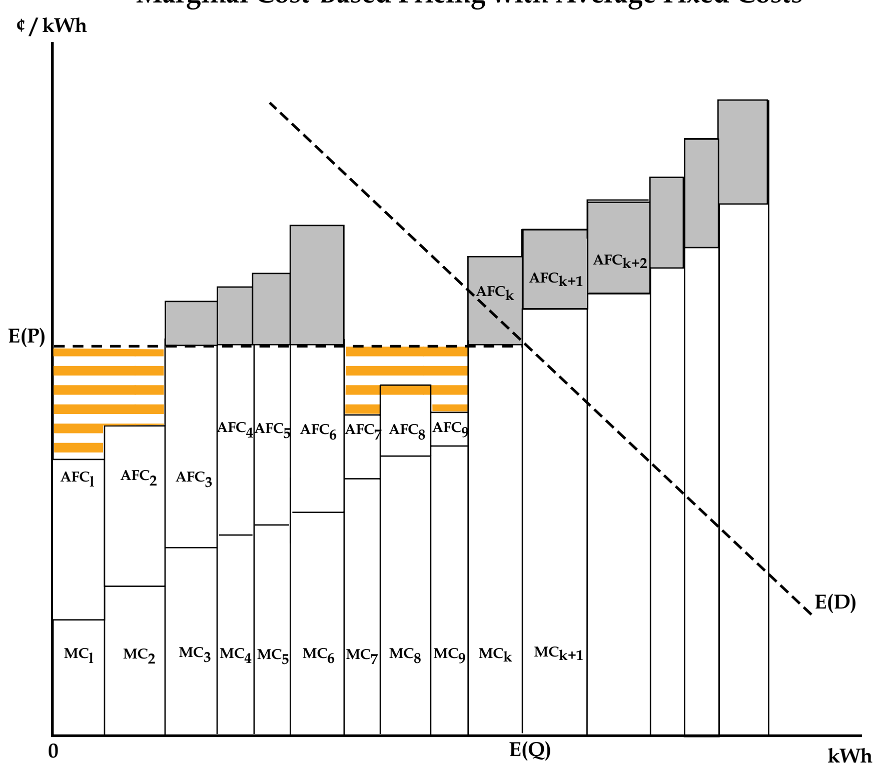
[1]The term, stranded benefits, is often used in a broader sense to include social and conservation programs. Its use within this document is restricted to the excess of generation revenues over total costs.

where offers to buy and sell electricity at given prices are equated by adjusting price up or down until demand equals supply. Here, the vertical axis is the marginal cost of electricity and the horizontal axis is the quantity of electricity produced and demanded. Each bar represents a generation plant with respective marginal costs of production (variable production costs) and the quantity of electricity each can supply to the market. The plants are ordered from the lowest marginal cost of production to the highest. E(D) is the expected level of demand with respect to price during the interval. The market clearing price, E(P), which all generators receive is determined by the level of marginal cost associated with the last unit of production that satisfies the demand level given by E(D). At that level, plants (1) - (k) will be dispatched to supply the required quantity of electricity E(Q). Notice that at that level, plant (k) breaks even in terms of variable operating costs. Plants (1) - (k-1) recover more than their marginal costs (by an amount equal to the difference between E(P) times Q_i and MC_i times Q_i for each plant). Plants (k+1) and (k+2) would not be operating since the market price, E(P) , is not high enough for these plants to recover variable operating costs.

If the demand for electricity was higher, such as E(D*), then the price for electricity would increase to a level that is high enough for the next production unit to enter the market. In our example, this level is E(P*) which is the break-even level for plant (k+1) - the available unit with the next lowest variable operating cost. Since the position of the demand curve will vary hour by hour over the year, the yearly average price would be the kWh weighted average of the 8760 hours in the year.

FIGURE G-2

Marginal Cost-Based Pricing with Average Fixed Costs

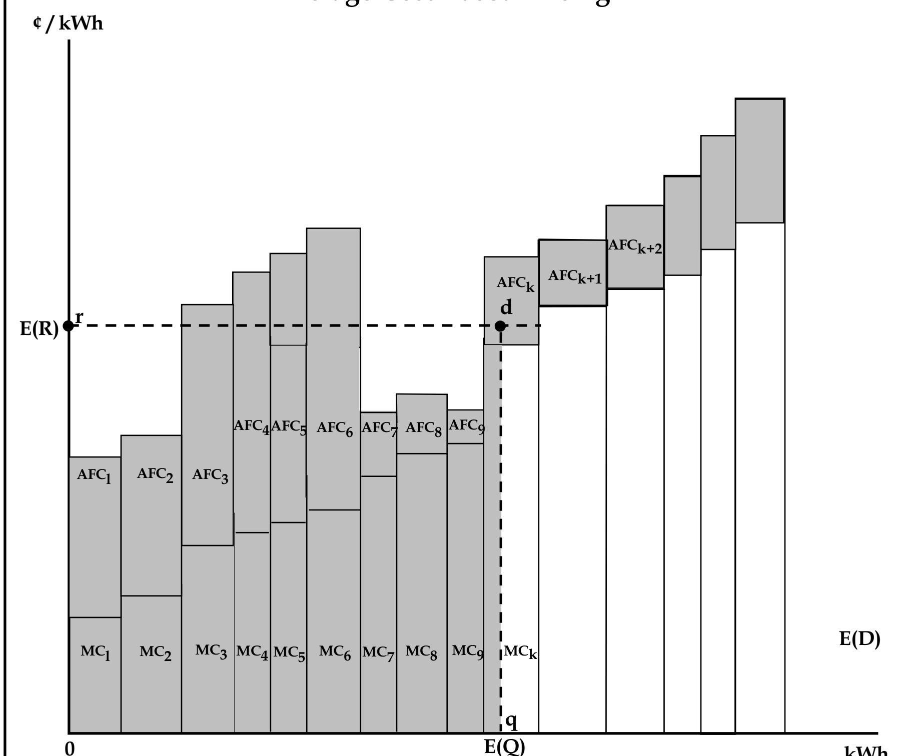


Operating plants not only have variable costs, but also have fixed costs associated with their investment in plant and equipment to recover. Figure G-2 shows average fixed costs (AFC)[2] along with variable operating costs (MC) for each plant. In this example, at price level E(P), assuming marginal cost pricing, plants 1, 2, 7, 8, and 9 will generate revenues well over variable costs plus average fixed costs, and plants 3, 4, 5, 6, and (k) will recover operating costs but only a part of average fixed costs. The shaded areas above E(P) indicate the shortfall — so called "stranded costs." The barred areas above MC plus AFC for plants, 1, 2, 7, 8, and 9 indicate the surplus—so called "stranded benefits." Net stranded costs would be the stranded cost area minus the stranded benefit area in the figure.

Figure G-3 depicts the outcome for the set of plants, assuming average cost-based pricing i.e., (1) - (k) in Figure G-2 are owned by Utility X and operated to serve customers in a certain franchise area. As before, suppose the total demand in the franchise is E(Q). The utility has to build and operate plants (1) - (k) to meet total demand. At this level, total cost of service to the

FIGURE G-3

Average Cost-Based Pricing



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[2]Average fixed costs are usually calculated by dividing depreciation plus interest on the unrecovered investment plus allowances for taxes and other fixed expense by planned generation.

utility is the sum of all shaded bars representing the average fixed and variable costs for all operating units. The price level, E(R), (i.e., the rate) that will recover the shaded fixed and variable costs is calculated by dividing the sum of all fixed and variable costs by the quantity sold; that is, the E(R) such that:

$$E(R) = \frac{\sum_{i=1}^{k} (AFC_i + MC_i)(KWh_i)}{E(Q)}$$

The area contained within the rectangle, rdqo, is equal to the sum of the shaded areas under the cost bars for each operating plant. Thus, under the present regulation, rates based on average cost-based pricing allow all prudent costs (here defined as the costs of all operating plants) associated with providing service to customers to be recovered by utilities.

Would rates which are determined by average cost-based pricing E(R) in Figure G-3 and prices prevailing under marginal cost-based structures (E(P)) in Figure G-2 as discussed above be the same? Only by accident. With demand unchanged, a key factor in determining whether marginal cost-based pricing will result in higher or lower prices is the undepreciated book value of generation assets. Figures G-4 and G-5 present two possible scenarios where rates under average cost-based pricing ($E(R_1)$) are different than prices under marginal cost-based pricing (E(P)). In Figure G-4, marginal cost pricing will result in a price E(P) and an amount supplied equal to E(Q). Due to the high value

