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2025 Forecast

INDIANA ELECTRICITY PROJECTIONS

State Utility Forecasting Group

West Lafayette, Indiana
December 2025

Indiana Electricity Projections:
The 2025 Forecast

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Foreword

This report presents the 2025 projections of future electricity requirements for the state of Indiana for the period 2024-2043. This study is part of an ongoing independent electricity forecasting effort conducted by the State Utility Forecasting Group (SUFG). SUFG was formed in 1985 when the Indiana legislature mandated a group be formed to develop and keep current a methodology for forecasting the probable future growth of electricity usage within Indiana. The Indiana Utility Regulatory Commission contracted with Purdue and Indiana Universities to accomplish this goal. SUFG produced its first set of projections in 1987 and has updated these projections periodically. This is the twentieth set of projections.

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

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

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

SUFG has maintained a similar format for this report as was used in recent reports to facilitate comparisons. With the exception of the upgrades described in Chapter 2, details on the operation of the modeling system are limited; for more detailed information, the reader is asked to contact SUFG directly or to look back to the 1999 forecast that is available for download from the SUFG website located at:

http://www.purdue.edu/discoverypark/SUFG/

The authors would like to thank the Indiana utilities, consumer groups and industry experts who contributed their valuable time, information, and comments to this forecast. Also, the authors would like to gratefully acknowledge the Indiana Utility Regulatory Commission for its support, input, and suggestions. Special thanks to Dr. Douglas Gotham for many insightful conversations.

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

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Chapter 1

Summary

Overview

In this report, the State Utility Forecasting Group (SUFG) provides its twentieth set of projections of future electricity usage, peak demand, prices, and resource requirements for 2024-2043. There are four scenarios presented:

- 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.
- The *data center scenario* is new to the 2025 forecast and incorporates estimates of future data center loads layered on top of the *base scenario*.

The base projections in this forecast grow more rapidly than in the 2023 forecast, however, the level of the forecast is lower until the last several years and generally closer to the 2021 forecast for the first half.

This base forecast projects electricity usage to remain relatively flat through 2029, then grow through the remainder of the forecast period, with overall growth at a rate of 1.03 percent per year over the 20 years of the forecast. Peak electricity demand is projected to follow a similar pattern with overall growth at an average rate of 0.61 percent annually. This corresponds to about 128 megawatts (MW) of increased peak demand per year.

The 2025 base forecast predicts Indiana electricity prices to continue to rise in real (inflation-adjusted) terms from 2024 to 2034 and then level off and slightly decline until the end of the forecast period. Several factors determine the price projections. These include costs associated with future resources required to meet future load, costs associated with continued operation of existing infrastructure, and fuel costs. Costs are included for the transmission and distribution of electricity in addition to production.

This base forecast indicates that additional resources are needed throughout the forecast period except for 2027-2028. Additional resource needs in the first half of the forecast are driven by the need for replacement capacity for units that will be retiring in that time. Additional resource needs in the second half of the forecast are driven by both retirements of existing units and increasing demand. The Aurora optimization program may add more new resources than what is strictly necessary to meet the seasonal reserve requirements in some years if it finds it economic to do so. This forecast indicates a need for a mix of natural gas-fired combustion turbines and combined cycle units, wind, and solar capacity. Wind and solar resources are added first, while natural gas is not added until 2029. Wind is added throughout the forecast and additional solar is selected late in the period. While no battery storage or hybrid solar/battery resources were selected in the final forecast run, some were selected in earlier iterations. Nuclear small modular reactors were never selected. In the long term, the projected required additional resources are lower than in the previous forecast, due to more IURC-approved resources being added during the forecast period and fewer scheduled retirements of existing units, as well as lower sales and peak demand projections for most of the forecast period.

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

SUFG has constructed alternative low and high economic growth scenarios. These low probability scenarios are used to indicate the forecast range, or dispersion of possible future trajectories. The annual growth rates for the base, low and high scenarios are 1.03, 0.73, and 1.22, respectively. These differences are driven by economic growth assumptions in the scenario-based projections and differences in assumed growth of electric vehicles. The trajectories for peak demand in the low and high scenarios are similar to the electricity requirements trajectories.

SUFG also prepared a data center scenario as part of the 2025 forecast in light of the significant interest in the state currently surrounding data centers and their potential to dramatically impact required resources. This data center scenario focuses on estimates of future data center additions, particularly the large hyperscalers, but it should be noted that Indiana already has smaller data centers that are effectively included in the base forecast (and low and high). The total aggregated amount of new data center load included in the data center scenario dramatically increases the Indiana energy required and peak demand. The annual growth rates for energy requirements and peak demand in the data center scenario are significantly higher than in the base scenario.

Significantly larger amounts of natural gas resources are selected in the data center scenario than in the base scenario and fewer renewable resources; wind is still maximized, but the build limit is reached much earlier than in the base and no solar is selected in this scenario unlike in the base.

The full details of the data center scenario are presented in Chapter 3, but it is important to note here that there is considerable uncertainty around the data center load amounts SUFG modeled in this scenario.

Outline of the Report

The current forecast includes projections of electric energy requirements, peak demand, prices, and capacity requirements. It also provides projections for each of the three major customer sectors: residential, commercial, and industrial. Chapter 2 of the report briefly describes SUFG's forecasting methodology, including changes made from previous forecasts. Chapter 3 presents the projections of statewide electricity demand, resource requirements, and price. Chapter 4 describes the data inputs and Chapters 5 through 7 present integrated projections for each major consumption sector in the state. Finally, an Appendix depicts the data sources used to produce the forecast and provides historical and forecast data for energy, peak demand, and prices.

The Regulated Modeling System

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

To determine future resource requirements, SUFG has historically used individual utility reserve margins that reflect the planning reserve requirements of the utility's regional transmission organization (RTO) to determine the seasonal reserve requirements. The combination of changing to a seasonal construct in the previous forecast and now incorporating MISO's Direct Loss of Load (DLOL) methodology in the current forecast led SUFG to make the decision to model all the utilities this time as if they are members of MISO[1].

DLOL is not implemented until the 2028-2029 MISO planning year, therefore, there are now two sets of reserve margin targets modeled; before and after DLOL. Applying the individual reserve requirements and adjusting for peak load diversity[2] among the utilities provides a statewide reserve requirement prior to DLOL of 17.9 percent for summer, 27.1 percent for fall, 41.6 percent for winter, and 41.6 percent for spring. Once DLOL is implemented, the targets are 11.8 percent for summer, 20.9 percent for fall, 36.1 percent for winter, and 33.7 percent for spring. This requirement is based on the installed capacity value of the resources, with a modification for the capacity credit for intermittent resources.

Major Forecast Assumptions

In updating the modeling system to produce the current forecast, new projections were developed for all major exogenous variables. A summary of these assumptions follows.

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 2025 projections for its base scenario. A major input to CEMR's Indiana model is a projection of total U.S. employment, which is derived from CEMR's model of the U.S. economy. The CEMR Indiana projections are based on a national employment projection of 0.68 percent growth per year over the forecast period. Indiana total employment is projected to grow at an average annual rate of 0.60 percent.

Other key economic projections from CEMR are:

- Real personal income (a residential sector model driver) is expected to grow at a 1.69 percent annual rate.
- Non-manufacturing employment (the primary commercial sector model driver) is expected to average a 0.79 percent annual growth rate over the forecast horizon.

[1] SUFG analysis showed that treating all utilities as MISO members made no significant difference in the summer season and very little difference in other seasons.
[2] Load diversity occurs because the peak demands for all utilities do not occur at the same time. SUFG estimates the amount of load diversity by analyzing the actual historical load patterns of the various utilities in the state.

- Manufacturing gross state product (GSP) (the primary industrial sector model driver) is expected to rise at a 1.83 percent real annual rate.

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

The data center scenario is layered onto the base scenario; therefore, it uses the same economic forecast as the base forecast. CEMR's economic projections (base, low, and high) do not explicitly account for the potential impacts of data center developments. The rapid and unpredictable pace of data center expansion makes it challenging to capture these impacts within conventional economic activity projections.

Demographic Projections

The projection for population growth in Indiana is 0.17 percent per year. This projection is from the Indiana Business Research Center (IBRC) at Indiana University. The SUFG forecasting system includes a housing model that utilizes population and income assumptions to project the number of households. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of 1.21 percent over the forecast period.

Fossil Fuel Price Projections

SUFG's current assumptions are based on the May 2025 projections produced by the Energy Information Administration (EIA) for the East North Central Region. SUFG's fossil fuel real price projections are as follows:

Utility Natural Gas Prices: Natural gas prices are projected to gradually increase from slightly more than $2/mmBtu in 2024 to around $4/mmBtu in 2035. Prices are expected to remain flat at that level through 2043.

Utility Price of Coal: Coal price projections are relatively flat in real terms throughout the entire forecast horizon (around $2/mmBtu) as coal consumption decreases due to more natural gas and renewable generation observed in the electric power sector.

The Base Scenario

Figure 1-1 shows the current base scenario projection for electricity requirements in gigawatt-hours (GWh), along with the projections from the previous two forecast reports. Similarly, the base projection for peak demand in MW is shown in Figure 1-2. The annual growth rate for electricity requirements in this forecast is 1.03 percent, while the growth rate for peak demand is 0.61 percent. The growth rates in the 2023 forecast for electricity requirements and peak demand were 0.51 and 0.40 percent, respectively. The 2025 forecast grows more rapidly than the previous one, however, the level of the forecast is lower until the last several years and this pattern can be seen in the residential, commercial, and industrial sectors. The lower sales forecasts are driven by a number of factors that are offsetting generally higher economic projections and lower utility-sponsored energy efficiency during that time. The residential and industrial sectors start from a noticeably lower level in the previous forecast. Projected electricity prices are higher than in the previous forecast and rise until 2034 before they level off and slightly decline. These higher electricity prices are putting downward pressure on demand. The electric vehicle forecast in the first part of the forecast is lower than in the previous one due to an improvement in identifying and removing non-plug-in vehicles from the stock of total electric vehicles. The late growth that begins around 2034 is driven by flattening and slightly declining electricity prices as well as significantly higher electric vehicle projections than in the previous forecast.

Table 1-1 shows the growth rates by sector for the current and previous two forecasts. Higher growth is seen in all sectors, but particularly in residential and industrial. See Chapters 5, 6, and 7 for discussions of the forecast growth in the residential, commercial, and industrial sectors.

The growth in peak demand is also higher than in the 2023 forecast. The projections of peak demand are for normal weather patterns. Another measure of peak demand growth can be obtained by considering the year-to-year MW load change. In Figure 1-2, the annual increase is about 128 MW.

Table 1-1. Annual Electricity Sales Growth (Percent) by Sector (Current Forecast vs. 2023 and 2021 Projections)

Sector	Current (2024-2043)	2023 (2022-2041)	2021 (2020-2039)
Residential	1.81	1.28	0.61
Commercial	0.05	-0.19	-1.02
Industrial	0.85	0.20	0.53
Total	1.03	0.51	0.20

Resource Implications

SUFG's resource plans include both demand-side and supply-side resources to meet forecast demand. Utility-sponsored energy efficiency is netted from the demand projection and supply-side resources are added as necessary to maintain the seasonal reserve margins. Demand response loads are treated as an existing resource that can be called on to meet the peak load.

Demand-Side Resources

The current projection includes the energy and demand impacts of existing or planned utility-sponsored energy efficiency programs. Incremental EE programs, which include new programs and the expansion of existing programs, are projected to reduce peak demand by approximately 120 MW at the beginning of the forecast period and by about 1,200 MW at the end of the forecast. Energy efficiency projections were estimated from utility integrated resource plan filings and from information collected directly from the utilities by SUFG.

These energy efficiency projections do not include the demand response loads, which are projected to decline from about 1,000 MW in 2024 to about 680 MW in 2025 before increasing again to about 960 MW by 2040. See Chapter 4 for additional information about utility-sponsored energy efficiency and demand response.

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

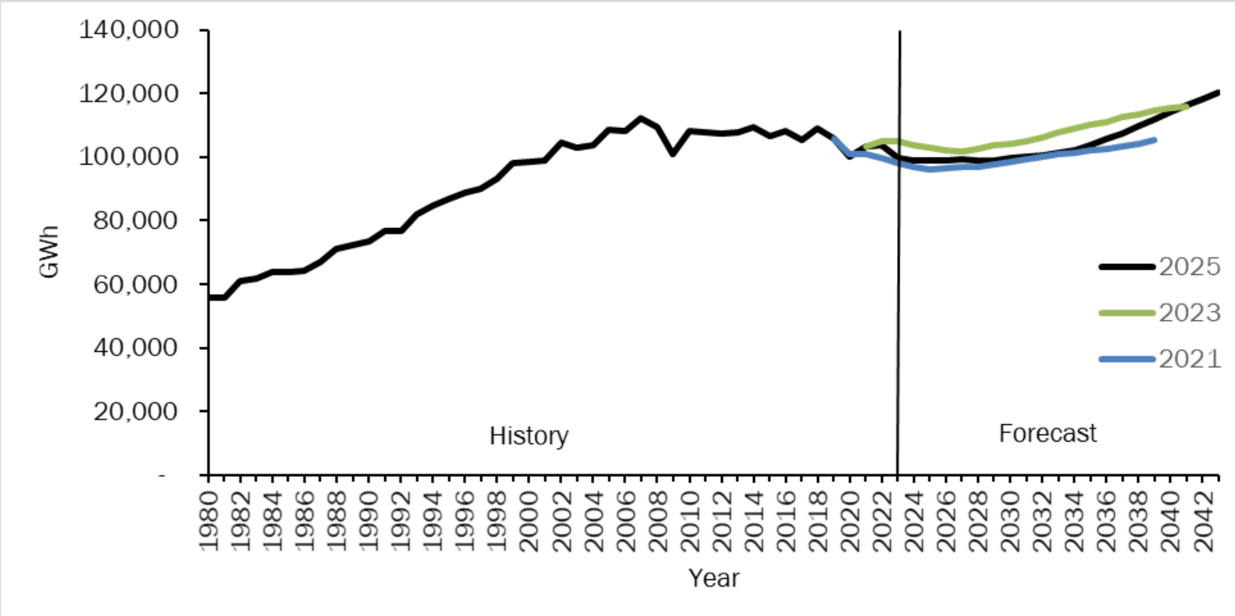
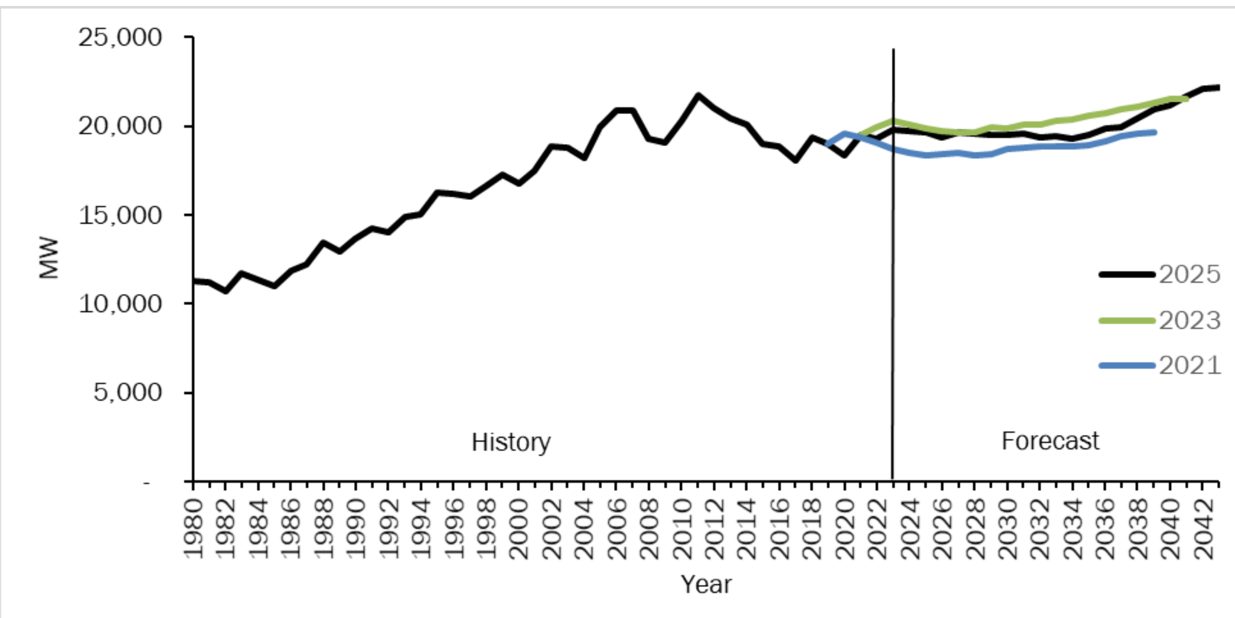