FIGURE G-4

Stranded Costs Exceed Stranded Benefits

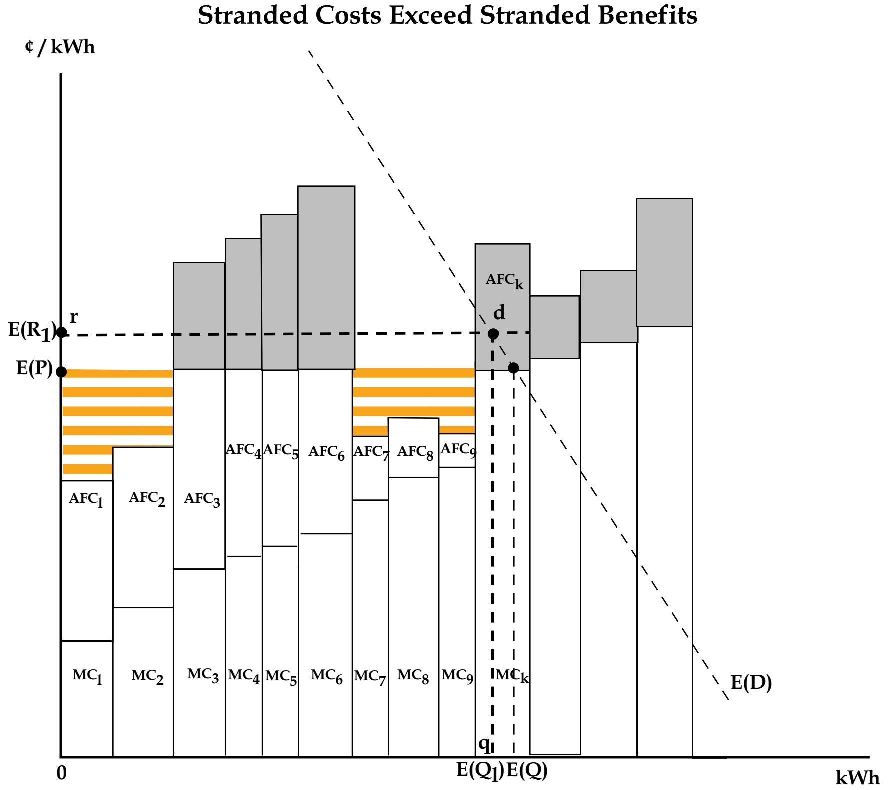
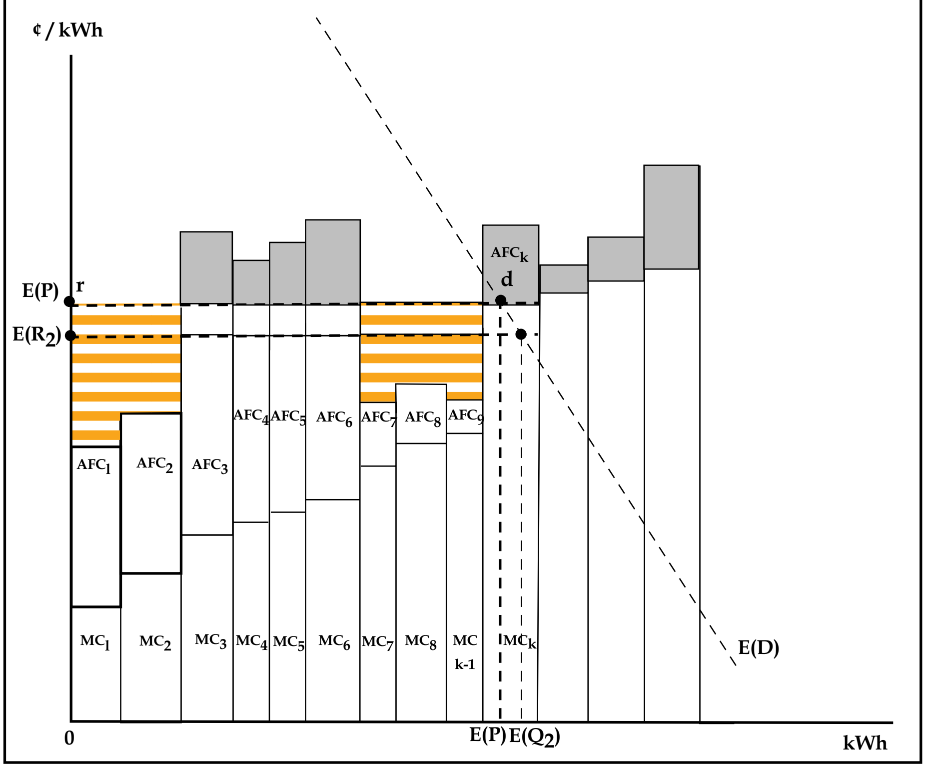


FIGURE G-5

Stranded Benefits Exceed Stranded Costs



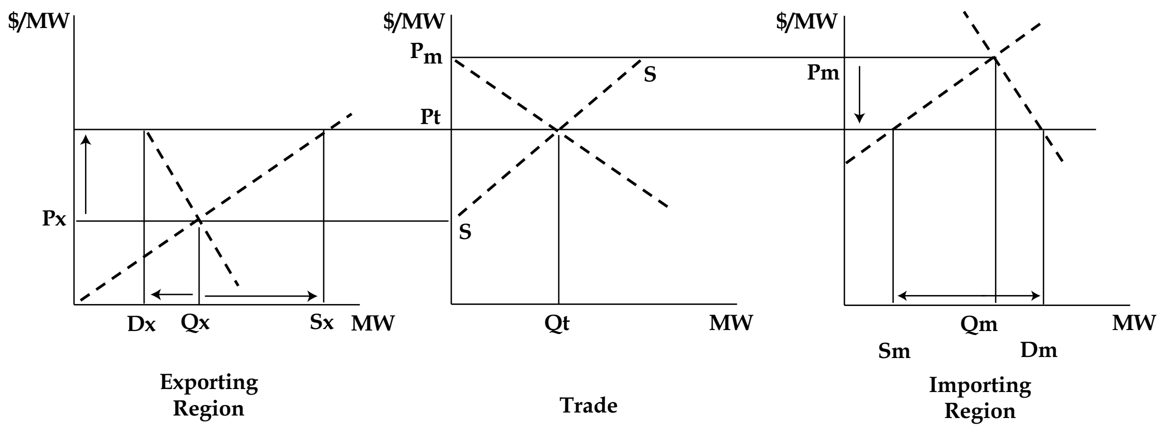
of average fixed costs (e.g., large book value), total revenue requirements under average cost-based pricing results in a higher price level ($E(R_1)$) than under marginal cost-based pricing (E(P)). As a result of higher prices, quantity demanded will decline to ($E(Q_1)$) . In this scenario, total revenue generated under marginal cost-based pricing (E(P) times E(Q)) is less than total revenue generated under average cost-based pricing ($E(R_1)$ times $E(Q_1)$). What this means is that in this instance, the shaded area above the E(P) line, the amount of average costs not recovered for plants 3, 4, 5, 6, k-1 and k, (the stranded costs), is greater than the crossed hatched area between the average fixed costs and E(P) for plants 1, 2, 7, 8 and 9 (the stranded benefits). Consider now Figure G-5. Here, average fixed costs are relatively low, and therefore, the total revenue requirement under average cost-based pricing results in rates ($E(R_2)$) being lower than prices under marginal cost-based pricing E(P)). Here, the shaded area above the E(P) line, stranded costs for plants 3, 4, 5, 6 and k, are less than the cross-hatched areas between the AFC and E(P) , the stranded benefits, for plants 1, 2, 7, 8 and 9.[3]

To summarize, assuming that competitive prices are set by a power exchange market mechanism where the market price received by all generator owners is

[3]These pictures represent what happens during one point in time, i.e., one hour or year. True evaluation of stranded costs and benefits requires summing the net present value of these amounts positive and negative over the life of the assets.

FIGURE G-6

Trade Diagram



the variable cost of the most expensive unit dispatched to meet demand and no significant change in the demand as a result of restructuring takes place, then:

- The direction and magnitude of the price change which takes place after restructuring depends primarily on the magnitude of the average costs allowed to be recovered under continued regulation.
- If allowed average fixed costs are low, as would be the case with a utility with a mostly depreciated asset base, then stranded benefits may exceed the stranded costs with competition and prices under restructuring are higher then would be the case with regulation.
- If allowed average fixed costs are high, as would be the case with a utility with relatively new, undepreciated assets, then stranded costs may exceed stranded benefits with competition and prices would be expected to fall with restructuring.

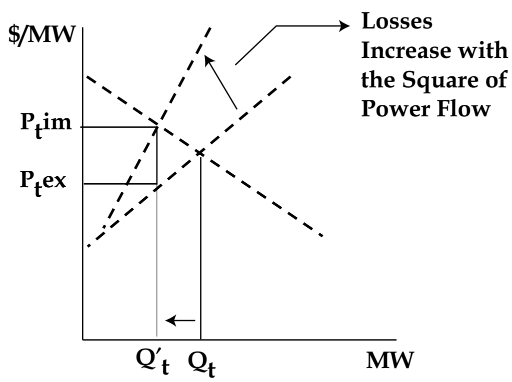
Factors Controlling Electricity Trade

The export/import model used by economists allows for trade to take place between regions with differing generating costs until the rising cost of producing for export demand meets the falling price import regions are willing to pay for imports. This model assumes marginal cost pricing both before and after trade. The methodology can be illustrated using a three panel diagram showing the fundamental economics of trade. This is illustrated in Figure G-6. The panel on the left represents the supply and demand schedules for the low-cost, exporting region, and the panel on the right represents the supply and demand schedules for the higher cost, importing region. The middle panel shows derived schedules for excess demand of the importing region and excess supply of the exporting region.

Px is the price in the exporting region before trade, i.e., where supply and demand cross in the region At that price, consumers want to purchase exactly the amount producers want to sell (Qx). However, if higher prices were to prevail, then suppliers would offer additional production. At the same time, con-

FIGURE G-7

Trade with Increasing Losses



Trade

sumers would offer to purchase less. Hence, there is excess supply at prices higher than Px in the amount of the difference between the points along the demand curve and the points along the supply curve. The situation will be reversed in the importing region. There will be excess demand when prices are lower than Pm. The curves in the middle panel are constructed by tracing out the excess supply schedule from the exporting region rising from Px and excess demand schedule from the importing region falling from Pm. Assuming no transaction costs[4] (i.e., losses and transmission fees), the equilibrium price with trade will be equal to Pt and quantity Qt will be traded (i.e., produced by the exporting region and sold to consumers in the importing region). Quantity consumed in the exporting region will decline, from Qx to Dx. Quantity produced will increase from Qx to Sx. Quantity consumed in the importing region will increase, from Qm to Dm. Quantity produced will decline from Qm to Sm. If any trade restrictions are present, a wedge is driven between the price received by the exporting region and the price paid by the importing region. Thus, in Figure G-7, if the fraction of transmission losses were C, the exporting region would receive

$$p_t^{ex} \text{ per kWh,}$$

the importing region would pay

$$p_t^{im} = p_t^{ex} * (1 + C)$$

and trade would be reduced to

$$Q'_t \text{ rather than } Q_t.$$

Many of the concepts illustrated in the trade diagram apply to the new regional competitive model. Examples of restrictions to trade which are included in the model are transmission fees, losses and importantly, congestion as a result of lines nearing their rated limits.

Gainers and Losers with Trade

There are four sets of stakeholders who are differentially affected by the trade illustrated in Figure G-6:

1. consumers in the exporting region;
2. producers in the exporting region;
3. consumers in the importing region; and
4. producers in the importing region.

Briefly stated:

- Producers in the exporting region and consumers in the importing region are helped by trade.

[4]Transaction costs result in less trade. With trade, prices in the importing region are higher than those in the exporting region by the amount of the marginal transaction costs. It should be noted that exit fees associated with stranded cost recovery do not necessarily reduce exports. See Tye & Graves, "Stranded Cost Recovery and Competition on Equal Terms," *Electricity Journal*, December 1996, pp. 61-70.

- Consumers in the exporting region and producers in the importing region are hurt by trade.
- The trade gainers can always compensate the trade losers for any loss, and still come out ahead, e.g., there are always net gains from trade.

How does this come about?

- Consumers in the exporting region are worse off — they see their electricity prices bid up by high-cost regions from Px to Pt (Figure G-6), which causes them to reduce their consumption from Q_x to D_x in the figure.
- Consumers in the importing region are better off — they see the impact of low-cost imports as a decrease in their electricity price from Pm to Pt, which causes them to increase electricity consumption from Qm to Dm.
- Producers in the exporting region are better off — they see the price of their electricity rising from Px to Pt as a result of the export demand Qt; total MW sales increase as well, from Qx to Sx. Thus, profits increase because of increased price and increased volume.
- Producers in the importing regions are worse off — they see not only a reduction in the price of electricity from Pm to Pt, but also see their volume decreases from Qm to Sm, as consumers substitute Qt MW of low-cost imports for their locally generated power.

The bottom line of all this is simple. Without some intervention, the interests of stockholders and ratepayers, at least in the short run, are diametrically opposed with regards to the impact of trade in electricity. Consumers in high-cost states and producers in low-cost states will be strong supporters of trade — both stand to gain from it — one in the form of reduced prices paid, the other in the form of increased profits. Conversely, ratepayers in low-cost states and producers in high-cost states will have their doubts regarding the wisdom of free trade — for equally obvious reasons. Should their arguments prevail? Certainly not. Trade in electricity, if properly structured, has the ability to make all parties better off — producers and consumers alike in low-cost as well as high-cost areas. The mere existence of potential losers should not be used as an argument for not supporting electricity trade; rather, means should be found to allow the winners in trade - producers in low-cost states, consumers in high-cost states - to compensate the losers in trade - consumers in low-cost states, producers in high-cost states in such a way as to keep intact the power of open competition to reduce costs.

Market-Based Pricing Framework

SUFG has employed three approaches to look at the likely effects of restructuring. The first, presented in SUFG's 1996 projections, was a simple two-region electricity trade model where Indiana electricity exports were limited only by transmission charges and the size of the trading region. This approach suggested Indiana electricity prices would be higher under competition if the transmission system could support significant exports of Indiana's low-cost power. The second approach was substantially more sophisticated and explicitly modeled the likely flows of electricity within the state under competition under various levels of assumed exports from Indiana. The third approach, which is used in this report, models the flows in the combined regions of MAIN and ECAR and determines Indiana's level of imports and exports internally.

The first approach examined potential trade and the likely effects from that trade between Indiana and two regions — ECAR combined with MAIN and the

Eastern Interconnection. An important question was how large an area outside Indiana was appropriate to consider. One possibility was that transmission constraints, power flow losses, and other transaction costs would be enough to restrict the area of interest to the surrounding states. This might be an area described by NERC's ECAR and MAIN regions. SUFG looked at this and found that the potential for substantial net trade with the rest of ECAR and MAIN was limited. Variable production costs are similar to Indiana costs for plants in these regions; Indiana plants do not have an overwhelming competitive advantage. Another possibility is that trade could extend to the entire Eastern Interconnection, particularly to the Northeast Power Coordinating Council (New York and New England Power Pools) and the Mid-Atlantic Area Council (PJM Interconnection). SUFG found in this case that Indiana had a substantial competitive advantage if the transmission system would allow a substantial amount of energy interchange. Interestingly, utilities outside ECAR and MAIN currently have greater overall surplus generation capability than ECAR/MAIN utilities. This shows up in terms of higher estimated capacity margins which are readily available in a number of publications such as NERC's annual electricity supply and demand reports. However, only *economic* surplus capability will count under competition. Here the tables are turned. ECAR and MAIN have significantly greater surpluses of low-cost generation capability compared to utilities outside ECAR and MAIN. The simple two region approach suggested that Indiana utilities would export substantial quantities of power if the transmission system would allow that. In that event, increased production to serve exports, in addition to growing needs within the state, would begin to fully employ Indiana's surplus capacity. This simple first study suggested that by around 2005 market-based prices would be substantially higher than projected under continued regulation.

The second approach, the Indiana state model, was featured in SUFG's 1998 Interim Report. This model was a short-run stand-alone model illustrating how hourly electricity prices in Indiana might be set in a competitive world given:

1. current Indiana generator operating costs and capacities;
2. current transmission line capacities that link the generating units to the load centers;
3. projected demand growth at Indiana load centers taken from the SUFG "LCC" 1996 load projection;
4. projected growth in exports/imports to and from MAIN and ECAR;
5. a power exchange that clears the market for power each hour; and
6. the power flow equations dictate the paths electricity will take given the net power injections.

Thus, the state model was an hourly economic dispatch model that choses the least-cost mix of Indiana generation units that satisfies predicted Indiana and export demand over a given planning horizon. The model was spatial, which allowed transmission losses between Indiana's generating units and demand nodes to play a role in the least-cost dispatch.

The latest version of the SUFG competitive model maintains the improved features of the state model (i.e., power flow constraints, network capacity limits, hourly market clearing prices), while determining Indiana's level of hourly imports and exports internally. In the state model, exports were exogenous to the model and were handled by assumption.

The current version of the model includes 32 utilities in the ECAR/MAIN region along with six import/export nodes to other NERC regions (see Figure 9-2 in this report). The characteristics of the transmission lines (themselves equivalents of a much larger set of lines), control the flow of electricity between nodes according to the flow relationships given by the DC approximations of the AC power flow equations.

Line losses are piecewise linear approximations of the quadratic line loss functions. Hourly demands at each of the nodes were derived as explained in the following section. Three hour loads are combined into one hour for each utility to gain computation speed. Hence, 2,920 hours are simulated for each year.

Plant capacities are taken from the SUFG data base, derated for unexpected outages; scheduled maintenance is simulated for off peak seasons to minimize disruption. The operating marginal costs of the generation units are projected through 1998 to 2007 from the SUFG database. They include fuel costs projected to grow at the rates predicted by EIA, and variable O&M costs, expected to decrease at rates contained in the EIA's report on competitive electricity prices.[5]

A one-year run of the model solves on the General Algebraic Modeling System (GAMS) optimization system in about 80 minutes on a Sparc-20 workstation. The planning horizon varies depending on the scenario since the system is run until the short-run market clearing price of electricity reaches the estimated long-run cost of electricity.

State and Regional Demand Schedules

In SUFG's 1999 version of the competitive model, demands are projected from the hourly loads of the 32 demand points in 1994. Hourly load shapes were obtained from FERC Form 714 for 1994 when available. When the load data were unavailable, the hourly load shape for the appropriate NERC region was used. These shapes were scaled to fit data on annual energy consumption and summer peak for each utility within the region. Energy and peak data included requirement sales for resale and excluded non-requirement sales for resale. This serves as an approximation for excluding sales to other utilities that are explicitly in another region of the model and including sales to other regions that are not explicitly modeled. Annual load growth of 2 percent is assumed in each region of the model.

State and Regional Dispatch Schedules

Regional supply schedules are based on operating cost data for generating units in the 32 utilities in ECAR/MAIN. These are similar to traditional dispatch schedules and show how much it costs to serve any particular load level. Dispatch schedules are based on fuel and variable O&M costs.

Fuel costs are based on average heat rates obtained from EIA Form 860 for each existing unit. Though heat rates vary with output level, generally decreasing somewhat to the recommended operating level and then increasing if higher output levels are needed, the changes are fairly small through normal operating levels and average heat rates should serve as a sufficiently close approximation. Fuel prices are more problematic. Fuel prices vary by quantity, location and for coal, by specific coal characteristics. Coal is not a homogeneous commodity. Coal from different locations has very different heat content and other charac-

[5]Energy Information Administration, *Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities: A Preliminary Analysis through 2015*, Department of Energy, DOE/EIA-0614, September 1997, Executive Summary, Figure ES2. Projected Regional Retail Electricity Prices under Regulation and Competition, 2000.

teristics. Coal-fired units are constructed to burn specific coals having specified Btu contents and other characteristics. Thus, a coal price applicable for one unit is not applicable for another. So base year prices for the coal(s) applicable to each generating plant were obtained from EIA Form 423. For forecasting, these models have the capability to use differential rates of change for natural gas, coal, oil and nuclear fuels.

Operating costs were obtained from electronic copies of FERC FORM 1 and are available by plant site. SUFG did not attempt to use this data directly, that is by mapping plant average operating costs to individual generating units. Operating costs vary significantly from one year to the next and even more importantly, unit operating costs are highly dependent upon the capacity factor for the unit. Therefore, the 1994 to 2006 fuel prices of the plants are projected against the prices of 1994. The average change of fuel prices for a specific year is taken from an EIA forecast. Total O&M is about 5 mills for coal-fired plants - higher for nuclear plants and gas- and oil-fired generation units. Variable O&M costs are included in the dispatch schedules. Fixed O&M costs are used in calculations of utility profitability and in evaluating new plant construction but do not affect prices Estimates of variable O&M costs for existing units are provided

TABLE G-1

O&M Costs for Existing Generation Units ($/MWh)

	Variable
Hydro	3.0
Coal	2.5
Gas	3.5
Oil	3.5
Nuclear	7.7

in Table G-1.