Figure 1-2. Indiana Peak Demand Requirements in MW (Historical, Current, and Previous Forecasts)



Supply-Side Resources

SUFG's base resource plan includes all planned capacity changes at the time the model inputs were finalized[3]. Planned capacity changes include: certified, rate base eligible generation additions,

[3] The inputs to the model were finalized in the summer of 2025. As of the time that this report was published, 2,346 MW of additional natural gas resources have been approved by the IURC. Additionally, 744 MW of additional wind PPAs have been approved by the IURC with another 268 MW currently pending approval. The

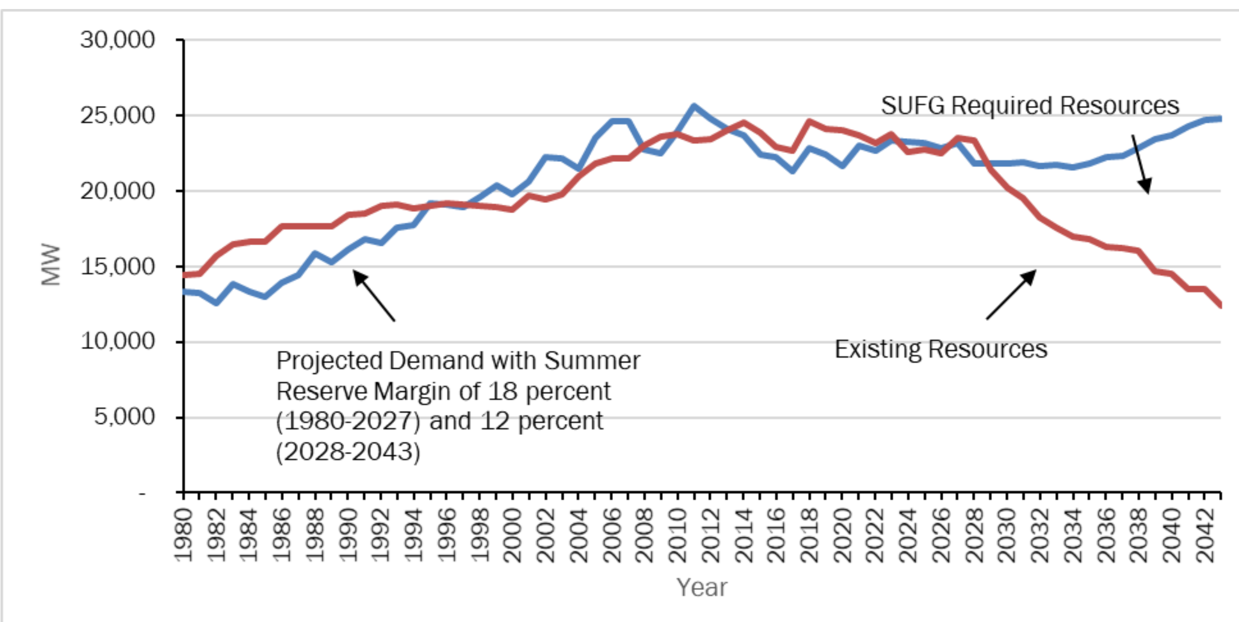
retirements, de-ratings due to pollution control retrofits, changes in the amount of demand response that is available, and net changes in firm out-of-state purchases and sales. SUFG does not attempt to forecast long-term out-of-state contracts other than those currently in place. Generic new generation resources are then selected by a resource planning optimization model to find the lowest cost of meeting demand while meeting the seasonal reserve margins.

Resource Needs

Figure 1-3 and Table 1-2 show the statewide resource plan for the SUFG base scenario.

This forecast indicates that additional resources are needed throughout the forecast period except for 2027-2028. Additional resource needs in the first half of the forecast are driven by the need for replacement capacity for units that will be retiring in that time. Additional resource needs in the second half of the forecast are driven by both retirements of existing units and increasing demand. The Aurora optimization program may add more new resources than what is strictly necessary to meet the seasonal reserve requirements in some years if it finds it economic to do so. This forecast indicates a need for a mix of natural gas-fired combustion turbines and combined cycle units, wind, and solar capacity. Wind and solar resources are added first, while natural gas is not added until 2029. Wind is added throughout the forecast and additional solar is selected late in the period. While no battery storage or hybrid solar/battery resources were selected in the final forecast run, some were selected in earlier iterations. Nuclear small modular reactors were never selected. In the long term, the projected required additional resources are lower than in the previous forecast, due to more IURC-approved resources being added during the forecast period and fewer scheduled retirements of existing units, as well as lower sales and peak demand projections for most of the forecast period.

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



impact of the approved natural gas and wind resources would be to reduce or defer some of the resource additions selected by Aurora. The resources still pending approval would have the same effect, if approved.

Due to data availability restrictions at the time that SUFG prepared the modeling system to produce this forecast, the most current year with a complete set of actual historical data was 2023. Therefore, 2024 and 2025 numbers represent projections.

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

Year	Peak Demand[1]	Existing/ Approved Resources[2]	Incremental Change in Resources[3]	Required Additional Resources[4]	Additional Selected Resources[5]						
					CT	CC	Wind	Solar[6]	BESS[6]	SMR	Total
2024	19,720	22,586		668	0	0	1,691	780	0	0	2,471
2025	19,666	22,729	144	461	0	0	1,691	780	0	0	2,471
2026	19,379	22,464	-266	388	0	0	1,918	780	0	0	2,699
2027	19,639	23,527	1,064	0	0	0	1,918	780	0	0	2,699
2028	19,546	23,379	-148	0	0	0	1,918	780	0	0	2,699
2029	19,493	21,373	-2,007	425	0	775	1,918	780	0	0	3,474
2030	19,502	20,214	-1,158	1,593	0	1,093	3,923	780	0	0	5,797
2031	19,597	19,557	-657	2,356	0	1,669	4,908	780	0	0	7,358
2032	19,353	18,247	-1,310	3,393	0	3,571	5,907	780	0	0	10,259
2033	19,419	17,554	-693	4,160	0	3,571	6,684	780	0	0	11,036
2034	19,285	16,953	-601	4,612	0	3,875	7,173	780	0	0	11,828
2035	19,485	16,823	-130	4,965	0	4,209	7,603	780	0	0	12,593
2036	19,884	16,329	-494	5,905	0	4,995	8,644	780	0	0	14,420
2037	19,957	16,185	-143	6,131	0	5,185	9,255	780	0	0	15,220
2038	20,414	16,081	-104	6,746	0	6,283	9,466	780	0	0	16,530
2039	20,956	14,658	-1,423	8,775	0	7,750	10,535	780	0	0	19,065
2040	21,150	14,530	-128	9,119	0	7,981	12,000	780	0	0	20,761
2041	21,683	13,533	-997	10,713	180	9,270	12,000	2,566	0	0	24,017
2042	22,068	13,464	-69	11,213	180	9,836	12,000	2,566	0	0	24,582
2043	22,155	12,350	-1,114	12,424	288	11,004	12,000	2,566	0	0	25,859

1 Peak demand reflects utility-sponsored energy efficiency programs but is not adjusted for demand response loads.
2 Existing/approved resources include installed capacity plus approved new capacity plus demand response plus firm purchases minus firm sales.
3 Incremental change in resources is the change in existing/approved resources from the previous year. The change is due to new, approved capacity becoming operational, retirements of existing capacity, changes in available demand response loads, and changes in firm purchases and sales.
4 Required additional resources represent the amount of additional resources that are needed to meet the target statewide reserve margin.
5 Additional selected resources are the cumulative amount of additional resources chosen by the optimization model to meet future demand at least cost.
6 The Solar and BESS columns include any amounts from hybrids that were selected.

Equilibrium and Price Impact

Real prices are projected to increase by 52 percent from 2024 to 2034 and then level off and slightly decline until the end of the forecast period. While prices are affected by a number of different factors, the change in prices early in the forecast results primarily from the significant capital investment in transmission, distribution, and newly approved generation that is modeled in the first few years. The earlier expiration of tax credits due to the One Big Beautiful Bill Act (OBBBA) is a contributing factor as well.

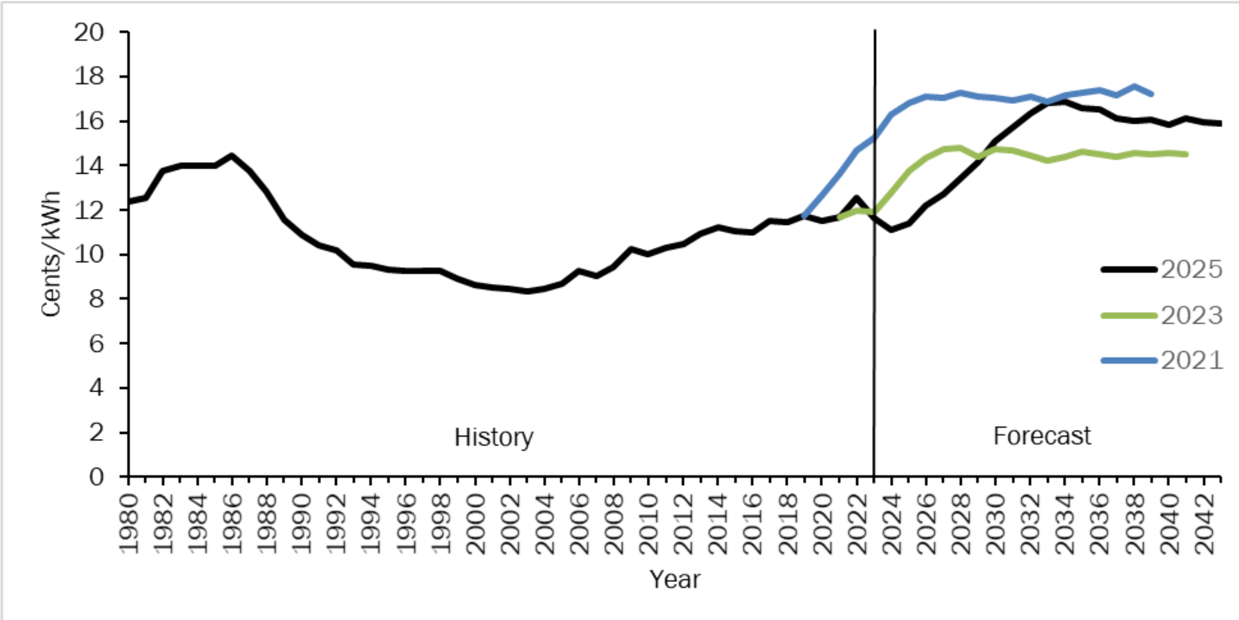
The price increase is significant and higher than in the previous forecast while closer to the 2021 forecast. This affects the electricity requirements projection for this portion of the forecast period. Electricity prices are an input to the forecasting models, so the price increases in the early years cause projected sales to decrease. In turn, this can cause further price increases if sales decline more than revenue requirements.

SUFG's equilibrium price projections for two previous forecasts are also shown in Figure 1-4. The price projection labeled "2021" is the base case projection from SUFG's 2021 forecast report and the one labeled "2023" is the base case projection from SUFG's 2023 report. For the prior price forecasts, SUFG rescaled the original price projections to 2023 dollars (from 2019 dollars for the 2021 projection, and from 2021 dollars for the 2023 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

A number of factors determine the price projections in Figure 1-4. These include costs associated with future resources required to meet future load, costs associated with continued operation of existing infrastructure, and fuel costs. Costs are included for the transmission and distribution of electricity in addition to production. SUFG's 2025 forecasts assume that the greenhouse gas emissions restriction for fossil-fueled electric generating units under Section 111 of the Clean Air Act goes away[4]. Environmental rules, aside from the aforementioned one, that are in place at the time the forecast was prepared are included, while proposed and potential future rules are not.

[4] SUFG tested an alternative version of the base forecast in which capacity factor limits were applied to new gas builds (40% for CC; 20% for CT) in order to capture Clean Air Act section 111 (b). The results were that fewer megawatts of natural gas resources were selected while more renewable resources were selected, as expected.