Both planned and unplanned outages are accounted for by derating the capacity of each generating unit. Planned outages are assigned to spring and autumn months only since it is more profitable to operate the units during the winter and summer peak demand periods. For example, a 100 MW unit with a 10 percent annual planned outage would have 100 MW available during the winter and summer months, but only 80 MW during the spring and autumn. Unplanned outage derating applies equally year round. Table G-2 lists the annual planned and unplanned outage rates for various units based on information for new generating units of each type.

TABLE G-2

Annual Outage Rates (Percent)

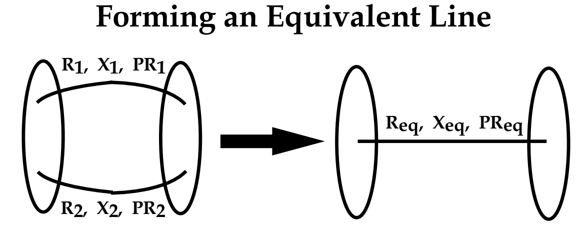
	Planned	Unplanned
Hydro	4	4
Coal	11	10
Gas	9	9
Oil	9	9
Nuclear	7	20

Transmission Modeling Methodology

To capture the limitations and losses associated with the transmission of power in the Eastern Interconnection, information was acquired electronically for the various NERC regions (FERC Form 715). This information included, among other things, the resistance, reactance, and power flow ratings of thousands of the transmission lines and transformers found in the interconnection. Since the various regions include lines and transformers from neighboring regions, care was taken not to double count transmission equipment

FIGURE G-8

Forming an Equivalent Line



when combining the regional data to form a database for the entire interconnection. The combined system resulted in tens of thousands of lines and buses. The enormous size of the system prohibited the performance of an hourly analysis in a reasonable period of time. A significant reduction in size was necessary. Furthermore, in order to analyze the power flows at that level of detail, the corresponding bus for generating units and load centers would have to be determined within each control area. This would entail determining the proper bus for each of the thousands of generating units and projecting the hourly load for each bus.

The first step in the size reduction process involved the aggregation of lines and buses located within the control area. All buses in a control area, both load and generation centers, were combined to form one central node. All transmission equipment that does not connect to a different control area were also condensed to that single point. Therefore, the new system consisted of one bus per control area, interconnected by the tie-lines. The total native load and generating capacity for a control area was located at its bus. This aggregation step sacrifices some accuracy, especially in systems with widely dispersed loads or generation. For more densely packed utilities, the aggregation step should have introduced a lesser amount of inaccuracy.

Many modeling advantages were achieved by this simplification. First, the size of the problem became more manageable by severely reducing the number of buses and transmission lines. Second, the dispersion of load and generation within a control area no longer needed to be determined. Third, it focused the analysis of the transmission system to the capability of power transfer between utilities, rather than power transfer within a single utility.

The accuracy of this aggregation depends on the density of the load, generation and transmission system, as well as the capability of the transmission system to adequately and safely transmit power inside the control area. Losses internal to the control area were handled by adjusting the demand level, thereby changing it to required, generated or purchased energy. The inclusion of wheeling losses are discussed later in this section.

The next step in simplifying the transmission model was the equivalencing of multiple tie-lines between two utilities into a single tie-line. Since the portion of the total system that is entirely internal to the control area had been condensed to a single bus, all tie-lines connecting two control areas were effectively parallel lines. Using circuit analysis techniques, the lines could be combined to form a single equivalent line, as illustrated Figure G-8.

The equivalent resistance, R_{eq}, was found from the resistances of the original lines, R_1 and R_2, using the

$$R_{eq} = \frac{R_1 R_2}{R_1 + R_2}$$

formula

If more than two parallel lines existed, the procedure was repeated until all lines were equivalenced to a single line. The equivalent reactance, X_{eq}, was determined in a similar manner. The power flow rating of the equivalent line, PR_{eq}, was found using the current divider method, as follows. For a given amount of power transferred between the two utilities, P_x, the flow levels on each line are found from the following

$$P_1 = P_x \frac{X_2}{X_1 + X_2} \quad and \quad P_2 = P_x \frac{X_1}{X_1 + X_2}$$

formulae,

Therefore, the power rating of the equivalent line, PR_{eq}, was found when one of the original lines reached

$$PR_{eq} = \min\left(\frac{PR_1(X_1 + X_2)}{X_2}, \frac{PR_2(X_1 + X_2)}{X_1} \right)$$

its power rating.

The procedure is similar to that for finding the equivalent resistance. Start with any two lines. Determine the equivalent rating. Next, find the equivalent rating of the new equivalence and the next line, and so on through the remaining lines until a single equivalent tie-line was acquired for each interconnection.

If events interior to a control area reduce the capability of a utility to send or receive power, the capacity determined from this method would be overstated. Therefore, when possible, the capacity for power transmission has been updated using OASIS data. Since the SUFG models start from a no-trade case, the Total Transfer Capability (TTC) numbers were used. In cases where TTC varied from day to day, a conservative estimate was used. OASIS data were gathered from all available Indiana utilities, as well as those utilities connected to an Indiana utility. The TTC numbers provide two pairs of numbers for each interconnection, import and export capability as reported by both control areas. Quite often these numbers differ, both by direction of flow and by reporting utility. SUFG used the lowest estimate in each direction.

Note that reactive power flow is not modeled. This simplification is based on the assumption that reactive power support will be provided inside the control area. Reactive power is power that is transferred back and forth between the generator and load or between loads but is not consumed by the load. Since the power is not used, there is no direct cost to the provider. The indirect costs, however, may be substantial. First, when a generator provides reactive power support, the power being transferred back and forth restricts the capacity that could be used to generate active, or real, power. Therefore, the generator cannot generate as much active power, resulting in less opportunity for profit. Second, the transfer of reactive power results in increased real power losses. These losses are largely a function of the distance that the reactive power travels. Hence, it is assumed that the most economic location to generate reactive power is locally in order to minimize losses.

Each equivalent transmission tie-line was assigned a loss coefficient which defines the functional relationship between losses on the line and the square of the power flow through the line. The loss coefficients were determined by the equivalent resistance. The loss coefficient for each of the interconnections which was increased to account for losses from the edge of the control area to the central bus. One half of the typical wheeling loss was used. Thus, the model accounts for increases in losses within the control area which are attributable to wheeling power through the control area. One half of the losses are accounted for on the importing line and one half on the exporting line. The non-linear loss function was approximated using a piecewise linear function.

The flow paths along the equivalent interconnections are determined using a simplified power flow study method. This method, known as a DC power flow, uses a linear approximation of the complex, non-linear equations that govern the actual power flow paths in an electric power system. The DC power flow equations are included as constraints to the model, thus ensuring that the approximate actual power flow paths are used. The power ratings of the equivalent tie-lines are included as additional constraints. Therefore, the model provides a least-cost generation dispatch that represents both actual power flow paths and constraints. As has been pointed out, the power flow constraints can be "turned off," in part or in full, to examine the behavior of the system with and without their effects.

In the current version of the model, only those transmission interconnections involved ECAR or MAIN utilities were included. Thus, those transmission lines that connect two different ECAR/MAIN utilities, along with those that connect ECAR/MAIN utilities to utilities from other regions, are included. For multi-state utilities (partially located in Indiana), the appropriate Indiana operating company is separated from its fellow companies. Therefore, I&M and PSI are separate nodes from AEP and CINergy, respectively, connected to their sister companies by the appropriate transmission line.

APPENDIX H

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

SUFG 1999 Base Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

		Retail Sales							
Year		Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
Hist	1980	16612	12418	22544	556	52130	5546	57676	11284
Hist	1981	16118	12470	22907	572	52067	5581	57648	11235
Hist	1982	19927	13725	22600	696	56948	4875	61823	10683
Hist	1983	19950	13665	23476	626	57717	4795	62511	11744
Hist	1984	20153	14274	24678	674	59779	4938	64717	11331
Hist	1985	19707	14651	24480	653	59491	4889	64380	11030
Hist	1986	20410	15429	23618	610	60067	4958	65024	11834
Hist	1987	21154	16144	24694	617	62609	5185	67794	12218
Hist	1988	22444	16808	26546	633	66431	5557	71988	13447
Hist	1989	22251	17205	27394	661	67511	5815	73326	12979
Hist	1990	22037	17659	28311	650	68657	5085	73742	13775
Hist	1991	24215	18580	28141	629	71564	4470	76034	14403
Hist	1992	22916	18456	29540	619	71532	5675	77207	14209
Hist	1993	25060	19627	31562	511	76760	5909	82669	15103
Hist	1994	25176	20116	33395	507	79193	6253	85446	15198
Hist	1995	26513	20646	33590	510	81260	7255	88514	16294
Hist	1996	26833	20909	34755	567	83064	6634	89698	16184
Hist	1997	26909	21303	35158	552	83922	6740	90662	16596
Hist	1998	27673	22161	36376	539	86749	6980	93729	17168
Frcst	1999	28468	22738	35776	567	87549	7012	94561	16779
Frcst	2000	28783	23271	37079	567	89701	7167	96867	17145
Frcst	2001	29300	23795	37940	567	91602	7320	98922	17514
Frcst	2002	29791	24333	38998	567	93689	7482	101170	17917
Frcst	2003	30280	24815	40004	567	95665	7633	103298	18279
Frcst	2004	30811	25319	40703	567	97400	7779	105179	18620
Frcst	2005	31353	25883	41332	567	99135	7923	107058	18962
Frcst	2006	31823	26471	41914	567	100776	8057	108833	19288
Frcst	2007	32242	27014	42587	567	102411	8190	110601	19604
Frcst	2008	32686	27609	43241	567	104103	8330	112433	19936
Frcst	2009	33154	28139	43827	567	105686	8461	114148	20248
Frcst	2010	33693	28759	44490	567	107509	8615	116124	20614
Frcst	2011	34299	29392	45248	567	109506	8785	118291	21019
Frcst	2012	34813	29959	45864	567	111203	8926	120130	21290
Frcst	2013	35430	30671	46620	567	113289	9100	122389	21703
Frcst	2014	36109	31357	47479	567	115512	9285	124797	22142
Frcst	2015	36696	31917	47824	567	117004	9402	126406	22443
Frcst	2016	37366	32636	48127	567	118696	9541	128237	22789
Average Compound Growth Rates (%)									
Year		Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1980-1985		3.48	3.36	1.66	3.27	2.68	-2.49	2.22	-0.45
1985-1990		2.26	3.81	2.95	-0.09	2.91	0.79	2.75	4.55
1990-1995		3.77	3.17	3.48	-4.74	3.43	7.37	3.72	3.42
1995-2000		1.66	2.42	2.00	2.15	2.00	-0.24	1.82	1.02
2000-2005		1.73	2.15	2.20	0.00	2.02	2.03	2.02	2.04
2005-2010		1.45	2.13	1.48	0.00	1.64	1.69	1.64	1.68
2010-2015		1.72	2.11	1.46	0.00	1.71	1.76	1.71	1.71
2015-2016		1.83	2.25	0.63	0.00	1.45	1.49	1.45	1.54
1996-2016		1.67	2.25	1.64	0.00	1.80	1.83	1.80	1.73

SUFG 1999 Low Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

		Retail Sales							
Year		Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
Hist	1980	16612	12418	22544	556	52130	5546	57676	11284
Hist	1981	16118	12470	22907	572	52067	5581	57648	11235
Hist	1982	19927	13725	22600	696	56948	4875	61823	10683
Hist	1983	19950	13665	23476	626	57717	4795	62511	11744
Hist	1984	20153	14274	24678	674	59779	4938	64717	11331
Hist	1985	19707	14651	24480	653	59491	4889	64380	11030
Hist	1986	20410	15429	23618	610	60067	4958	65024	11834
Hist	1987	21154	16144	24694	617	62609	5185	67794	12218
Hist	1988	22444	16808	26546	633	66431	5557	71988	13447
Hist	1989	22251	17205	27394	661	67511	5815	73326	12979
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Hist	1996	26833	20909	34755	567	83064	6634	89698	16184
Hist	1997	26909	21303	35158	552	83922	6740	90662	16596
Hist	1998	27673	22161	36376	539	86749	6980	93729	17168
Frcst	1999	28468	22733	35768	567	87536	7011	94547	16777
Frcst	2000	28761	23220	36882	567	89431	7144	96575	17095
Frcst	2001	29257	23683	37442	567	90949	7265	98213	17394
Frcst	2002	29717	24140	38195	567	92619	7390	100010	17720
Frcst	2003	30172	24553	38882	567	94175	7505	101680	18006
Frcst	2004	30692	25029	39295	567	95583	7621	103203	18288
Frcst	2005	31187	25453	39566	567	96773	7720	104493	18529
Frcst	2006	31620	25966	39739	567	97892	7810	105703	18759
Frcst	2007	32035	26481	40082	567	99165	7911	107077	19012
Frcst	2008	32460	27012	40431	567	100470	8016	108487	19273
Frcst	2009	32899	27453	40676	567	101595	8108	109703	19501
Frcst	2010	33396	27974	40940	567	102878	8216	111094	19768
Frcst	2011	33974	28560	41281	567	104383	8344	112726	20084
Frcst	2012	34477	29080	41555	567	105679	8449	114128	20283
Frcst	2013	35028	29632	41870	567	107097	8568	115666	20571
Frcst	2014	35659	30261	42239	567	108727	8705	117432	20901
Frcst	2015	36226	30786	42246	567	109825	8789	118614	21132
Frcst	2016	36846	31338	42098	567	110850	8874	119724	21354

Average Compound Growth Rates (%)

Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1980-1985	3.48	3.36	1.66	3.27	2.68	-2.49	2.22	-0.45
1985-1990	2.26	3.81	2.95	-0.09	2.91	0.79	2.75	4.55
1990-1995	3.77	3.17	3.48	-4.74	3.43	7.37	3.72	3.42
1995-2000	1.64	2.38	1.89	2.15	1.93	-0.31	1.76	0.97
2000-2005	1.63	1.85	1.41	0.00	1.59	1.56	1.59	1.62
2005-2010	1.38	1.91	0.69	0.00	1.23	1.25	1.23	1.30
2010-2015	1.64	1.93	0.63	0.00	1.32	1.36	1.32	1.34
2015-2016	1.71	1.79	-0.35	0.00	0.93	0.97	0.94	1.05
1996-2016	1.60	2.04	0.96	0.00	1.45	1.47	1.45	1.40

SUFG 1999 High Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
Hist	1980	16612	12418	22544	556	52130	5546	57676	11284
Hist	1981	16118	12470	22907	572	52067	5581	57648	11235
Hist	1982	19927	13725	22600	696	56948	4875	61823	10683
Hist	1983	19950	13665	23476	626	57717	4795	62511	11744
Hist	1984	20153	14274	24678	674	59779	4938	64717	11331
Hist	1985	19707	14651	24480	653	59491	4889	64380	11030
Hist	1986	20410	15429	23618	610	60067	4958	65024	11834
Hist	1987	21154	16144	24694	617	62609	5185	67794	12218
Hist	1988	22444	16808	26546	633	66431	5557	71988	13447
Hist	1989	22251	17205	27394	661	67511	5815	73326	12979
Hist	1990	22037	17659	28311	650	68657	5085	73742	13775
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Hist	1997	26909	21303	35158	552	83922	6740	90662	16596
Hist	1998	27673	22161	36376	539	86749	6980	93729	17168
Frcst	1999	28472	22742	35782	567	87563	7013	94575	16782
Frcst	2000	28822	23551	37247	567	90187	7206	97393	17239
Frcst	2001	29405	24536	38399	567	92907	7427	100334	17764
Frcst	2002	29970	25544	39782	567	95863	7659	103522	18334
Frcst	2003	30538	26519	41127	567	98751	7884	106635	18871
Frcst	2004	31139	27503	42131	567	101340	8099	109439	19375
Frcst	2005	31732	28549	43013	567	103861	8308	112169	19868
Frcst	2006	32266	29675	43860	567	106368	8514	114882	20360
Frcst	2007	32765	30754	44842	567	108928	8725	117653	20854
Frcst	2008	33267	31882	45779	567	111495	8939	120434	21354
Frcst	2009	33843	33072	46725	567	114208	9162	123370	21885
Frcst	2010	34458	34246	47755	567	117027	9398	126425	22443
Frcst	2011	35164	35541	48872	567	120144	9660	129805	23065
Frcst	2012	35780	36759	49877	567	122983	9893	132877	23557
Frcst	2013	36476	38085	50973	567	126102	10154	136255	24168
Frcst	2014	37218	39423	52126	567	129334	10424	139759	24801
Frcst	2015	37886	40697	52801	567	131951	10636	142588	25318
Frcst	2016	38643	42131	53445	567	134786	10873	145659	25883

Average Compound Growth Rates (%)

Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1980-1985	3.48	3.36	1.66	3.27	2.68	-2.49	2.22	-0.45
1985-1990	2.26	3.81	2.95	-0.09	2.91	0.79	2.75	4.55
1990-1995	3.77	3.17	3.48	-4.74	3.43	7.37	3.72	3.42
1995-2000	1.68	2.67	2.09	2.15	2.11	-0.13	1.93	1.13
2000-2005	1.94	3.92	2.92	0.00	2.86	2.89	2.87	2.88
2005-2010	1.66	3.71	2.11	0.00	2.42	2.50	2.42	2.47
2010-2015	1.91	3.51	2.03	0.00	2.43	2.51	2.44	2.44
2015-2016	2.00	3.52	1.22	0.00	2.15	2.22	2.15	2.23
1996-2016	1.84	3.57	2.17	0.00	2.45	2.50	2.45	2.38

Indiana Base Average Retail Rates (Cents/kWh) (In 1996 Dollars)

Year		Res	Com	Ind	Average
Hist	1980	8.45	8.62	6.21	7.50
Hist	1981	8.66	8.55	6.32	7.57
Hist	1982	9.54	9.03	6.92	8.29
Hist	1983	9.90	9.09	6.97	8.40
Hist	1984	9.99	9.12	6.96	8.41
Hist	1985	10.19	9.11	6.84	8.42
Hist	1986	10.28	9.32	7.00	8.63
Hist	1987	9.89	9.05	6.34	8.15
Hist	1988	9.29	8.60	6.01	7.69
Hist	1989	8.63	7.30	5.45	6.88
Hist	1990	8.09	6.85	5.12	6.43
Hist	1991	7.55	6.40	4.85	6.09
Hist	1992	7.46	6.23	4.70	5.90
Hist	1993	7.00	5.88	4.40	5.55
Hist	1994	7.00	5.85	4.34	5.49
Hist	1995	6.85	5.80	4.15	5.38
Hist	1996	6.81	5.72	4.11	5.31
Hist	1997	7.20	5.62	4.44	5.53
Hist	1998	7.16	5.59	4.40	5.50
Frcst	1999	6.62	5.52	3.88	5.13
Frcst	2000	6.67	5.54	3.89	5.14
Frcst	2001	6.49	5.37	3.82	5.01
Frcst	2002	6.29	5.24	3.72	4.87
Frcst	2003	6.28	5.22	3.71	4.85
Frcst	2004	6.34	5.26	3.72	4.88
Frcst	2005	6.35	5.26	3.71	4.88
Frcst	2006	6.32	5.23	3.69	4.86
Frcst	2007	6.36	5.26	3.70	4.88
Frcst	2008	6.36	5.25	3.68	4.87
Frcst	2009	6.43	5.30	3.71	4.92
Frcst	2010	6.39	5.27	3.69	4.89
Frcst	2011	6.38	5.26	3.68	4.88
Frcst	2012	6.47	5.32	3.71	4.94
Frcst	2013	6.35	5.23	3.66	4.86
Frcst	2014	6.33	5.22	3.66	4.85
Frcst	2015	6.49	5.36	3.80	5.00
Frcst	2016	6.46	5.34	3.79	4.98