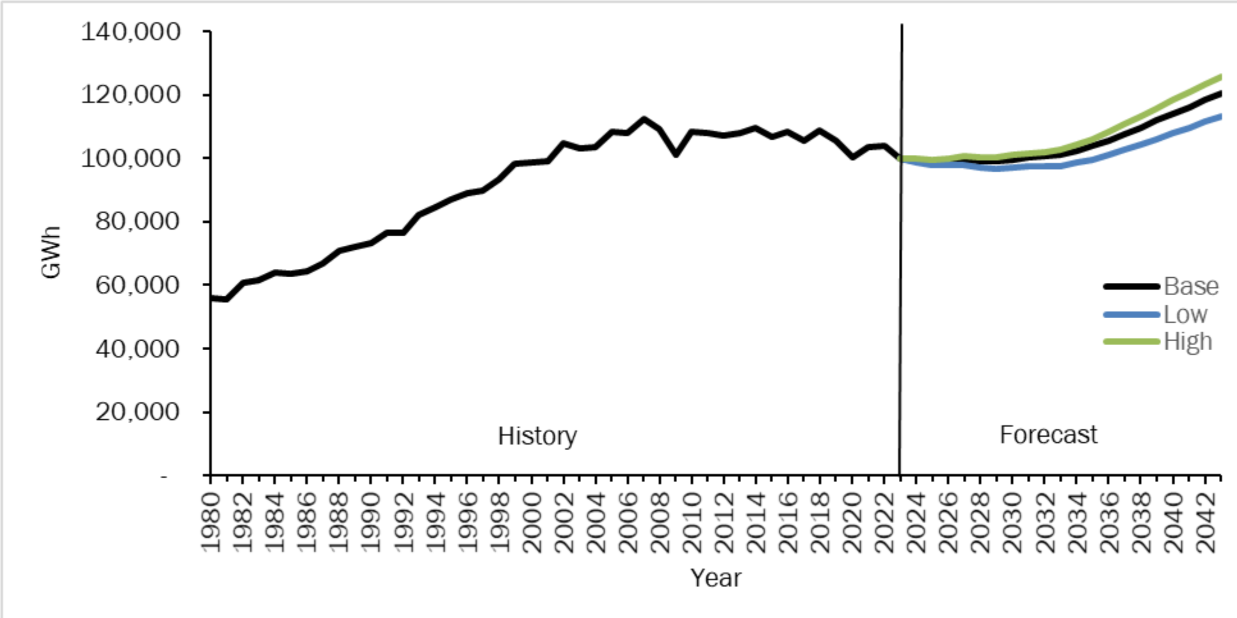
Figure 1-4. Indiana Real Price Projections in cents/kWh (2023 Dollars) (Historical, Current, and Previous Forecasts)



Low and High Scenarios

SUFG has constructed alternative low and high economic growth scenarios. These low probability scenarios are used to indicate the forecast range, or dispersion of possible future trajectories. Figure 1-5 provides the statewide electricity requirements for the base, low and high scenarios. The annual growth rates for the base, low and high scenarios are 1.03, 0.73, and 1.22, respectively. These differences are driven by economic growth assumptions in the scenario-based projections and differences in assumed growth of electric vehicles. The trajectories for peak demand in the low and high scenarios are similar to the electricity requirements trajectories.

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



Data Center Scenario

SUFG prepared a data center scenario as part of the 2025 forecast in light of the significant interest in the state currently surrounding data centers and their potential to dramatically impact required resources. This data center scenario focuses on estimates of future data center additions, particularly the large hyperscalers, but it should be noted that Indiana already has smaller data centers that are effectively included in the base forecast (and low and high).

SUFG is not independently forecasting data center load, but rather layering on amounts provided by the utilities through confidential data requests and in some cases the utilities' Integrated Resource Plan (IRP) presentations (see Chapter 3 for more details).

The total aggregated amount of data center load included in the data center scenario dramatically increases the Indiana energy required and peak demand as can be seen in Figure 1-6 and Figure 1-7. There is considerable uncertainty around the data center amounts SUFG modeled in this scenario.

Figure 1-6. Indiana Energy Required (GWh) Base Scenario vs. Data Center Scenario

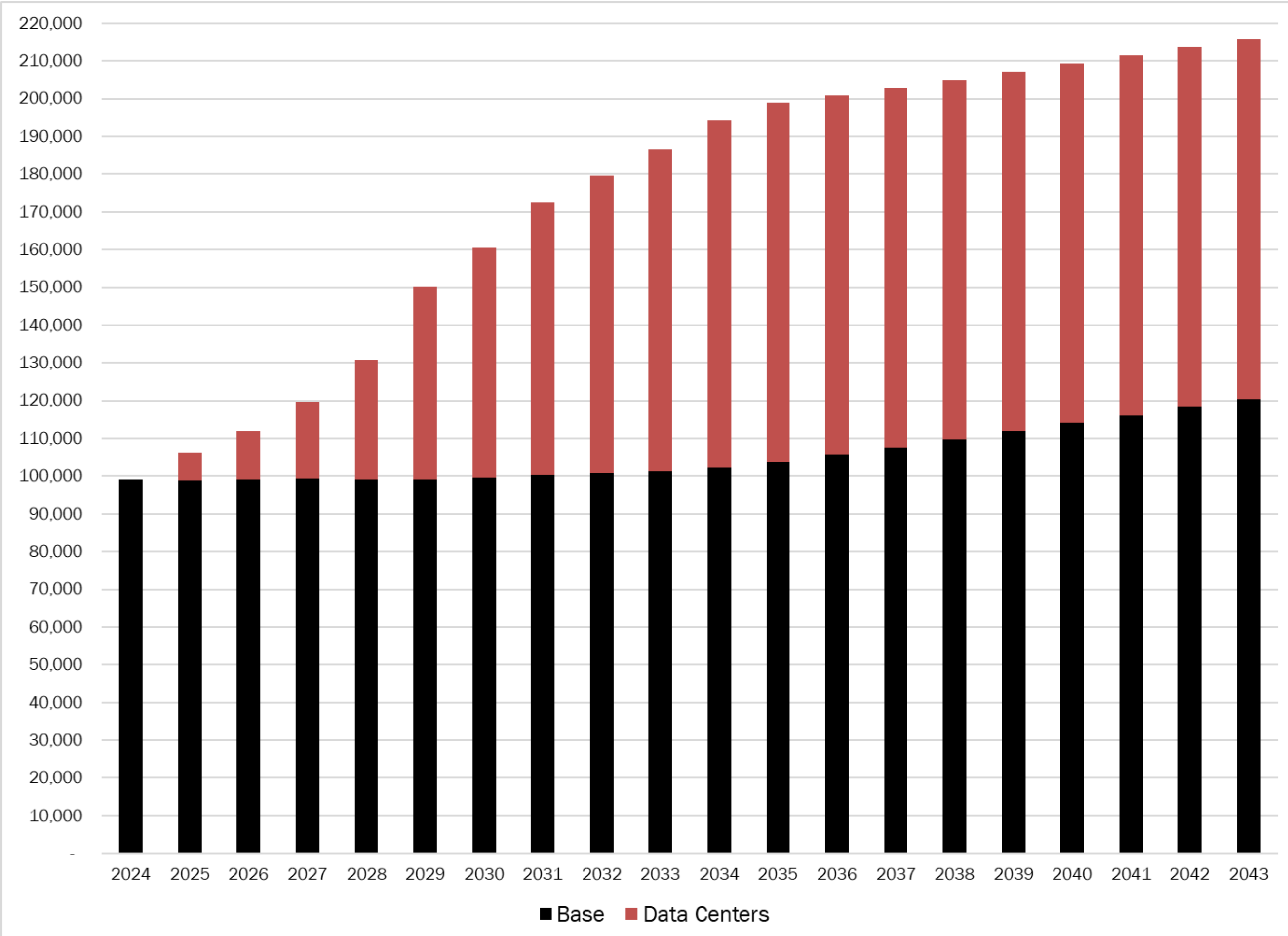
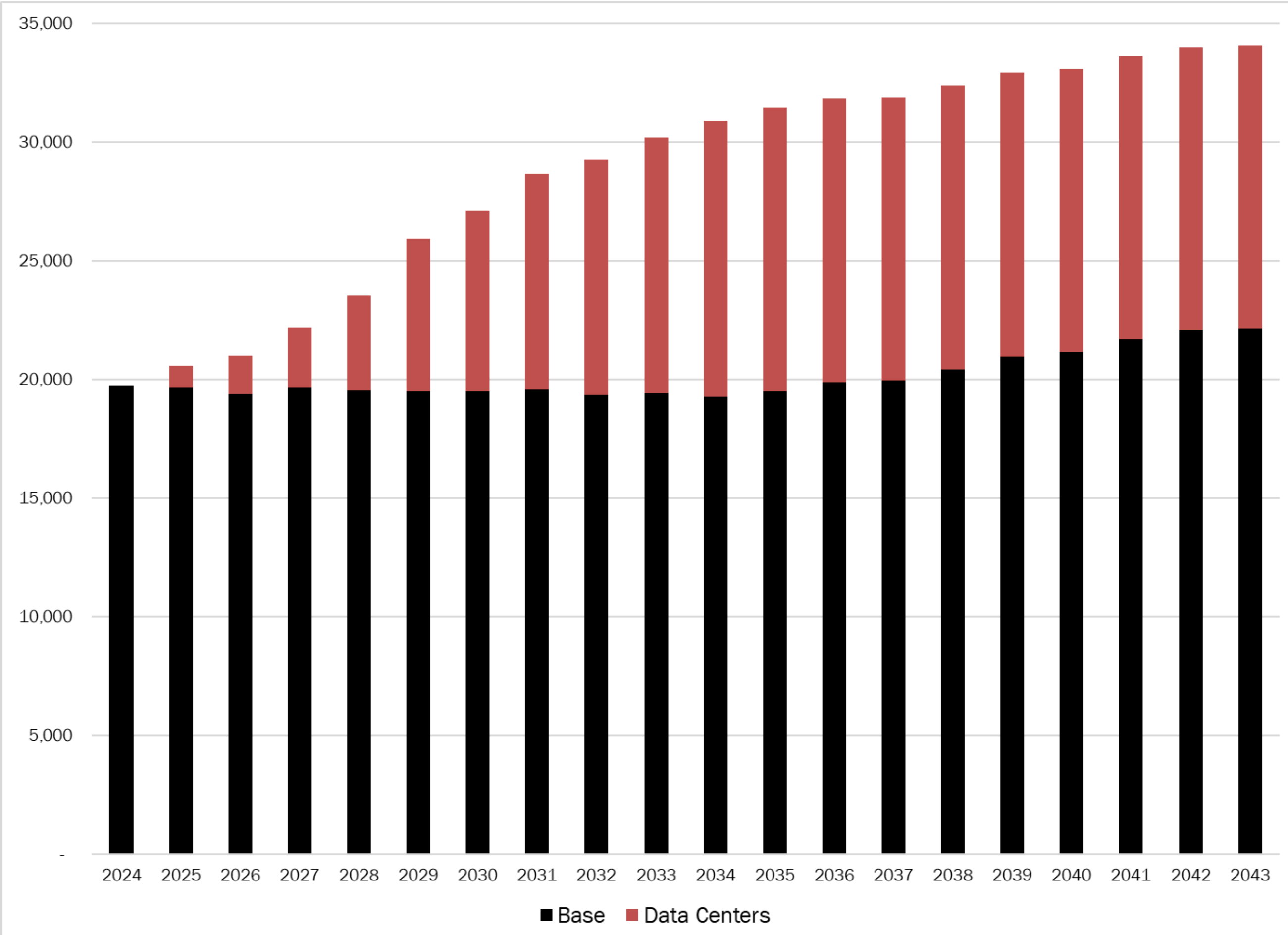


Figure 1-7. Indiana Peak Demand (Summer) (MW) Base Scenario vs. Data Center Scenario



The data center loads were layered onto the base forecast and then run through the Aurora model in order to obtain a revised resource build. Table 1-3 shows the statewide resource plan for the data center scenario. The model selected a significantly larger amount of natural gas resources than in the base scenario and fewer renewable resources; wind is still maximized, but the build limit is reached much earlier than in the base and no solar is selected in this scenario unlike in the base. The wind build limit was kept the same in order to facilitate a direct comparison to the base forecast. Relaxing that constraint would likely increase the amount of wind built and therefore reduce the amount of natural gas resources selected somewhat.

Indiana Michigan Power (I&M) and Northern Indiana Public Service Company (NIPSCO) currently have the largest amount of modeled data centers in the state. I&M received approval from the IURC in February 2025 for the large load tariff settlement filed in late 2024. This tariff structure allows I&M to meet the load growth from data centers while protecting other customers from the costs of serving that load. NIPSCO obtained approval from the IURC in September 2025 to establish a subsidiary called GenCo that will provide power to data centers. The purpose of this structure, similar to what I&M accomplishes through their large load tariff, is to allow NIPSCO to meet the growth due to data centers while also protecting other customers from those costs. NIPSCO intends to purchase the power to serve the data centers through a power purchase agreement (PPA) with GenCo. It should be noted, however, that the resource build in SUFG's data center scenario shown in Table 1-3 includes resources built by NIPSCO since the details of the actual PPA are not known at this time.

Table 1-3. Indiana Selected Resources for Data Center Scenario in MW

Year	Data Center Scenario						
	CT	CC	Wind	Solar	BESS	SMR	Total
2024	0	0	5,290	0	0	0	5,290
2025	0	564	5,290	0	0	0	5,854
2026	0	1,860	5,290	0	0	0	7,150
2027	0	2,882	5,290	0	0	0	8,172
2028	0	2,929	8,359	0	0	0	11,289
2029	0	6,957	12,000	0	0	0	18,957
2030	0	8,867	12,000	0	0	0	20,867
2031	0	11,261	12,000	0	0	0	23,261
2032	0	15,034	12,000	0	0	0	27,034
2033	0	15,163	12,000	0	0	0	27,163
2034	0	17,140	12,000	0	0	0	29,140
2035	0	17,999	12,000	0	0	0	29,999
2036	0	18,238	12,000	0	0	0	30,238
2037	0	18,639	12,000	0	0	0	30,639
2038	86	20,811	12,000	0	0	0	32,897
2039	367	21,286	12,000	0	0	0	33,654
2040	559	21,575	12,000	0	0	0	34,133
2041	826	22,181	12,000	0	0	0	35,007
2042	826	22,747	12,000	0	0	0	35,574
2043	1,074	23,882	12,000	0	0	0	36,957

The data center scenario was not iterated through the rate making model and the entire modeling system[5] (discussed in detail in Chapter 2), so a rate forecast was not produced for this scenario; however, a comparison of the net present value (NPV) of the 20-year total system cost from Aurora between the base forecast and the data center scenario reveals that the additional required resources necessary to meet the modeled data center load increases the NPV of the total system cost by 57 percent.

This total system cost from Aurora includes capital costs of new builds and ongoing operating, maintenance, and fuel costs for existing and new resources, net of any benefits such as revenue from market sales, energy savings, and tax credits. This total system cost from Aurora does not include costs associated with depreciation and return on equity of existing resources, the existing transmission and distribution system, or existing debt. These are all sunk costs and therefore are not included in the optimization model. Furthermore, costs associated with any transmission and distribution additions or upgrades required to serve the data center load are not included in this analysis. Thus, it is important to understand what is and what is not included in the total system cost

[5] The SUFG rate model allocates the cost of generating resources to all customer classes, so the cost of the additional resources needed to meet the data center load would affect the rates for all sectors. These rates would then flow through to the sector level energy models in the next iteration impacting the demand forecast in an undesirable fashion.

coming out of Aurora and that the 57 percent increase only represents an increase in a portion of the total costs rates would ultimately be based on.

It is also important to note that these increases in system costs do not necessarily translate into increases in electric rates. The addition of data centers increases resource needs and costs, but those costs are also spread over a much larger number of megawatt-hours. Electric rates can therefore increase, decrease, or remain relatively flat depending on the relative change in electricity output and revenue requirements.

The data center scenario should be viewed as a starting point and other data center scenarios could be modeled in the future with different assumptions about inputs such as load amounts, timing, ramp rates, and load factors.

Chapter 2

Overview of the SUFG Electricity Modeling System

Modeling System Changes

For this forecast, SUFG incorporated the Midcontinent Independent System Operator (MISO) Direct Loss of Load (DLOL) methodology into the seasonal reserve requirements and capacity accreditations for resources. A more detailed explanation can be found in the Resource Requirements section of this chapter.