Average Compound Growth Rates (%)

Year	Res	Com	Ind	Average
1980-1985	3.81	1.12	1.93	2.34
1985-1990	-4.50	-5.55	-5.62	-5.24
1990-1995	-3.29	-3.25	-4.10	-3.50
1995-2000	-0.54	-0.93	-1.30	-0.91
2000-2005	-0.97	-1.04	-0.93	-1.03
2005-2010	0.14	0.06	-0.12	0.04
2010-2015	0.28	0.32	0.59	0.42
2015-2016	-0.34	-0.36	-0.39	-0.24
1996-2016	-0.26	-0.34	-0.41	-0.31

Notes :

--Energy Weighted Average Rates For Indiana IOUs.
--Results for the 1999 SUFG low and high scenarios are very similiar and are not reported

SUFG 1999 Base Total Demand And Supply (MW) for Indiana

Year	Demand	Capacity	Additions: Peaking	Additions: Cycling	Additions: Base Load	Retired Penalty	Reserve Margin (%)	
1980	11284	14462	0	0	0	0	28.2	
1981	11235	14537	75	0	0	0	29.4	-- SIGECO adds Broadway CT
1982	10683	15669	0	0	1135	0	46.7	-- IMPA, PSI and WVPA add Gibson Unit 5; HEREC adds Merom Unit 2
1983	11744	16506	0	0	993	0	40.5	-- HEREC adds Merom Unit 1; NIPSCO adds Schahfer Unit 17
1984	11331	16639	0	0	533	0	46.8	-- I&M adds Rockport Unit 1
1985	11030	16639	0	0	0	0	50.9	
1986	11834	17678	0	0	1109	70	49.4	-- IPL adds Petersburg Unit 4; IPL retires Stout Units 1-2; NIPSCO adds Schahfer Unit 18; SIGECO adds Brown Unit 2
1987	12218	17678	0	0	0	0	44.7	
1988	13447	17678	0	0	0	0	31.5	
1989	12979	17678	0	0	0	0	36.2	
1990	13775	18442	0	0	596	0	33.9	-- I&M adds Rockport Unit 2; IMPA adds Trimble County Unit 1
1991	14403	18507	0	0	0	0	28.5	
1992	14209	18977	220	0	0	0	33.6	-- IMPA adds Anderson and Richmond CTs; SIGECO adds Brown CT
1993	15103	19128	100	0	0	0	26.6	-- PSI adds Cayuga CT
1994	15198	18885	80	0	0	328	24.3	-- IPL adds Stout CT; I&M retires Breed
1995	16294	19010	80	0	0	11	16.7	-- IPL adds Stout CT
1996	16184	19216	0	143	27	0	18.7	-- PSI adds Wabash River Repowering Project; SIGECO upgrades Culley Unit 3
1997	16596	19084	0	0	0	0	15.0	
1998	17168	19050	0	0	45	0	11.0	-- I&M upgrades Cook Unit 2 (Nuclear)
1999	16779	19520	600	0	0	0	16.3	
2000	17145	20174	300	0	0	0	17.7	-- I&M long-term firm sale expires
2001	17514	20460	350	0	0	0	16.8	
2002	17917	20660	0	200	0	0	15.3	
2003	18279	21190	0	0	500	0	15.9	
2004	18620	21490	300	0	0	0	15.4	
2005	18962	21810	0	0	0	0	15.0	-- I&M long-term firm sale expires
2006	19288	22267	0	0	500	43	15.4	-- NIPSCO retires Mitchell gas turbines 9A-9C
2007	19604	22547	150	0	0	70	15.0	-- HEREC long-term form sale expires; IPL retires Stout Units 3 and 4
2008	19936	23159	0	0	500	88	16.2	-- HEREC long-term firm sale expires; IPL retires Stout gas turbines 1-3; NIPSCO retires Bailly gas turbine 10
2009	20248	23295	0	175	0	39	15.0	-- IPL retires Pritchard Unit 1
2010	20614	23751	150	200	0	99	15.2	-- I&M long-term firm sale expires; IPL retires Pritchard Unit 2; NIPSCO retires Michigan City Unit 2
2011	21019	24323	0	175	500	103	15.7	-- IPL retires Pritchard Unit 3; NIPSCO retires Michigan City Unit 3
2012	21290	24583	125	200	0	0	15.5	
2013	21703	24940	275	200	0	118	14.9	-- IPL retires Pritchard Units 4 and 5
2014	22142	25565	125	0	500	0	15.5	
2015	22443	25812	375	675	0	804	15.0	-- I&M retires Tanners Creek Units 1-4
2016	22789	26287	100	0	500	125	15.3	

A

A Priori Beforehand.

Acid Rain Rainfall occurring when atmospheric water vapor combines with oxides of sulfur and nitrogen (from both man-made and natural sources) to form sulfuric or nitric acid. Natural rainfall is slightly acidic due to the presence of carbon dioxide (CO_2) in the atmosphere which forms a mild carbonic acid. If rainfall becomes too acidic, it may cause environmental damage.

Additions (To Utility Plant)

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

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

Allowance for Funds Used During Construction (AFUDC) Method of capitalizing the cost of money used to build new facilities.

Asset Base Items of value owned by or owed to a business. It represents either a property right or value acquired, or an expenditure made which has created a property right or is properly applicable to the future. Utility assets include: Utility Plant, Other Property and Investments, Current and Accrued Assets and Deferred Debits.

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

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

$$\left[\left[\left(\frac{\text{Value of Year 2016}}{\text{Value of Year 1997}}\right)^{\left(\frac{1}{2016-1997}\right)}\right]-1\right]*100$$

Average Cost The total cost divided by the number of units produced. The average cost method is a method of determining the cost of providing service to the various customer classes. Average cost-of-service figures may be used in setting rates. Average costs are determined with the aid of information gathered in a cost-of-service study. This method of costing, while distinguishing costs between different customer classes, fails to recognize that not all kilowatts and kilowatthours are produced at the same cost within one customer class. For this reason, marginal cost-based rates more accurately reflect the true variable cost of producing the last kilowatthour (See also *Marginal Cost*)

Average Marginal Cost The average, usually weighted by the level of production, of marginal costs incurred at different times or locations.

Avoided Costs The savings in total production costs achieved as a result of reducing total production.

B

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

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

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

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

Base Rate That portion of the total electric rate covering the general costs of doing business unrelated to fuel expenses and other variable operating costs.

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

Building Shell Choice The decisions made in building construction regarding the level and type of insulation, windows, air exchange and so forth.

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

Building Envelope The level and type of building insulation, windows, air exchange, etc. that determine the thermal integrity of the structure.

C

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

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

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

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

Capacity Additions Additions to generating equipment that increase the ability to produce electric energy.

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

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

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

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

Capital Intensive A business condition in which a relatively large dollar investment in plant and equipment is required to produce a unit of revenue. The electric utility industry is one of the most capital intensive of all industries. The ratio of capital investment to annual operating revenues for electric utilities is nearly 3 to 1. That same ratio for an average manufacturing facility is about 0.8 to 1.

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

Class of Service A group of customers with similar characteristics (i.e., residential, commercial, industrial, sales for resale, etc.) which is identified for the purpose of setting a rate for its service.

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

Cogeneration (Cogen) The simultaneous production of electric energy and useful thermal energy for industrial and commercial heating/cooling purposes.

Coincidence The occurrence of two or more demands simultaneously. (See also *Diversity*)

Coincidence Factor The ratio of coincident demand to the sum of the individual demands at a specific time, most commonly at the maximum of coincident peak demand.

Coincident Demand The sum of two or more demands which occurs in the same demand interval.

Collusion Usually this refers to a market strategy by some producers to act cooperatively to increase their joint profit. This can be done explicitly so that they are a cartel. However, if they do not meet to have an agreement on collusion, but act implicitly as a cartel, the strategy is called tacit collusion.

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

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

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

Competitive Bidding A method of purchasing goods or services through a solicitation of bids from competing suppliers. In the electric industry, this term commonly refers to a competitive procurement process for selecting some portions of future electric generating capacity that may include: the publication of a Request for Proposal (RFP) by an electric utility for the purchase of electric generating capacity, electric energy and/or demand-side management products and services; the submission of bids offering to provide such products and services by multiple would be suppliers; and the selection by an electric utility of one or more winning bids, subject to appropriate oversight by a state regulatory commission.

Consumer Price Index A measure of aggregate prices for commodities and services typically purchased by individuals. This index is generally used to gauge the change in average price levels for all commodities. By comparing the change in the price of any commodity to the change in the Consumer Price Index over a period of time, one can estimate the real price change (i.e., the net price change of general inflation in the economy) for that commodity.

Constraint A physical or artificial (such as government policy) condition/boundary that is not allowed to be violated or that must be respected under a normal environment. A typical example is that a power generator is not allowed to produce more power than its rated capacity.

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

Conjectural Variation Model In some cases, producers would like to use production quantity to influence market outcome. However, if one producer uses its production quantity as a means for gaming, it has to speculate how other producers would respond with their production quantities. This speculation of the relative changes of one producer's production quantity change against the quantity changes of the other producers is called conjectural variation. The model used to quantify this speculation is called conjectural variation model.

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

Correlation (also used as **Correlation Coefficient**) A measure of the linear association between two variables, calculated as the square root of the R^2 obtained by regressing one variable on the other. Correlation values range from -1 to +1. Correlation values close to +1 or -1 show a strong linear relationship between the two variables (either directly or inversely proportional, respectively) while correlation values close to zero show almost no relationship between the variables.