A hybrid solar/battery storage new resource option was modeled for the first time.

Also, known non-data center large load adjustments were made to the commercial and industrial forecasts. These adjustments were provided by the utilities. Future large data centers are incorporated in a new data center scenario.

Finally, the tax credits that are available as a result of the Inflation Reduction Act of 2022, and first modeled in the previous forecast, have been adjusted to reflect changes resulting from the One Big Beautiful Bill Act (OBBBA) of July 2025. Since SUFG lacks the information necessary to determine whether utilities will receive bonus credits[1], or reduced credits[2], the standard credits are modeled.

Regulated Modeling System

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 models until equilibrium is attained. The SUFG modeling system is unique among utility forecasting and planning models because of its comprehensive and integrated characteristics.

A distinctive characteristic of the modeling system is its ability to capture the interaction between future electricity demand and electricity prices through an iterative process. During each cycle of the process, 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 utility finance & rates model to the "before" prices input to the energy consumption models. If these prices match, they are termed equilibrium prices in the sense that they balance demand and supply, and the iterative process ends. Otherwise, the modeling system continues to cycle through the models until equilibrium is attained as is illustrated in Figure 2-1.

[1] Bonus tax credits are available for meeting domestic content criteria, locating in an energy or environmental justice community and for locating in a low-income economic development project.
[2] The available tax credit rate is reduced for failing to meet prevailing wage and apprenticeship conditions.

Figure 2-1. Cost-Price-Demand Feedback Loop

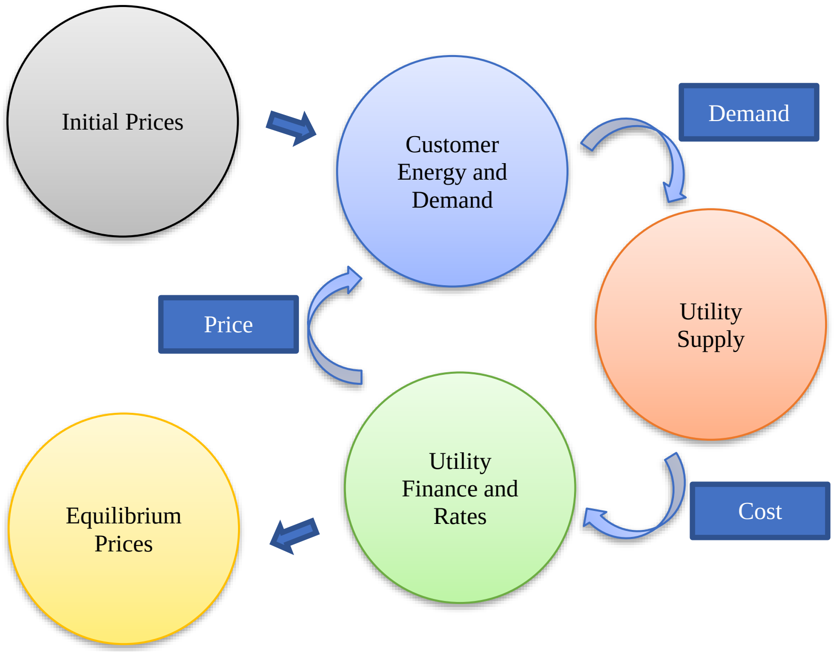
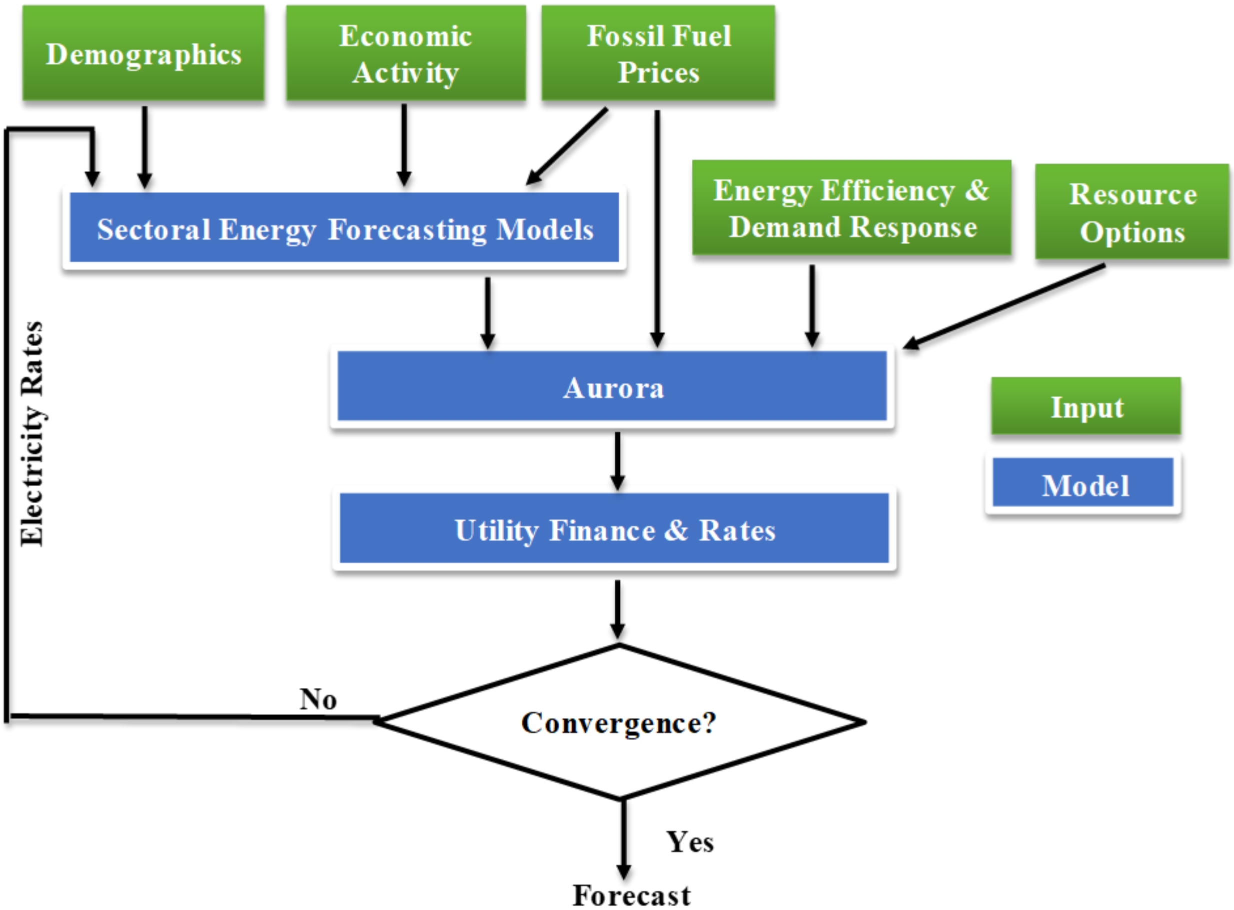


Figure 2-2 is a flowchart that illustrates how the modeling system functions. Projections of demographic, economic, and price drivers are inputs to utility and customer sector specific forecasting models. The energy and peak demand forecasts are inputs to Aurora, a commercially licensed optimization program that simulates economic dispatch, trade among the utilities, and determines future resources. Cost information from Aurora is passed to the utility finance models to determine the resulting prices. The energy forecasting models are then rerun with the new prices, starting the next iteration. The process is repeated until prices from one iteration to the next are stable, indicating that convergence has been achieved.

Figure 2-2. Forecasting Modeling System Flowchart



Energy Forecasting Models

The energy forecasting models are used to develop projections for each of the five investor-owned utilities (IOUs): AES Indiana, CenterPoint Energy, Duke Energy Indiana, Indiana Michigan Power Company, and Northern Indiana Public Service Company. In addition, projections are developed for the three not-for-profit (NFP) utilities: Hoosier Energy, Indiana Municipal Power Agency, and Wabash Valley Power Alliance.

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

SUFG currently projects energy use for each major customer group using end-use models for the investor-owned utilities and econometric models for the not-for-profits. 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. Additional information regarding SUFG's energy models for the residential, commercial, and industrial sectors can be found in Chapters 5, 6, and 7, respectively.

Electric Vehicle (EV) Projections

To produce the EV load forecast, the historical total car stock by utility in Indiana was derived first. The data on total car stock by county of Indiana from 2017-2024 were collected from the Indiana Bureau of Motor Vehicles (BMV) and the Indiana Vehicle Fuel Dashboard (IVFD) [Indiana Vehicle Fuel Dashboard, 2025] and then mapped to each utility based on the estimated fraction of load in each county that is served by each utility. Projections of total car stock by utility were developed using Indiana population projections from the Indiana University Center for Econometric Model Research (CEMR). It is assumed that the total car stock by utility grows at the same rate as the state population over time, with 2024 serving as the base year. SUFG assumed most EV penetration occurs in the residential sector, some in the commercial sector, but none in the industrial sector.

The EV penetration rate can be calculated by dividing the total EV stock by the total car stock. The total EV stock was derived by aggregating the vehicle numbers of three fuel categories from the IVFD - electric, electric-diesel hybrid and electric-gas hybrid. All EV data were available at the county level; they were mapped to the utility level using the same methodology used for the total car stock. Using EV stock and total car stock by utility, EV penetration rates were calculated by Indiana utility for each year from 2017 to 2024. At the national level, the history and projection of the total car stock and EV stock were retrieved from the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2025 Reference Case [EIA, 2025]. They were used to calculate the U.S. EV penetration history and projection into the future.

The AEO 2025 Reference Case projects the future U.S. energy system under the assumption that laws and regulations in effect as of December 2024 remain unchanged through 2050. Based on SUFG's analysis of EIA data, the national EV penetration rate is projected to reach 62% by 2050. On January 20, 2025, President Trump's "Unleashing American Energy" executive order rolled back EV policies by rescinding previous administration targets [Economic Policy Institute, 2025], halting EV infrastructure funding, revoking state emissions waivers, and potentially limiting federal EV tax credits. Subsequently, the One Big Beautiful Bill Act (OBBBA) [Congress.gov, 2025], signed into law on July 4, 2025, provides strong short-term federal EV purchase incentives—including new, used, and commercial vehicle credits—creating a temporary push for EV adoption; however, all vehicle purchase incentives expire after September 30, 2025, unless new legislation is enacted. To reflect these recent policy changes, SUFG made the decision to reduce the EV penetration rates projected in AEO 2025 across the forecast period. SUFG consulted studies on the effect of reversing previous federal policies on EV adoption by Harvard's Salata Institute [The Salata Institute, 2025] and Wood Mackenzie [Wood Mackenzie, 2025] and decided on a 20% adjustment which is roughly the average of the implied impact on penetration from those studies. After this adjustment, the U.S. EV penetration rate is expected to reach 50% by 2050, rather than 62%. It should be noted that although SUFG reduced the EIA national EV adoption projection by 20%, the final EV forecast is still significantly higher in the second half of the forecast period than the one used in SUFG's 2023 forecast due to the fact that EIA's AEO 2025 forecast is significantly higher than their AEO 2022 and 2023 ones to begin with.

A comparison of the historical state and national data shows that the EV penetration levels for all Indiana utilities are behind the U.S. level. For the year 2024, the U.S. EV penetration is 5.24%, while at the same time Indiana's EV penetration by utility ranges from 2.11% to 3.20%. Three forecast scenarios were developed based on Indiana's pace to catch up with the U.S. penetration level over time. The construction of the scenarios began by mapping the 2024 penetration rate for each Indiana utility to the national EV penetration history and finding the starting point for each utility on the national EV penetration trajectory. For example, in 2024, one Indiana utility's penetration rate was slightly higher than where the nation was in 2020 (or about 3.75 years behind the national level) while another Indiana utility was between where the nation was in 2018 and 2019 (or about 5.69 years behind the national level). For the Low Case, it is assumed that the EV penetration rate grows at the same rate as the adjusted national EV penetration from the starting point identified for each utility. The assumption means each Indiana utility will remain the same number of years behind the U.S. EV penetration level as identified at the starting point throughout the forecast period. For the Base Case, it is assumed that the Indiana utilities gradually catch up to the national level and reach the same level in 2050. For the High Case, it is assumed that the Indiana utilities catch up to the national level faster and get to the same level in 2040. The projections of the total number of EVs for the three scenarios were derived by multiplying the EV penetration projections by the total car stock projections for each utility.

As not all EVs require external battery charging, only battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) were considered as plug-in EVs. The historical and projected shares of BEVs and PHEVs out of total EVs were estimated based on data from EIA's AEO 2025 and applied to the total EV projections to derive the plug-in EV forecast by utility under the three scenarios.

To develop projections of weekly load profiles, the Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite from the U.S. Department of Energy's Office of Energy Efficiency & Renewable Energy was used [U.S. Department of Energy's Office of Energy Efficiency & Renewable Energy, 2025]. This tool provides a simple way to estimate how much electric vehicle charging you might need and how it affects your charging load profile. The basic assumptions used to generate the load profiles follow.

1. The average daily miles traveled per vehicle is assumed to be 35 miles.
2. The average ambient temperature is assumed to be 50°F for March to May and September to November, 68°F for June to August, and 32°F for December to February.[3] By using different ambient temperatures, generic load profiles by month were obtained.
3. 75% of EVs are all electric EVs, 25% of EVs are PHEVs.[4]
4. 50% of plug-in vehicles are sedans.
5. The mix of workplace charging includes 50% level 1 and 50% level 2.[5]
6. 75% have access to home charging and 25% do not. In addition, the distribution of charging power for drivers with access to home charging includes 50% Level 1 and 50% Level 2.
7. 80% of drivers in the fleet prefer primarily charging at home.
8. The home charging strategy assumes vehicles begin charging as soon as possible upon arriving at a charging location and charge at full power/speed until fully charged or the vehicle departs.
9. The workplace charging strategy also assumes vehicles begin charging as soon as possible upon arriving at a charging location and charge at full power/speed until fully charged or the vehicle departs.

[3] A limited number of options were available for average ambient temperature.
[4] Based on 2023 data from AEO 2025, BEVs accounted for 75% of all plug-in electric vehicles.
[5] Level 1 EV charging uses a standard 120-volt household outlet for slow charging, adding a few miles of range per hour and suitable for overnight charging or plug-in hybrids. Level 2 charging uses a higher-powered 240-volt supply, delivering significantly faster charging speeds of about 32 miles of range per hour, making it ideal for most EV owners to fully charge their vehicles in 4-8 hours.

SUFG obtained generic weekly load profiles at hourly granularity by month resulted from a fleet of 30,000 plug-in EVs from the EVI-Pro Lite. The weekly load profiles by month were then scaled by the plug-in EV adoption level forecast previously derived for each utility and each forecast year. Finally, the weekly load profile for each Indiana utility and each month of a forecast year was obtained for each one of the three scenarios.

Aurora

Energy Exemplar's Aurora is an optimization program that can perform economic dispatch of generators, allowing for trade among utilities, and determine least-cost resource expansion. Within the SUFG integrated modeling system, it is used to determine the operating costs associated with meeting future loads and the costs of expanding the future set of resources necessary to meet future reserve requirements.

Aurora can consider a variety of future supply-side and demand-side resource options. For this forecast, SUFG included utility-scale solar and wind, battery storage (BESS), hybrid solar/battery storage, natural gas-fired combustion turbines and combined cycle units, and small modular reactors (SMR). Costs and operating characteristics were taken from Energy Information Administration (EIA) [EIA, 2024] and National Renewable Energy Laboratory (NREL)[6] [NREL, 2024] sources. Specifically, an average of EIA and NREL (moderate case) costs were used for starting values and then NREL's trajectories were applied. Due to data limitations, demand-side resources were not modeled as a resource option. Utility energy efficiency programs and DR were modeled as fixed quantities based on utility-provided information. See Chapter 4 for more information on the modeling of demand-side resources.

Aurora has the functionality to allow for construction of partial resources. Thus, the model may select to add a fraction of a unit rather than being limited to full units. SUFG has elected to use this option since it facilitates finding an equilibrium solution.

Utility Finance and Rates Models

As part of the upgrades to the modeling system starting with the 2017 forecast, SUFG incorporated new financial models to project future electric rates. The current financial model is a modified version of the ORFIN model that was developed by Oak Ridge National Lab. The models determine annual revenue requirements based on each utility's costs associated with existing and future capital investments, operational expenses, debt, and taxes. Those costs are then allocated to the customer sectors and rates are determined using the annual energy forecasts.

Resource Requirements

To determine future resource requirements, SUFG has historically used individual utility reserve margins that reflect the planning reserve requirements of the utility's regional transmission organization (RTO) to determine the seasonal reserve requirements. The combination of changing to a seasonal construct in the previous forecast and now incorporating MISO's Direct Loss of Load (DLOL) methodology in the current forecast led SUFG to make the decision to model all the utilities this time as if they are members of MISO[7].

DLOL is not implemented until the 2028-2029 MISO planning year, therefore, there are now two sets of reserve margin targets modeled; before and after DLOL. Applying the individual reserve

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[6] NREL was renamed the National Laboratory of the Rockies (NLR) in December 2025.
[7] SUFG analysis showed that treating all utilities as MISO members made no significant difference in the summer season and very little difference in other seasons.

requirements and adjusting for peak load diversity among the utilities provides a statewide reserve requirement prior to DLOL of 17.9 percent for summer, 27.1 percent for fall, 41.6 percent for winter, and 41.6 percent for spring. Once DLOL is implemented, the targets are 11.8 percent for summer, 20.9 percent for fall, 36.1 percent for winter, and 33.7 percent for spring. This requirement is based on the installed capacity value of the resources, with a modification for the capacity credit for intermittent resources.

The existing capacity has been adjusted for retirements, utility purchases and sales, and new construction projects that have been approved by the Indiana Utility Regulatory Commission (IURC) at the time the inputs to the modeling system were finalized[8].

The numbers presented in this report for future resource requirements are the installed capacity selected by Aurora and are not modified for intermittent resources. While SUFG identifies resource needs in its forecasts, it does not advocate any specific means of meeting them. Required resources could be met through conservation measures, purchases from merchant generators or other utilities, construction of new facilities, or some combination thereof. The best method for meeting resource requirements may vary from one utility to another.

Scenarios

SUFG's electricity projections are based on assumptions such as economic growth, construction costs, and fossil fuel prices. These assumptions are a principal source of uncertainty in any energy forecast. Another major source of uncertainty is the statistical error inherent in the structure of any forecasting model. To provide an indication of the importance of these sources of uncertainty, scenario-based projections are developed by operating the modeling system under varying sets of assumptions. These low probability, low and high growth scenarios, capture the uncertainty associated with economic growth and statistical error in the model structure. EV projections for the low and high scenarios were developed by adjusting the rate at which utility EV penetration increases relative to the EIA forecast. Additionally, new to this forecast, SUFG also modeled a scenario incorporating estimates of future data center loads.

Presentation and Interpretation of Forecast Results

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

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[8] The inputs were finalized in the summer of 2025.

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Chapter 3

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

Introduction

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

Most Probable Forecast

As shown in Tables 3-1 and 3-2 and Figures 3-1 and 3-2, SUFG's current base scenario projection indicates annual growth of 1.03 percent for electricity requirements and 0.61 percent for peak demand. As shown in Table 3-3, the overall growth rate for electricity sales in this forecast is about 0.52 percent higher than the 2023 forecast. The 2025 forecast grows more rapidly than the previous one, however, the level of the forecast is lower than the previous one until the last several years and this pattern can be seen in the residential, commercial, and industrial sectors. The lower sales forecasts are driven by a number of factors that are offsetting generally higher economic projections and lower utility-sponsored energy efficiency during that time. The residential and industrial sectors start from a noticeably lower level in the previous forecast. Projected electricity prices are higher than in the previous forecast and rise until 2034 before they level off and slightly decline. These higher electricity prices are putting downward pressure on demand. The electric vehicle forecast in the first part of the forecast is lower than in the previous one due to an improvement in identifying and removing non-plug-in vehicles from the stock of total electric vehicles. The late growth that begins around 2034 is driven by flattening and slightly declining electricity prices as well as significantly higher electric vehicle projections than in the previous forecast. See Chapters 5, 6, and 7 for discussions of the forecast growth in the residential, commercial, and industrial sectors.

The growth in peak demand is also higher than that projected in the previous forecast. Forecast peak demand growth is a little lower than that of electricity requirements (0.61 versus 1.03 percent). Another measure of peak demand growth can be obtained by considering the average year to year peak MW load change. In Figure 3-2, the annual increase is about 128 MW compared to about 85 MW per year in the previous forecast.

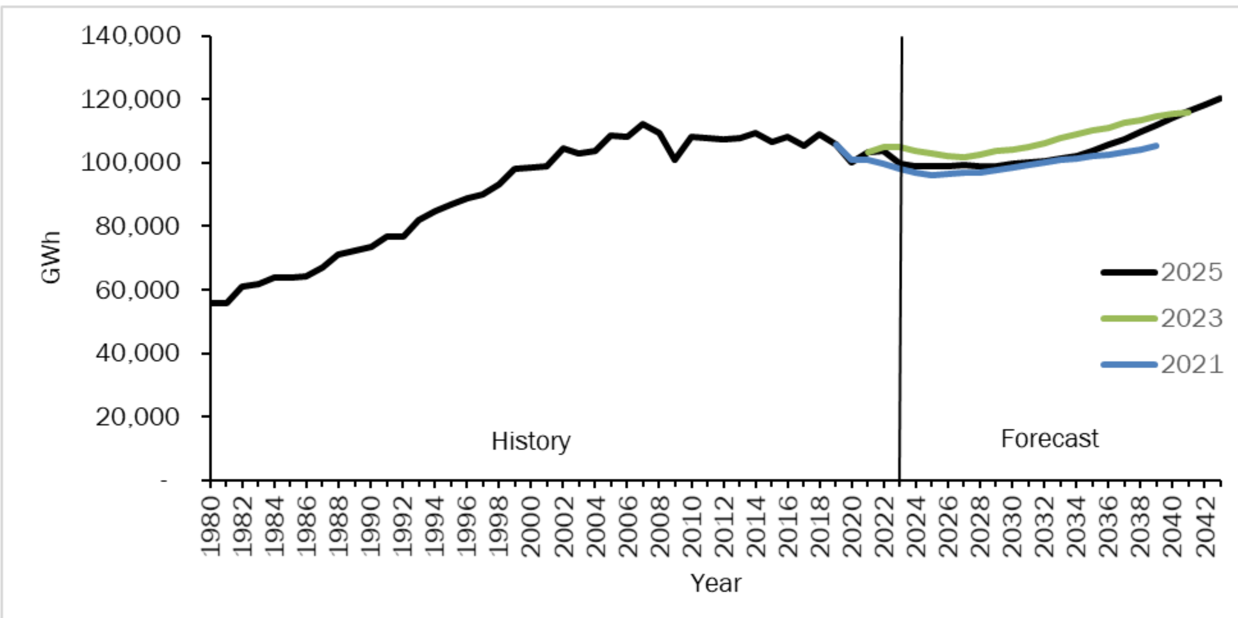
Demand-Side Resources

Beginning with the 2017 forecast, SUFG adjusted the manner in which demand response (DR) programs are modeled and how they are reported. This was necessitated due to the manner in which DR is modeled within Aurora. DR programs are now treated as a resource within the modeling system; previously an adjustment of peak demand was done to account for them outside the utility simulation model. Thus, the peak demand numbers reported in this report have not been adjusted for DR, while the existing resource numbers now include them. DR programs are projected to decline from about 1,000 MW in 2024 to about 680 MW in 2025 before increasing again to about 960 MW by 2040. As in the past, energy efficiency (EE) programs are treated as a reduction in demand. The current projection includes the energy and demand impacts of existing or planned utility-sponsored EE programs. Incremental EE programs, which include new programs and the expansion of existing programs, are projected to reduce peak demand by approximately 120 MW at the beginning of the forecast period and by about 1,200 MW at the end of the forecast. See Chapter 4 for additional information about DR and EE.

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

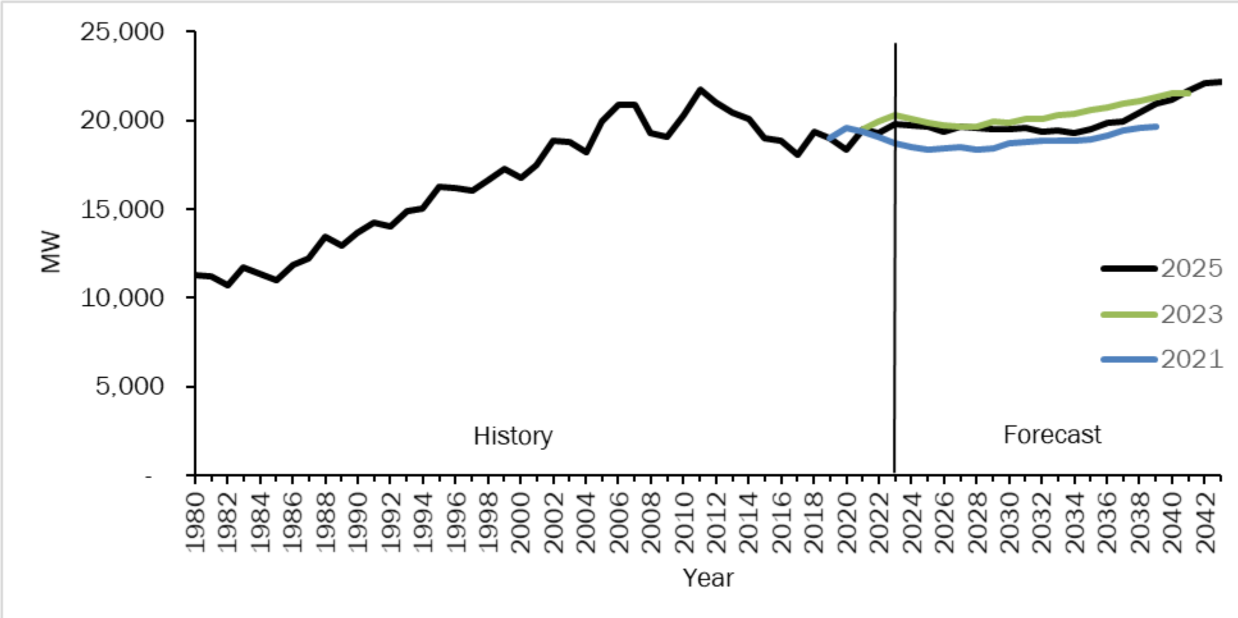
Forecast	CAGR	Time Period
2025	1.03	2024-2043
2023	0.51	2022-2041
2021	0.21	2020-2039

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



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

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



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

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

Forecast	CAGR	Time Period
2025	0.61	2024-2043
2023	0.40	2022-2041
2021	0.02	2020-2039

Table 3-3. Annual Electricity Sales Growth (Percent) by Sector (Current Forecast vs. 2023 and 2021 Projections)

Sector	Current (2024-2043)	2023 (2022-2041)	2021 (2020-2039)
Residential	1.81	1.28	0.61
Commercial	0.05	-0.19	-1.02
Industrial	0.85	0.20	0.53
Total	1.03	0.51	0.20

Supply-Side Resources

SUFG's base resource plan includes all planned capacity changes at the time the model inputs were finalized[1]. Planned capacity changes include: certified, rate base eligible generation additions, retirements, changes in the amount of demand response that is available, and net changes in firm out-of-state purchases and sales.

SUFG does not attempt to forecast long-term out-of-state contracts other than those currently in place. Generic new generating units are added as necessary during the forecast period to meet seasonal reserve requirements. SUFG has historically used individual utility reserve margins that reflect the planning reserve requirements of the utility's regional transmission organization (RTO) to determine the seasonal reserve requirements, however, as explained in Chapter 2, the utilities are now all modeled as if they are members of MISO. Additionally, the incorporation of MISO's Direct Loss of Load (DLOL) methodology has resulted in the reserve margin targets changing from the pre-DLOL period (2024-2027) to the DLOL period (2028-2043). Applying the individual reserve requirements and adjusting for peak load diversity among the utilities, the statewide reserve requirement prior to DLOL is 17.9 percent for summer, 27.1 percent for fall, 41.6 percent for winter, and 41.6 percent for spring. Once DLOL is implemented, the targets are 11.8 percent for summer, 20.9 percent for fall, 36.1 percent for winter, and 33.7 percent for spring. See Chapter 2 for more information on the seasonal reserve requirements.

Aurora can consider a variety of future supply-side and demand-side resource options. For this forecast, SUFG included utility-scale solar and wind, battery storage (BESS), hybrid solar/battery, natural gas-fired combustion turbines and combined cycle units, and small modular reactors (SMR). Costs and operating characteristics were taken from Energy Information Administration (EIA) [EIA, 2024] and National Renewable Energy Laboratory (NREL)[2] [NREL, 2024] sources. Specifically, an average of EIA and NREL (moderate case) costs were used for starting values and then NREL's trajectories were applied. Due to data limitations, demand-side resources were not modeled as a selectable resource option. Utility energy efficiency and demand response loads were modeled as fixed quantities based on utility-provided information.

Table 3-4 and Figure 3-3 show the statewide resource plan for the SUFG base scenario for the summer season. This forecast indicates that additional resources are needed throughout the forecast period except for 2027-2028. Additional resource needs in the first half of the forecast are driven by the need for replacement capacity for units that will be retiring in that time. Additional resource needs in the second half of the forecast are driven by both retirements of existing units and increasing demand. The Aurora optimization program may add more new resources than what is strictly necessary to meet the seasonal reserve requirements in some years if it finds it economic to do so. This forecast indicates a need for a mix of natural gas-fired combustion turbines and combined cycle units, wind, and solar capacity. Wind and solar resources are added first, while natural gas is not added until 2029. Wind is added throughout the forecast and additional solar is selected late in the period. While no battery storage or hybrid solar/battery resources were selected in the final forecast run, some were selected in earlier iterations. Nuclear small modular reactors

[1] The inputs to the model were finalized in the summer of 2025. As of the time that this report was published, 2,346 MW of additional natural gas resources have been approved by the IURC. Additionally, 744 MW of additional wind PPAs have been approved by the IURC with another 268 MW currently pending approval. The impact of the approved natural gas and wind resources would be to reduce or defer some of the resource additions selected by Aurora. The resources still pending approval would have the same effect, if approved.
[2] NREL was renamed the National Laboratory of the Rockies (NLR) in December 2025.

were never selected. In the long term, the projected required additional resources are lower than in the previous forecast, due to more IURC-approved resources being added during the forecast period and fewer scheduled retirements of existing units, as well as lower sales and peak demand projections for most of the forecast period.