Cost of Service A pricing concept traditionally used as the primary basis for designing electric rate schedules. This concept attempts to correlate utility costs and revenues with the service provided to each customer class.

Covariance An unscaled measure of how closely two variables move together across time or space.

Curtailable Rate A rate which is designed to reduce a utility's peak load requirements by offering a customer a substantial rate discount when its service is interrupted during the utility's peak demand period. Programs using these rates are usually targeted at large commercial and industrial customers who pledge a minimum interruptible load level to be curtailed as directed by the utility during electrical emergencies.

Customer Class A group of customers with similar characteristics (i.e., residential, commercial, industrial, sales for resale, etc.) which is identified for the purpose of setting a rate for electric service.

D

Deflator An index which is used to adjust for the purchasing power of a dollar. (See also *Consumer Price Index*)

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

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

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

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

Dependent Variables Variables in a statistical model that are causally influenced by other (explanatory) variable or variables.

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

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

Distributed Lag An econometric modeling approach to represent a response that is delayed and spread over time.

Distribution The act or process of delivering electric energy from convenient points on the transmission or bulk power system to consumers. Also a functional classification relating to that portion of a utility plant used for the purpose of delivering electric energy from convenient points on the transmission system to consumers, or to expenses relating to the operation and maintenance of distribution plant.

Distribution Curve A statistical curve that defines the probability of all events. An example of a distribution curve, commonly used, would be a normal, or bell-shaped curve.

Diversity That characteristic of a variety of electric loads whereby individual maximum demands usually occur at different times. Diversity among customers' loads results in diversity among the loads of distribution transformers, feeders and substations, as well as entire systems. (See also *Coincidence and Load Diversity)*

Dollar Weighted Average An average calculated for a variable by using monetary values as a weight (as opposed to using physical quantities).

E

East Central Area Reliability Coordination Agreement (ECAR) One of nine regional power groups that comprise the North American Electric Reliability Council (NERC). Formed in 1967, ECAR is made up of 28 major bulk suppliers in eight east-central states serving some 36 million people.

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

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

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

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

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

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

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

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

$$WSTK_t = \frac{\sum_i W_i STK_{i,t}}{\sum_i STK_{i,t}}$$

where :

W_i = [Electricity Consumption by Building Type/Floorspace Stock by Building Type i for Some Year, Currently 1989]

$STK_{i,t}$ = [Floorspace Stock for Building Type i and Period t, and is computed/Estimated in the Commercial End-Use Model (CEDMS)]

Electrotechnologies Technologies which depend in some substantial way on electric power.

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

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

End-Use Load Research Load research conducted for electric end-use equipment-specific load. This is done by metering specific usage for individual appliances and machinery.

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

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

Endogenous Variable A variable determined within the system of interest.

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

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

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

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

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

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

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

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

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

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

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

Escalation Rate A factor used to reflect the average increase in price levels in a particular period.

Estimate To calculate approximately the extent or amount of.

Exempt Wholesale Generator (EWG) A wholesale power generator that is exempt from the provisions of the Public Utility Holding Company Act (PUHCA). This legal class of companies was created by the Energy Policy Act of 1992 in order to allow registered public utility holding companies, other corporate entities and individuals to own wholesale generating assets that are leased or sell power to non-affiliates without subjecting the owners to regulation under PUHCA.

Exogenous Variable A variable determined outside the system of interest.

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

Externalities An externality occurs when an entity is engaged in an activity that creates harm or benefits for others as a by-product, but that entity does not pay the costs of, or receive compensation for, the harm or benefits created. It is the absence of payment for the effects on others that distinguishes external impacts from those that are internalized.

F

Federal Energy Regulatory Commission (FERC) An independent agency created within the Department of Energy, FERC is vested with broad regulatory authority. Virtually every facet of electric and natural gas production, transmission and sales conducted by private investor-owned utilities, corporations or public marketing agencies was placed under the commission through either direct or indirect jurisdiction if any aspect of their operations were conducted in interstate commerce. As successor to the former Federal Power Commission (FPC), the FERC inherited practically all of the FPC's interstate regulatory functions over the electric power and natural gas industries.

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

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

Fuel Share Model A Logit model used to determine the choice of space heating fuel in SUFG's econometric residential model.

Functional Category Categories in which the investment and cost of utility plant, i.e., production plant, transmission plant, etc. may be assigned for rate making purposes.

G

Gaming Models In this report, gaming is limited to commercial market gaming. Thus, gaming models are mathematical models for simulating different market gaming strategies.

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

Generating Unit An electric generator together with its prime mover.

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

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

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

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

Gigawatthour (GWh) One gigawatthour equals one billion watthours.

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

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

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

H

Headship Rate The percentage of the population that are heads of households, or equivalent; the inverse of the number of occupants per household.

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

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

Heterogeneity Consisting of dissimilar ingredients.

Holding Company, (Electric Utility) Usually means a Corporation (Parent company) that directly or indirectly owns a majority or all of the voting securities of one or more electric utility companies. As most states do not permit a foreign utility company (i.e., one which operates in another state) to operate within their own boundaries, the holding company type of organization is used to bring into one family, consistent with state law, companies that can best be operated as part of an integrated utility system.

Homogeneity Of the same or a similar kind of nature.

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

I

Implicit Price Deflator The economy's aggregate price index. Defined as the ratio of nominal GNP to real GNP.

Incentive Rate A rate or rate discount that is designed to induce specific actions by customers. For example, utilities in several states give incentive rates to the customers to have their air conditioners controlled.

Independent Variable A variable that is assumed to be determined by forces external to a model and is accepted as given data.

Inelastic This is related to price elasticity of demand in this report. Price elasticity of demand is defined as the ratio of the relative change of demand divided by the relative change of price. If this ratio is greater than -1.0 but less than zero, the demand is said to be inelastic.

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

Innovative Rate A rate schedule with rates above or below the associated costs of providing service to the customer. A promotional rate establishes a pricing level which permits sales to be made which otherwise would not occur.

Input Information fed into a system.

Integrated Resource Planning A process by which utilities and regulatory commission assess the cost of and choose among various resource options. (See also *Least Cost Plan)*

Intermediate Run A period of time sufficient to allow some change in the input utilization in production, but of insufficient length to allow the variation of all inputs, especially capital. (See also *Short Run* and *Long Run)*

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

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

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

Internally Consistent Used to mean logical coherence among things or parts in a system. Emphasis is placed on consistency in macroeconomic forecasting.

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

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

K

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

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

L

Least-Cost Plan A plan describing the mix of generating resources and improvements in the efficient production and use of electricity that will meet current and future needs at the lowest cost to the utility and its ratepayers.

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

Load Duration Curve A graph of the amount of time during a period that electric power demand on a system is at a particular level. Demands usually are ordered and plotted from highest to lowest with hours in the year on the horizontal axis and demand in Kilowatts on the vertical axis. The load duration curve is used in planning an electric system because it indicates how many hours in a year the system must be able to supply each of the varying levels of demand.

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

$$Load\ Factor = \frac{Average\ Demand}{Peak\ Demand} \ X\ 100\% \quad or$$

$$Load\ Factor = \frac{Energy}{Peak\ Demand\ X\ Time} \ X\ 100\%$$

Load Profiles, Hourly A curve on a chart showing power (kilowatts) supplied plotted against time of occurrence, illustrating the varying magnitude of the load during the period covered.

Load Research Analysis of electric usage data to understand customer usage patterns and responses to electric utility initiatives.

Load Shape The time-of-use pattern of resource use over time, such as a daily 24 hour pattern or an annual 8,760 hour pattern.

Load Shape Forecasting Projections of changes in customer usage patterns during different periods in a time interval such as seasonal or hourly.

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

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

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

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

M

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

Market Clearing The matching of the last unit of product a specific seller is willing to sell with the last unit of product a specific purchaser is willing to buy.

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

Market Gaming An opportunist behavior by either the producers or the consumers or both to artificially influence the production, consumption and prices of a market. Usually, producers can use production quantity or price or both as gaming tools. This term is often used against the term of perfect competition in economics such that market price, quantity and the revenues of the different producers are manipulated and are away from the perfect market outcome.

Market Power refers to the capability of any individual consumer of producer to influence market quantity and price that depart from the optimal quantity and marginal cost. A group of consumers or producers or both can establish market power by a collective effort.

Marginal Revenue The revenue received from the sale of the incremental production of a good or service.

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

Mean An average of a series of observations.

Measurement Errors Errors which occur in measuring the data values.

Megawatt (MW) One megawatt equals one million watts.

Megawatthour (MWh) One megawatthour equals one million watthours.

Mill One mill is equal to one-tenth of a cent.

Mix Effect Combined effects of more than one factor.

Money Supply (M2) Currency and demand deposits (checking accounts) and time deposits (savings accounts).

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

N

Naturally Occurring Conservation The reduction in energy consumption due to increases in fuel prices and equipment efficiency.

Nominal An adjective that describes any monetary magnitude measured in current prices. For example, Nominal Total Personal Income is the current dollar value of Total Personal Income through time not adjusted to reflect the general levels of price increase in the economy through time.

Non-Coincident Demand The sum of two or more individual demands which do not occur in the same demand interval. Meaningful only when considering demands within a limited period of time, such as day, week, month, heating or cooling season and usually for no more than one year.

Non-Firm Purchase Power or power-producing capacity supplied or available under a commitment having limited or not assured availability.

Non-Stochastic Error Systematic errors that arise due to the use of inappropriate statistical techniques, independent or dependent variable measurement errors and the specification of erroneous function forms.

Non-Utility Generation Generation by producers having generating plants for the purpose of supplying electric power required in the conduct of their industrial and commercial operations. Generation by mining, manufacturing and commercial establishments and by stationary plants of railroads and railways.

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

O

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

Optimization Procedure A procedure that generates a most effective and/or efficient solution.