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

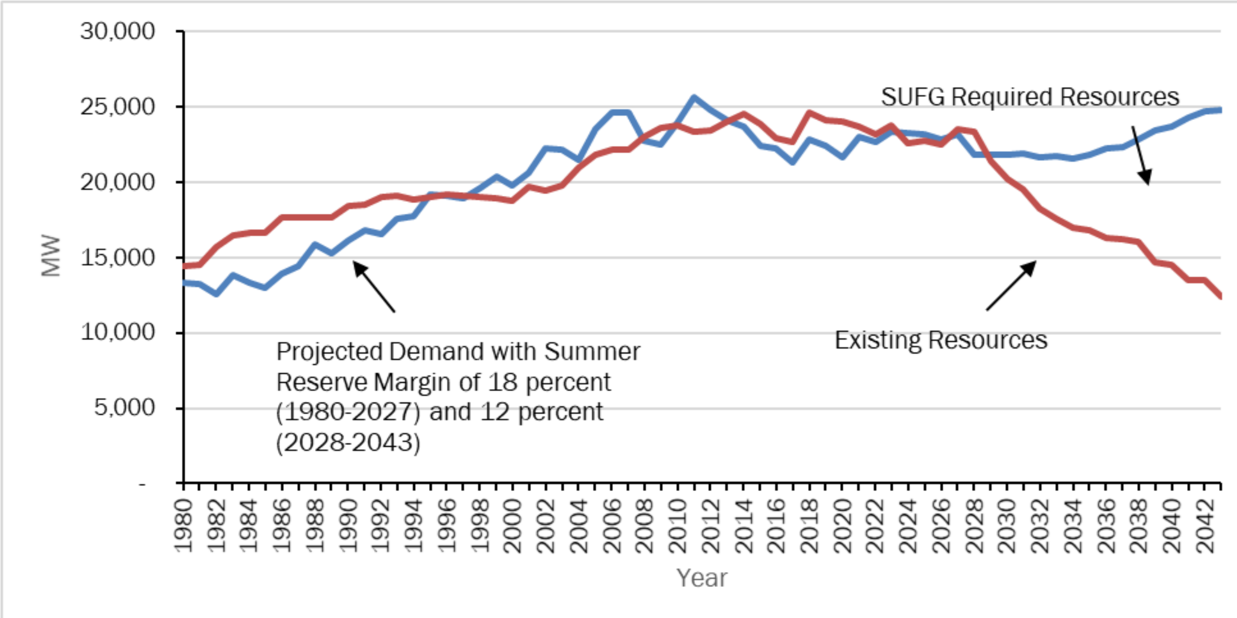
Due to data availability restrictions at the time that SUFG prepared the modeling system to produce this forecast, the most current year with a complete set of historical data was 2023. Therefore, 2024 and 2025 numbers do not include short-term purchases and any longer-term purchases of which SUFG was not aware at the time the forecast was prepared.

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

Year	Peak Demand[1]	Existing/ Approved Resources[2]	Incremental Change in Resources[3]	Required Additional Resources[4]	Additional Selected Resources[5]						
					CT	CC	Wind	Solar[6]	BESS[6]	SMR	Total
2024	19,720	22,586		668	0	0	1,691	780	0	0	2,471
2025	19,666	22,729	144	461	0	0	1,691	780	0	0	2,471
2026	19,379	22,464	-266	388	0	0	1,918	780	0	0	2,699
2027	19,639	23,527	1,064	0	0	0	1,918	780	0	0	2,699
2028	19,546	23,379	-148	0	0	0	1,918	780	0	0	2,699
2029	19,493	21,373	-2,007	425	0	775	1,918	780	0	0	3,474
2030	19,502	20,214	-1,158	1,593	0	1,093	3,923	780	0	0	5,797
2031	19,597	19,557	-657	2,356	0	1,669	4,908	780	0	0	7,358
2032	19,353	18,247	-1,310	3,393	0	3,571	5,907	780	0	0	10,259
2033	19,419	17,554	-693	4,160	0	3,571	6,684	780	0	0	11,036
2034	19,285	16,953	-601	4,612	0	3,875	7,173	780	0	0	11,828
2035	19,485	16,823	-130	4,965	0	4,209	7,603	780	0	0	12,593
2036	19,884	16,329	-494	5,905	0	4,995	8,644	780	0	0	14,420
2037	19,957	16,185	-143	6,131	0	5,185	9,255	780	0	0	15,220
2038	20,414	16,081	-104	6,746	0	6,283	9,466	780	0	0	16,530
2039	20,956	14,658	-1,423	8,775	0	7,750	10,535	780	0	0	19,065
2040	21,150	14,530	-128	9,119	0	7,981	12,000	780	0	0	20,761
2041	21,683	13,533	-997	10,713	180	9,270	12,000	2,566	0	0	24,017
2042	22,068	13,464	-69	11,213	180	9,836	12,000	2,566	0	0	24,582
2043	22,155	12,350	-1,114	12,424	288	11,004	12,000	2,566	0	0	25,859

1 Peak demand reflects utility-sponsored energy efficiency programs but is not adjusted for demand response loads.
2 Existing/approved resources include installed capacity plus approved new capacity plus demand response plus firm purchases minus firm sales.
3 Incremental change in resources is the change in existing/approved resources from the previous year. The change is due to new, approved capacity becoming operational, retirements of existing capacity, changes in available demand response loads, and changes in firm purchases and sales.
4 Required additional resources represent the amount of additional resources that are needed to meet the target statewide reserve margin.
5 Additional selected resources are the cumulative amount of additional resources chosen by the optimization model to meet future demand at least cost.
6 The Solar and BESS columns include any amounts from hybrids that were selected.

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



Equilibrium Price and Energy Impact

The SUFG modeling system is designed to forecast an equilibrium price that balances electricity supply and demand. This is accomplished through the cost-price-demand feedback loop, as described in Chapter 2. The impact of this feature on the forecast of electricity requirements can be significant if price changes are large.

SUFG's base scenario equilibrium real electricity price trajectory is shown in Table 3-5 and Figure 3-4. Real prices are projected to increase by 52 percent from 2024 to 2034 and then level off and slightly decline until the end of the forecast period. While prices are affected by a number of different factors, the change in prices early in the forecast horizon results primarily from the significant capital investment in transmission, distribution, and newly approved generation that is modeled in the first half of the forecast. The earlier expiration of tax credits due to the One Big Beautiful Bill Act (OBBBA) is a contributing factor as well.

The price increase is significant and higher than in the previous forecast while closer to the 2021 forecast. Thus, the electricity requirements projection for this portion of the forecast period is affected. Since electricity prices are an input to the forecasting models, the price increases in the early years cause the projected sales to decrease. In turn, this can cause further price increases if sales decline more than revenue requirements.

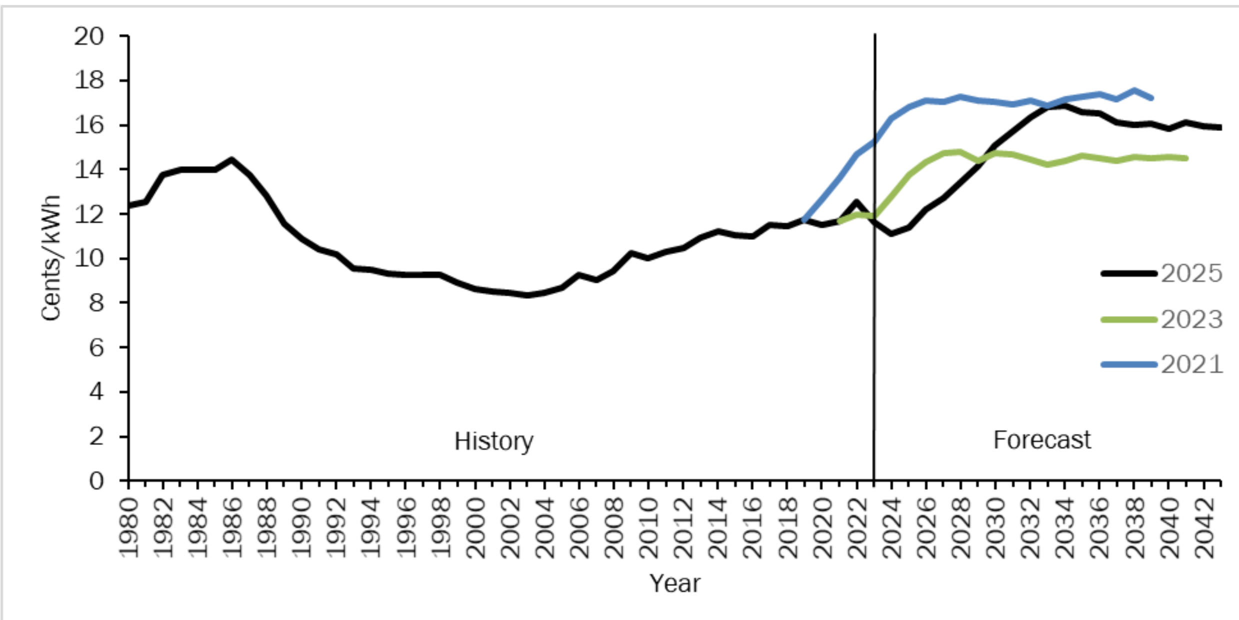
SUFG's equilibrium price projections for two previous forecasts are also shown in Table 3-5 and Figure 3-4. The price projection labeled "2021" is the base case projection from SUFG's 2021 forecast report and the one labeled "2023" is the base case projection from SUFG's 2023 report. For the prior price forecasts, SUFG rescaled the original price projections to 2023 dollars (from 2019 dollars for the 2021 projection, and from 2021 dollars for the 2023 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

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

Forecast	CAGR	Time Period
2025	1.90	2024-2043
2023	1.04	2022-2041
2021	1.64	2020-2039

A number of factors determine the price projections in Figure 3-4. These include costs associated with future resources required to meet future load, costs associated with continued operation of existing infrastructure, and fuel costs. Costs are included for the transmission and distribution of electricity in addition to production. SUFG's 2025 forecasts assume that the greenhouse gas emissions restriction for fossil-fueled electric generating units under Section 111 of the Clean Air Act goes away[3]. Environmental rules, aside from the aforementioned one, that are in place at the time the forecast was prepared are included, while proposed and potential future rules are not.

Figure 3-4. Indiana Real Price Projections in cents/kWh (2023 Dollars) (Historical, Current, and Previous Forecasts)



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

Low and High Scenarios

SUFG has used alternative macroeconomic scenarios, reflecting low and high growth in real personal income, population, non-manufacturing employment, and gross state product. These low probability scenarios are used to indicate the forecast range, or dispersion, of possible future trajectories but do not represent limits. The addition of very large new users of electricity could result in sales that exceed the high scenario. Similarly, the closure of existing large users could result in sales below the low scenario. Tables 3-6 and 3-7 and Figures 3-5 and 3-6 provide the statewide electricity

[3] SUFG tested an alternative version of the base forecast in which capacity factor limits were applied to new gas builds (40% for CC; 20% for CT) in order to capture Clean Air Act section 111 (b). The results were that fewer megawatts of natural gas resources were selected while more renewable resources were selected, as expected.

requirements and peak demand projections for the base, low, and high scenarios. As shown in those figures, the annual growth rates for energy requirements for the low and high scenarios are 0.30 percent lower and 0.19 percent higher, respectively, than the base scenario. These differences are driven by economic growth assumptions in the scenario-based projections and differences in assumed growth of electric vehicles.

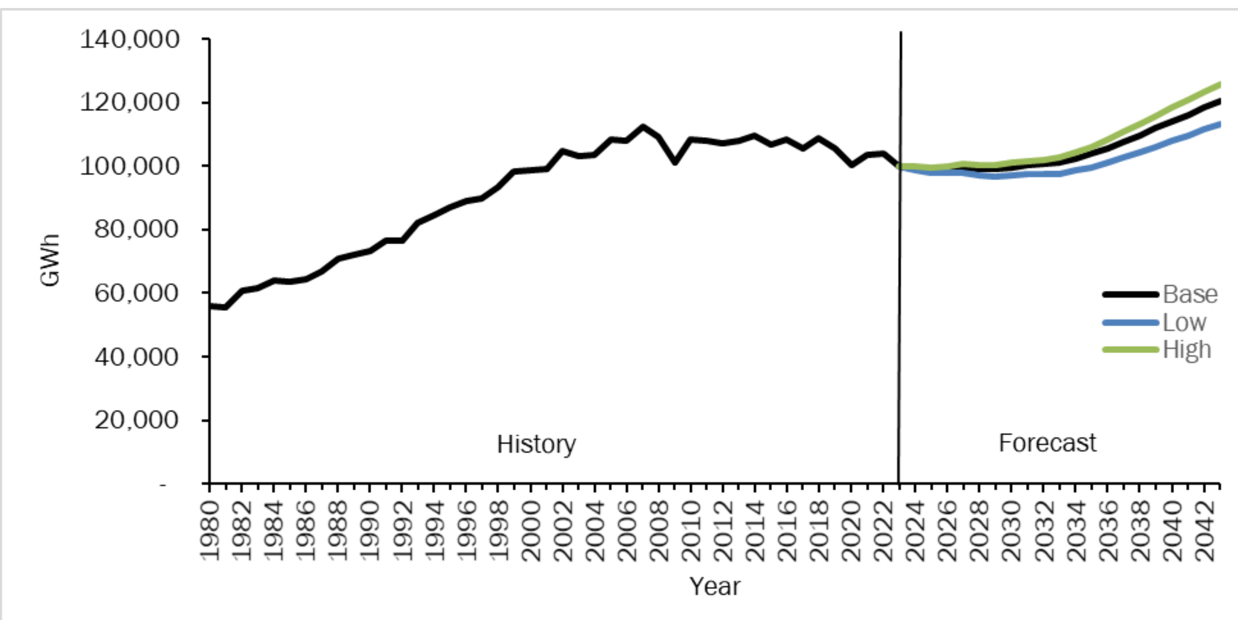
Resource and Price Implications of Low and High Scenarios

Resource plans are developed for the low and high scenarios using the same methodology as the base plan. Demand-side resources, including energy efficiency and demand response loads, are the same in all three scenarios, as are retirements of generating units. Table 3-8 shows the resources selected by the optimization model for the high and low scenarios (the same information for the base scenario can be found in Table 3-4). Approximately 28,300 MW over the horizon are added in the high scenario compared to 28,200 MW in the low scenario. The small difference in the totals is misleading and due to the fact, that in the low case a very large amount of solar is selected in the last year of the forecast when the capacity accreditation for solar is very low, thus making it appear the low resource build is only slightly smaller than in the high case when, in fact, it is significantly lower when looked at overall. By the end of the forecast period, electricity prices in both the high case and the low case are within about six percent of those projected in the base case. This is because the higher costs associated with meeting the increased load for the high case are spread over a greater amount of energy. For the low case, the lower costs are offset by the lower amount of energy.

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

Forecast Period	Base	Low	High
2024-2043	1.03	0.73	1.22

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

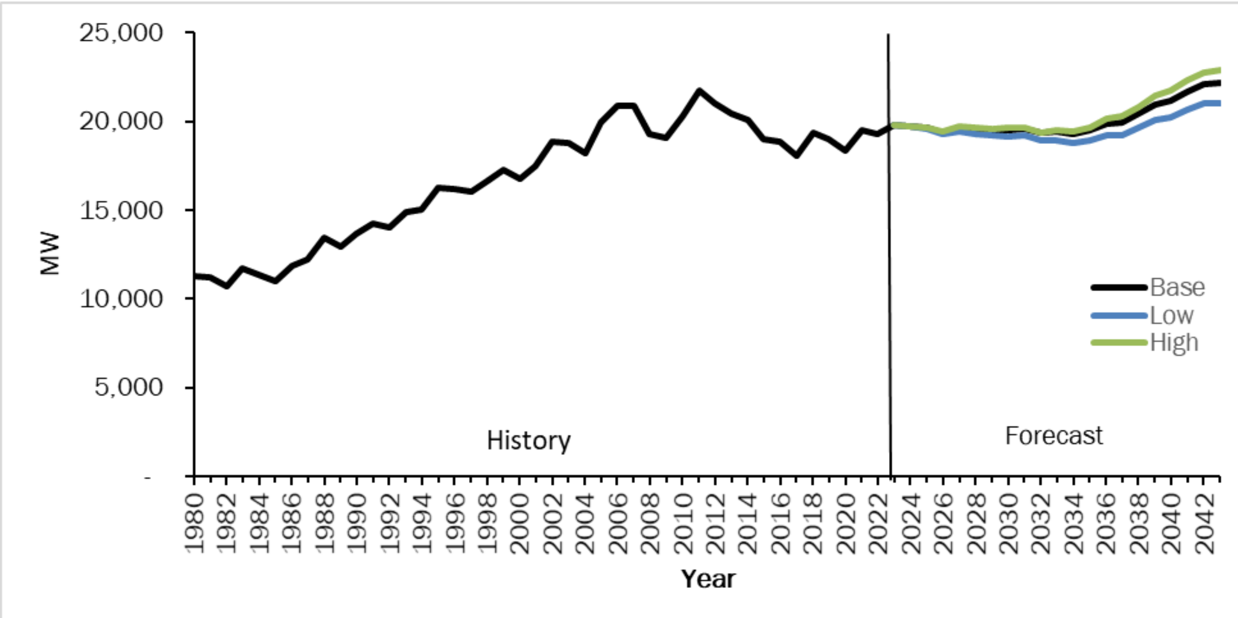


Note: See the Appendix to this report for historical and projected values.

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

Forecast Period	Base	Low	High
2024-2043	0.61	0.34	0.78

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



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

Table 3-8. Indiana Selected Resources for High and Low Scenarios in MW

Year	High							Low						
	CT	CC	Wind	Solar	BESS	SMR	Total	CT	CC	Wind	Solar	BESS	SMR	Total
2024	0	672	0	0	0	0	672	0	0	2,171	589	0	0	2,760
2025	0	672	0	0	0	0	672	0	0	2,171	589	0	0	2,760
2026	0	672	0	158	0	0	830	0	0	2,214	589	0	0	2,803
2027	0	672	0	158	0	0	830	0	0	2,214	589	0	0	2,803
2028	0	672	555	158	0	0	1,385	0	0	3,042	589	0	0	3,631
2029	0	1,145	7,517	158	0	0	8,820	0	702	3,042	589	0	0	4,333
2030	0	1,299	7,517	158	0	0	8,974	0	1,366	3,042	589	0	0	4,997
2031	0	1,857	9,176	158	0	0	11,191	0	1,781	3,451	589	0	0	5,820
2032	0	3,710	12,000	158	0	0	15,868	0	3,313	4,322	589	0	0	8,224
2033	0	3,738	12,000	158	0	0	15,896	0	3,438	4,322	589	0	0	8,349
2034	0	4,029	12,000	158	0	0	16,187	0	3,845	4,466	589	0	0	8,900
2035	0	4,465	12,000	158	0	0	16,623	0	3,994	4,838	589	0	0	9,421
2036	0	5,524	12,000	158	0	0	17,682	0	4,522	6,062	589	0	0	11,173
2037	0	5,847	12,000	158	0	0	18,005	0	4,724	6,062	589	0	0	11,375
2038	0	6,552	12,000	158	0	0	18,710	0	5,658	6,062	589	0	0	12,309
2039	0	8,594	12,000	650	0	0	21,244	0	6,854	10,067	589	0	0	17,510
2040	0	9,049	12,000	650	0	0	21,699	0	7,132	10,251	589	0	0	17,972
2041	0	10,704	12,000	650	0	0	23,354	0	8,582	10,251	1,708	0	0	20,541
2042	5	11,258	12,000	1,994	0	0	25,256	0	9,103	10,251	1,708	0	0	21,062
2043	1,074	11,488	12,000	3,766	0	0	28,328	19	10,164	10,251	7,772	0	0	28,207

Data Center Scenario

Data centers in the US have become a formidable and rapidly growing electricity consumer. In 2016, data centers consumed about 60 TWh. With the creation of artificial intelligence (AI) servers, this number began to rise, reaching 76 TWh by 2018, or roughly 1.8% of US electricity consumption. By 2023, data centers accounted for 4.4% of national electricity, roughly 176 TWh. Projections from Berkley National Lab suggest data centers could consume anywhere from 325 to 580 TWh per year by 2028, or 6.7% to 12% of US electric consumption [LBNL, 2025].

Indiana, particularly Northwest Indiana, has become a prominent area in the emerging market of data centers. A combination of affordable land, robust infrastructure, reliable power access, and fiscal incentives has positioned the region as an attractive destination for new development. The state offers large industrial parcels with proximity to rail lines and interstate highways, access to high-speed fiber optic networks, and abundant cooling water from Lake Michigan [CBRE, 2024]. Critically, Indiana is uniquely situated within the footprints of both the MISO and PJM power grids, enhancing reliability and resilience for energy-intensive facilities. These strengths match well with core data center location criteria: tax incentives, access to infrastructure, land that is ready for development, availability of water and electricity, and a skilled workforce for both construction and operation of the facilities [Indiana Office of Fiscal and Management Analysis, 2025].

Indiana also provides fiscal incentives to companies building data centers in the state. In 2019, IC § 6-2.5-15 was added to the Indiana tax code, which is a sales and use tax exemption on equipment used for data centers. The code gives a up to 25-year sales and use tax exemption for projects under $750 million, and a up to 50-year exemption for projects over $750 million [Indiana General

Assembly, 2025]. Equipment that is eligible for the exemption includes: servers and related computer equipment; software purchased or leased for the processing, storage, retrieval and communication of data; and other equipment essential to the operation of a data center. A 2024 report from the Office of Fiscal and Management Analysis for Indiana estimates that current and announced data centers in Indiana will bring in between $13.98 billion and $20.83 billion and create 1,375 jobs. Of that, as much as $8.8 billion to $13.2 billion in equipment purchases could potentially be exempt from sales tax [Indiana Office of Fiscal and Management Analysis, 2025].

In light of the significant interest in the state currently surrounding data centers and their potential to dramatically impact required resources, SUFG prepared a data center scenario as part of the 2025 forecast. This data center scenario focuses on estimates of future data center additions, particularly the large hyperscalers, but it should be noted that Indiana already has smaller data centers that are effectively included in the base forecast (and low and high).

Indiana, unlike some other states such as Virginia [Dominion Energy, 2025], lacks substantial historical load data on large data centers, which makes creating econometric or end-use models impractical. SUFG's existing models will not capture these data center additions, therefore, the data center loads must be layered onto the existing commercial or industrial forecasts, depending on how each utility classifies them[4].

SUFG is not independently forecasting data center load, but rather layering on amounts provided by the utilities through confidential data requests and in some cases the utilities' Integrated Resource Plan (IRP) presentations. SUFG does not have the ability to independently verify the data from the utilities and, in effect, will have to trust the information being provided by the utilities. The data center landscape in Indiana is also changing rapidly as new ones are proposed while some are withdrawn due to local community efforts to stop them[5].

SUFG first asked for this information from the utilities as part of the usual Spring 2024 data request and the responses arrived in the late August/September 2024 time frame. SUFG then asked the utilities for updates in May 2025 and the responses arrived around June 2025.

SUFG incorporated data center load amounts for two utilities, AES Indiana[6] and CenterPoint Energy[7], based on information provided in their 2025 IRP stakeholder meetings. The data from these IRP meetings is less certain than some of the data other utilities provided in their data request responses and even some of that data is not certain. There is considerable uncertainty around the data center amounts SUFG modeled in this scenario.

The data provided by utilities are megawatt (MW) values which SUFG converted to megawatt-hours (MWh) using load factors, added transmission and distribution losses, and then recalculated megawatts including losses. The load factors were mostly provided by the utilities and are in the 90-95% range and when unavailable SUFG assumed 90%. The total aggregated amount of new data center load included in the data center scenario dramatically increases the Indiana energy required and peak demand as can be seen in Figure 3-7 and Figure 3-8.

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[4] NIPSCO classifies data centers as industrial while the other Indiana utilities classify them as commercial.
[5] SUFG is aware of at least six proposed data centers that have been withdrawn.
[6] SUFG used the Mid case from page 11 of their September 10, 2025 Public Advisory Meeting #3 presentation.
[7] SUFG estimated values from the Alternate Reference Case Summer Peak chart on page 22 of their September 11, 2025 Public Stakeholder Meeting 3 presentation.

Figure 3-7. Indiana Energy Required (GWh) Base Scenario vs. Data Center Scenario

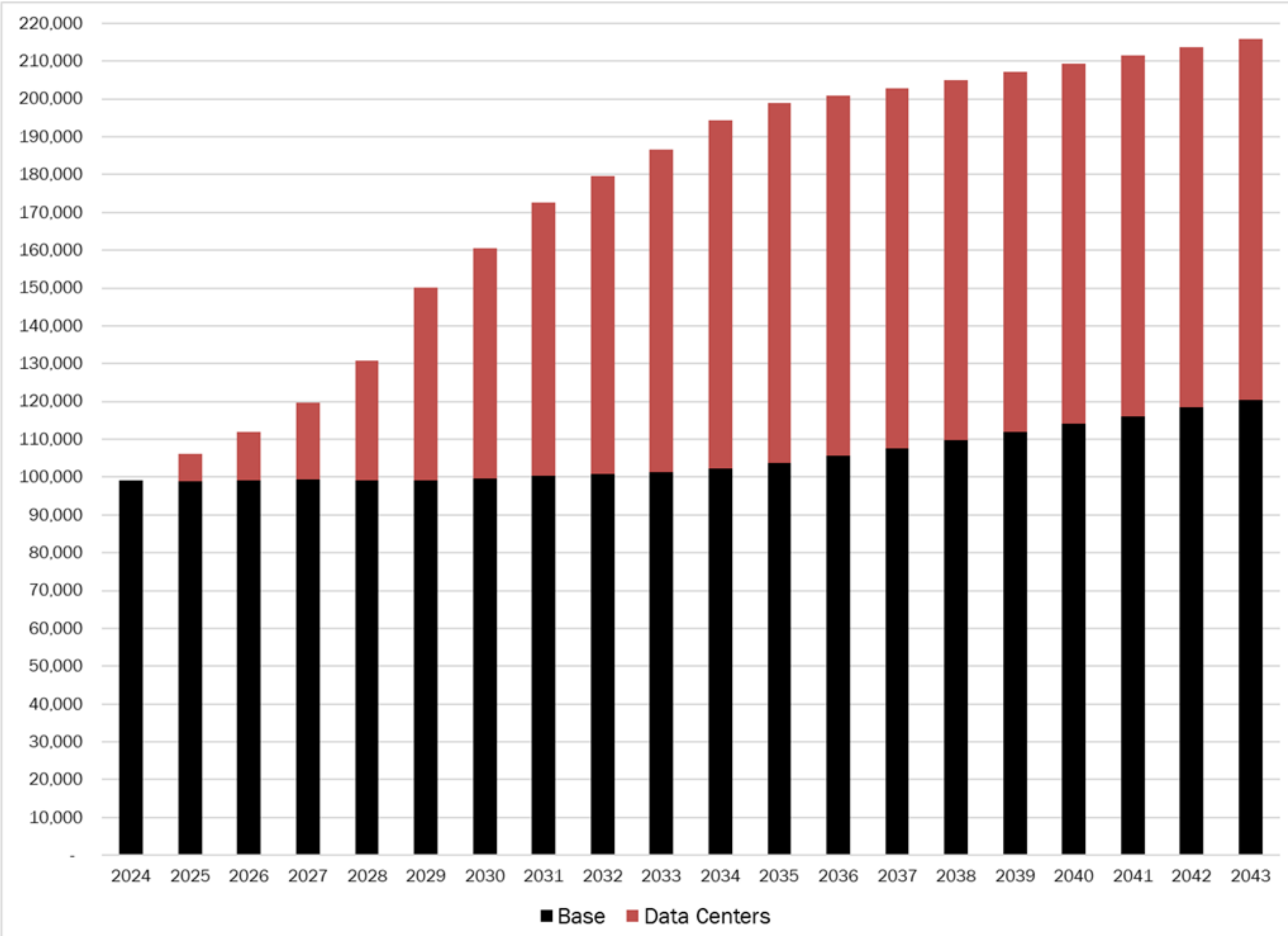
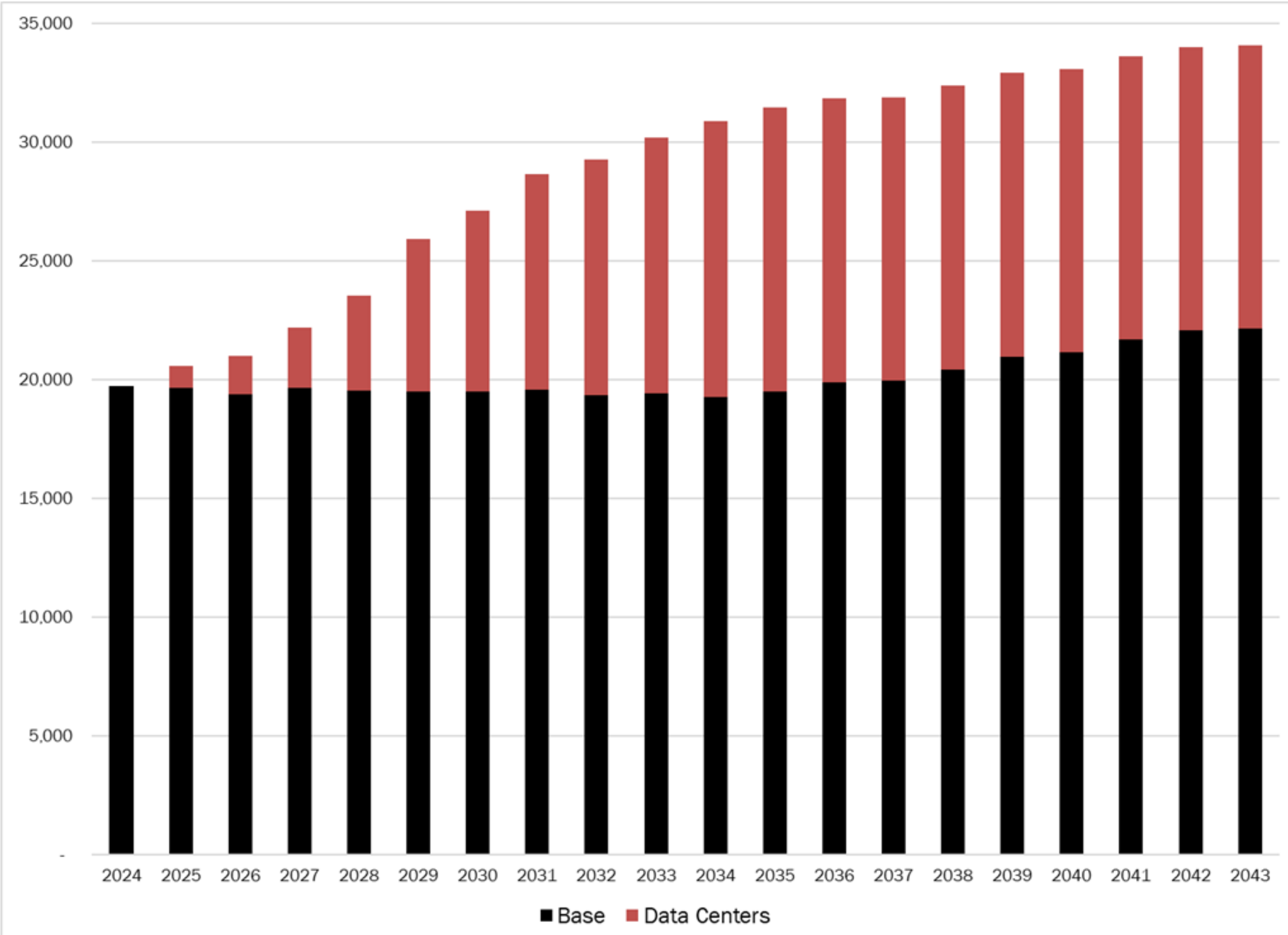