P

Payback Requirement Requirement for the sum of the net savings from a project to equal the initial investment in a specific length of time.

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

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

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

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

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

Personal Consumer Expenditure Expenditures by consumers using personal income.

Power Exchange A market institution in which a third party determines electricity market clearing prices by equating the buyers bids with the sellers offers such that the quantity of electricity offered for sale meets the demand for electricity

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

Power Pool Two or more interconnected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements and maintenance programs.

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

Price Index A weighted average of prices in the economy at a given time, divided by the prices of the same goods in a base year. An index used to indicate the change in the average price levels during a particular period.

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

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

Q

Qualifying Facility (QFs) An individual (or corporation) who owns and/or operates a generating facility, but is not primarily engaged in the generation or sale of electric power. QFs are either small power production or cogeneration facilities that qualify under Section 201 of PURPA. (See also Cogeneration.)

R

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

Rate Impact Measure (RIM) Measure of the distribution of equity impacts of DSM programs on non-participating utility ratepayers. From this perspective, a program is cost effective if it results in net benefits for non-participating customers.

Rate of Return The ratio of allowed Operating Income to a specified Rate Base expressed as a percentage.

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

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

Real Gross Domestic Product (RGDP) Real GDP is the figure derived by deflating each component of GDP for the general level of increase in prices in the economy.

Real Gross National Product (RGNP) Real GNP is the figure derived by deflating each component of GNP for the general level of increase in prices in the economy.

Real Gross State Product (RGSP) Real GSP is the figure derived by deflating each component of GSP for the general level of increase in prices in the economy.

Real Personal Income The income received by a person from all sources (interest, wages, transfers) adjusted for the general level of increase in prices in the economy.

Real Wage The monetary value of wages divided by the level of output prices. The real wage measures the payment for a unit of labor in terms of real goods and services.

Rebar Reinforcing rod, commonly used in concrete structures.

Reestimation To estimate the relationship between dependent and independent variables again (possibly using different time intervals and/or more recent data).

Regional Transmission Group (RTG) A voluntary organization of transmission owners, transmission users and other entities interested in coordinating transmission planning, expansion, operation and power usage within a region.

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

Reliability Council -- North American Electric Reliability Council (NERC) A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. NERC consists of ten regional reliability councils and encompasses essentially all the power regional of the contiguous United States, Canada and Mexico.

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

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

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

Restructuring The process of moving from a regulated business environment to a competitive one. (See also *Competition*)

Retail Wheeling An unbundled transmission or distribution service that delivers electric power sold by a third-party directly to end users. This service would allow a retail customer to buy power from someone other than the franchised local utility, but still receive delivery using the power lines of the franchised local utility.

Revenue Requirement The sum total of the revenues required to pay all operating and capital costs of providing service.

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

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

S

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

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

Scarcity Value The difference between the price a consumer is willing to pay for a commodity and the marginal cost of producing the commodity when the demand for the commodity exceeds the available supply.

Scrubber A device that uses a liquid spray to remove aerosol and gaseous pollutant from an air steam. The gases are removed either by absorption or chemical reaction. Solid and liquid particulates are removed through contact with the spray.

Sectorial Classification of Prices and Quantities For this report, commercial, industrial and residential sector prices are based on tariffs (rates) as specified in the various utilities "FERC Form 1: Annual Report of Major Electric Utilities, Licensees and Others," pages 300-301, lines 2 through 5, page 304. Price projections are performed using LMSTM based on data described in Appendix H. The allocation of energy between commercial and industrial demand is based primarily on SIC codes. The exception is SIGECO which does not provide energy by SIC. SUFG, instead, uses the split based on information provided in SIGECO's FERC Form 1. Indiana Michigan Power Company provides the historical data for its commercial and industrial demand for Indiana only. Residential energy calibration data for all utilities is based on FERC Form 1 data.

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

Single-Factor Demand Models A model in which output is projected based on a single factor input.

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

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

Specification Error An error which occurs when the wrong relationship is used to estimate a statistical model.

Spinning Reserve Generation capacity committed at some time in excess of the system load projected for that time period, usually expressed as a percentage of the system load.

Standard Deviation A measure of the dispersion or variability of a variable around the arithmetic average. It is defined as:

$$\sqrt{\frac{\sum_{i=1}^{n}\left(x_i - \bar{x}\right)^2}{n-1}}$$

where:

x_i denotes observations of variable x,

$\bar{x}$ denotes the mean of the observations of variable x; and

n is greater than 1.

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

State Plan A resource expansion plan for the state of Indiana that projects required resource allocations and expenditures to reliably meet projected future electricity demand.

Stochastic Random.

Stochastic Error Difference between the estimated and true model.

Stranded Cost/Stranded Benefit The difference between (1) the revenues that utilities would receive in the future to compensate them for the costs of historical investments and contractual obligations pursuant to regulatory institutions prevailing when the commitments were made, and (2) the revenues that they will receive in the future when generation services are sold in a competitive market. When (1) is greater than (2), the amount is called a stranded cost; conversely, when (2) is greater than (1), it is referred to as a stranded benefit.

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

System Load Impact The effect on a system's annual maximum demand due to items such as DSM.

T

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

Total Resource Cost Test (TRC) Measures the difference between the net present value of the total costs of a DSM program (including costs incurred by the utility and the participant) and the avoided costs (i.e., benefits) of utility supply due to the DSM program. From this perspective, a program is cost effective if the avoided supply costs exceed the total program costs.

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

U

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

Unaffiliated Rural Electric Membership Cooperative (U REMC) A rural electric membership cooperative that is not affiliated with the Indiana Municipal Power Agency (IMPA). (See also *Cooperative, Rural Electric Membership (REMC))*

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

Undiscounted Sum of Operation & Maintenance (O&M) Summation of future projected amounts for operation and maintenance expenses without using a discount factor for the amount in the future years. A discount factor reflects the time value of money.

Unit Emission Rate Amount of air pollutants emitted into a community's atmosphere in amounts per day.

Utilization Factor The ratio of the maximum demand of a system (or part of a system) to the rated capacity of the system (or part of the system) under consideration.

V

Variable Cost The out-of-pocket costs incurred in producing a good or service.

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

W

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

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

Weather-Normalized Projections Energy use or peak demand projections made under the assumption of normal weather patterns over the projection period.

Wellhead Price of Natural Gas The price of natural gas at the source, excluding transportation cost.

Wheeling An electric utility operation wherein transmission facilities of one system are used to transmit power produced by another system.

Winter Peak Demand The greatest load on an electric system during any prescribed demand interval in the winter (or heating) season, usually between December 1 of a calendar year and March 31 of the next calendar year (north of the equator).

World Oil Price The price of crude oil excluding transportation and refining costs.

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LIST OF ACRONYMS

AEP	American Electric Power
AFC	Average Fixed Cost
Btu	British Thermal Unit
CAL-PX	California Power Exchange
CEMR	Center for Econometric Model Research
CG&E	Cincinnati Gas & Electric Company
CAAA	Clean Air Act Amendments
CC	Combined Cycle
CT	Combustion Turbine
CEDMS	Commercial Energy Demand Modeling System
DRI	Data Resources Inc.
DSM	Demand-Side Management
DOE	Department of Energy
ECAR	East Central Area Reliability Coordination Agreement
EMI	Econometric Model of Indiana
EPRI	Electric Power Research Institute
EIA	Energy Information Administration
EPACT	Energy Policy Act of 1992
EUI	Energy Utilization Indices
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GAMS	General Algebraic Modeling System
GWh	Gigawatthours
GDP	Gross Domestic Product
GSP	Gross State Product
HVAC	Heating, Ventilation and Air Conditioning
HELM	Hourly Electric Load Model
HEREC	Hoosier Energy Rural Electric Cooperative, Inc.
ISO	Independent System Operator
IBRC	Indiana Business Research Center
INDEPTH	Industrial End-Use Planning Methodology
I&M	Indiana Michigan Power Company
IMPA	Indiana Municipal Power Agency
IUPUI	Indiana University Purdue University, Indianapolis
IURC	Indiana Utility Regulatory Commission
IPL	Indianapolis Power & Light Company
INFORM	Industrial End-Use Forecast Model
IRP	Integrated Resource Plan
IOU	Investor-Owned Utility
kW	Kilowatt
kWh	Kilowatthours
LMSTM	Load Management Strategy Testing Model
MC	Marginal Cost
MCP	Market Clearing Price
MW	Megawatt
MWh	Megawatthours
MAIN	Mid-American Interconnected Network
MAPP	Mid-Continent Area Power Pool
mmBtu	Million British Thermal Unit
M2	Money Supply
MUNY	Municipality
NO_x	Nitrogen Oxides
NUG	Non-Utility Generator
NERC	North American Electric Reliability Council
NIPSCO	Northern Indiana Public Service Company
NFP	Not-for-Profit
ORNL	Oak Ridge National Labs
OASIS	Open Access Sametime Information System
O&M	Operation and Maintenance
OPEC	Organization of Petroleum Exporting Countries
PJM	Pennsylvania-Jersey-Maryland Power Pool
PX	Power Exchange
PSI Energy	PSI Energy, Inc.
PC	Pulverized Coal-Fired
REEMS	Residential End-Use Energy Modeling System
REMC	Rural Electric Membership Cooperative
RUS	Rural Utilities Service
SIPC	Southern Illinois Power Company
SIGECO	Southern Indiana Gas & Electric Com pany
SIC	Standard Industrial Classification
SUFG	State Utility Forecasting Group
SO_2	Sulfur Dioxide
TAG	Technical Assistance Guide
REEMS	Technology-Based End-Use Energy Modeling System
TELPLAN	Total Electric Planning Model
TTC	Total Transfer Capability
T&D	Transmission and Distribution
U MUNY	Unaffiliated Municipality
U REMC	Unaffiliated Rural Electric Membership Cooperative
WVPA	Wabash Valley Power Association

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