Figure 3-8. Indiana Peak Demand (Summer) (MW) Base Scenario vs. Data Center Scenario



Resource and Price Implications of Data Center Scenario

The data center loads were layered onto the base forecast and then run through the Aurora model in order to obtain a revised resource build. Table 3-9 shows the statewide resource plan for the data center scenario. The model selected a significantly larger amount of natural gas resources than in the base scenario and fewer renewable resources; wind is still maximized, but the build limit is reached much earlier than in the base and no solar is selected in this scenario unlike in the base. The wind build limit was kept the same in order to facilitate a direct comparison to the base forecast. Relaxing that constraint would likely increase the amount of wind built and therefore reduce the amount of natural gas resources selected somewhat.

Indiana Michigan Power (I&M) and Northern Indiana Public Service Company (NIPSCO) currently have the largest amount of modeled data centers in the state. I&M received approval from the IURC in February 2025 for the large load tariff settlement filed in late 2024. This tariff structure allows I&M to meet the load growth from data centers while protecting other customers from the costs of serving that load. NIPSCO obtained approval from the IURC in September 2025 to establish a subsidiary called GenCo that will provide power to data centers. The purpose of this structure, similar to what I&M accomplishes through their large load tariff, is to allow NIPSCO to meet the growth due to data centers while also protecting other customers from those costs. NIPSCO intends to purchase the power to serve the data centers through a power purchase agreement (PPA) with GenCo. It should be noted, however, that the resource build in SUFG's data center scenario shown in Table 3-9 includes resources built by NIPSCO since the details of the actual PPA are not known at this time.

Table 3-9. Indiana Selected Resources for Data Center Scenario in MW

Year	Data Center Scenario						
	CT	CC	Wind	Solar	BESS	SMR	Total
2024	0	0	5,290	0	0	0	5,290
2025	0	564	5,290	0	0	0	5,854
2026	0	1,860	5,290	0	0	0	7,150
2027	0	2,882	5,290	0	0	0	8,172
2028	0	2,929	8,359	0	0	0	11,289
2029	0	6,957	12,000	0	0	0	18,957
2030	0	8,867	12,000	0	0	0	20,867
2031	0	11,261	12,000	0	0	0	23,261
2032	0	15,034	12,000	0	0	0	27,034
2033	0	15,163	12,000	0	0	0	27,163
2034	0	17,140	12,000	0	0	0	29,140
2035	0	17,999	12,000	0	0	0	29,999
2036	0	18,238	12,000	0	0	0	30,238
2037	0	18,639	12,000	0	0	0	30,639
2038	86	20,811	12,000	0	0	0	32,897
2039	367	21,286	12,000	0	0	0	33,654
2040	559	21,575	12,000	0	0	0	34,133
2041	826	22,181	12,000	0	0	0	35,007
2042	826	22,747	12,000	0	0	0	35,574
2043	1,074	23,882	12,000	0	0	0	36,957

The data center scenario was not iterated through the rate making model and the entire modeling system[8] (discussed in detail in Chapter 2), so a rate forecast was not produced for this scenario; however, a comparison of the net present value (NPV) of the 20-year total system cost from Aurora between the base forecast and the data center scenario reveals that the additional required resources necessary to meet the modeled data center load increases the NPV of the total system cost by 57 percent.

This total system cost from Aurora includes capital costs of new builds and ongoing operating, maintenance, and fuel costs for existing and new resources, net of any benefits such as revenue from market sales, energy savings, and tax credits. This total system cost from Aurora does not include costs associated with depreciation and return on equity of existing resources, the existing transmission and distribution system, or existing debt. These are all sunk costs and therefore are not

[8] The SUFG rate model allocates the cost of generating resources to all customer classes, so the cost of the additional resources needed to meet the data center load would affect the rates for all sectors. These rates would then flow through to the sector level energy models in the next iteration impacting the demand forecast in an undesirable fashion.

included in the optimization model. Furthermore, costs associated with any transmission and distribution additions or upgrades required to serve the data center load are not included in this analysis. Thus, it is important to understand what is and what is not included in the total system cost coming out of Aurora and that the 57 percent increase only represents an increase in a portion of the total costs rates would ultimately be based on.

It is also important to note that these increases in system costs do not necessarily translate into increases in electric rates. The addition of data centers increases resource needs and costs, but those costs are also spread over a much larger number of megawatt-hours. Electric rates can therefore increase, decrease, or remain relatively flat depending on the relative change in electricity output and revenue requirements.

The data center scenario should be viewed as a starting point and other data center scenarios could be modeled in the future with different assumptions about inputs such as load amounts, timing, ramp rates, and load factors.

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Chapter 4

Major Forecast Inputs and Assumptions

Introduction

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

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

Macroeconomic Scenarios

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

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

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

Economic Activity Projections

National and state economic projections are produced by CEMR twice each year. For this forecast, SUFG adopted CEMR's February 2025 economic projections as its base scenario. CEMR also produced high and low growth alternatives to the base projection for SUFG's use in the high and low scenarios.

The CEMR long-run projections are based on its macroeconomic models of the U.S. and Indiana. The CEMR model of the U.S. economy is a quarterly econometric model with about 260 variables. Of these about 50 are exogenous – that is, they are set by the forecaster outside the model. Many of these are policy-related (for example, tax rates and government spending components). There are about 100 behavioral variables that are determined by estimated statistical equations. These include equations for the major components of aggregate demand, employment and unemployment, key price and wage rate variables, and components of national income. The remainder of the variables in the model are set by identities – that is, by definitional relationships between other variables in the model. The model involves simultaneous interactions between and among behavioral variables and those set by identities. Many of the behavioral equations are non-linear requiring the model to be solved using an iterative procedure. A satellite model generates forecasts of national employment at an industry level. This model has about 55 variables of which about 25 come from the main U.S. model.

The Indiana model is less complex and has less interaction between variables. It is designed mainly to produce forecasts of state employment both in total and at the industry level. The model also forecasts state income and its main components. The equations of the model use variables from the U.S. satellite model (including variables from the main U.S. model) as inputs.

Both the U.S. models and the Indiana model are used on a quarterly schedule to produce short-run forecasts. These forecasts have horizons of about four years, and they attempt to capture business cycle fluctuations in the economy.

However, when used for long-run purposes, the CEMR’s goal is to produce a projection that reflects underlying trends in the economy without cyclical influences. It is achieved via modifications to the U.S. and state model so that the resulting projection depends largely on supply-side factors that determine the average level of economic growth – in particular, growth in the labor supply and growth in productivity. The former is dependent on demographic trends for which national and state population projections from the federal Bureau of the Census and the IBRC were used. Productivity trends are treated as exogenous. The long-run procedure also includes a model for state gross domestic product at the industry level.

The main exogenous assumptions in the national projections used in the CEMR forecast, as cited from “Long-Range Projections 2024-2045” [CEMR, 2025] are:

“We assume that the federal payroll tax rate increases through the entire projection by a total of 2.8 percent. Federal grants to state and local governments are assumed to grow at an average rate of 4.6 percent over the projection period. Growth in government purchases is low. This produces a reduction in the federal government deficit from 6.3 percent of GDP in 2024 to 3.4 percent in 2045. The average for this period is 4.8 percent compared with 2.8 percent over the period 1960-1999.

State and local tax rates are stable over the projection period. This results in these governments having budgets that are close to being in balance.

Real exports are assumed to grow at about 3.7 percent through the projection period, somewhat above the growth of real imports. The result is a relatively stable real net export deficit that declines from 4.5 percent of real GDP in 2024 to 4.3 percent in 2045.”

As a result of these assumptions, real GDP for the U.S. economy is projected to grow at a compound annual growth rate (CAGR) of 2.09 percent and U.S. employment grows at a CAGR of 0.68 percent over the 2024 to 2043 period.

In Indiana, total employment is projected to grow at a CAGR of 0.60 percent from 2024 through 2043. The key Indiana economic projections are:

Real personal income (a residential sector model driver) is expected to grow with a CAGR of 1.69 percent.

Non-manufacturing employment (the commercial sector model driver) is expected to grow with a CAGR of 0.79 percent.

Despite a small decline in manufacturing employment (at a CAGR of -0.65 percent for the period of 2024-2043), manufacturing GSP (the industrial sector model driver) is expected to rise at a CAGR of 1.83 percent as gains in productivity far outpace the drop 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 4-1. It should be noted that some historical data has been revised by CEMR based on changes from federal sources, particularly the Bureau of Economic Analysis.

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

	Short-Run History for Selected Recent Periods					Long-Run Forecast		
						Feb 2021	Feb 2023	Feb 2025
	2000-2005	2005-2010	2010-2015	2015-2020	2020-2024	2020-2039	2022-2041	2024-2043
United States								
Real Personal Income	1.92	1.56	2.77	3.35	1.62	2.14	2.03	2.33
Total Employment	0.30	-0.56	1.70	0.05	2.77	0.89	0.68	0.68
Real Gross Domestic Product	2.55	0.98	2.29	1.52	3.56	2.45	1.92	2.09
Personal Consumer Expenditure Deflator	2.15	1.96	1.46	1.46	4.22	2.17	2.18	1.96
Indiana								
Real Personal Income	0.70	1.25	2.38	3.18	1.70	1.45	1.24	1.69
Employment								
Total Establishment	-0.30	-1.11	1.62	-0.27	2.36	0.88	0.57	0.60
Manufacturing	-2.99	-4.78	3.02	-0.52	1.12	-0.52	-0.59	-0.65
Non-Manufacturing	0.46	-0.04	1.31	-0.36	2.51	1.11	0.77	0.79
Real Gross State Product								
Total	1.89	0.92	1.25	1.07	3.68	2.29	1.86	2.14
Manufacturing	2.20	2.86	-0.49	0.90	4.94	1.44	1.14	1.83
Non-Manufacturing	1.78	0.22	1.90	1.12	3.23	2.57	2.11	2.24

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"
Note: The growth rates for manufacturing GSP and total GSP in the 2021 forecast reflect adjustments made by SUFG to the transportation equipment industry forecast. In the 2023 and 2025 forecasts, no such adjustments were made, as they were deemed unnecessary.

To capture some of the uncertainty in energy forecasting, CEMR provided 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. In the high growth alternative, the Indiana CAGR for the period of 2024-2043 for real personal income is increased by about 0.30 (to 1.99 percent), non-manufacturing employment growth increases 0.09 percent (to 0.88 percent), while Indiana real manufacturing GSP growth is increased by 0.72 percent (to 2.55 percent). In the low growth alternative, the average growth rates of real personal income, non-manufacturing employment, and real manufacturing GSP are reduced by similar amounts (to 1.40, 0.69 and 1.14 percent, respectively).

The data center scenario is layered onto the base scenario; therefore, it uses the same economic forecast as the base forecast. CEMR's economic projections (base, low, and high) do not explicitly account for the potential impacts of data center developments. The rapid and unpredictable pace of data center expansion makes it challenging to capture these impacts within conventional economic activity projections.

Demographic Projections

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

The population projections utilized in SUFG's electricity forecasts were obtained from the Indiana Business Research Center at Indiana University (IBRC) in February 2025. According to the IBRC, Indiana's total population is projected to grow at a CAGR of 0.17 percent between 2025 and 2045. These projections are based on 2020 population estimates from the U.S. Census Bureau and include forecasts by age group.

The fastest-growing segments are seniors aged 65 and older (CAGR of 0.71 percent) and older adults aged 45–64 (CAGR of 0.32 percent). In contrast, the population of school-age (5–19) is projected to decline with a CAGR of -0.15 percent, while college-age (20–24) is expected to decline with a CAGR of -0.42 percent. The preschool-aged group (0–4) is projected to experience minimal growth (CAGR of 0.01 percent), and young adults aged 25–44 are expected to grow modestly (CAGR of 0.05 percent).

Overall, Indiana's population growth is expected to remain relatively low during the projection period. This is largely due to minimal growth among young adults of childbearing age and more substantial increases among older age groups, which have higher mortality rates.

Indiana population growth has slowed markedly in recent years. The number of people over age 65 (the groups with fewer occupants per household) is projected to grow more rapidly than the younger population. Thus, the number of people per household is projected to decline and household formations are expected to grow more rapidly than total population.

The historical growth of household formations (number of residential customers) has slowed significantly from slightly over 2 percent during the late 1960s and early 1970s to 0.82 percent from 2013-2023. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of about 1.21 percent over the forecast period.

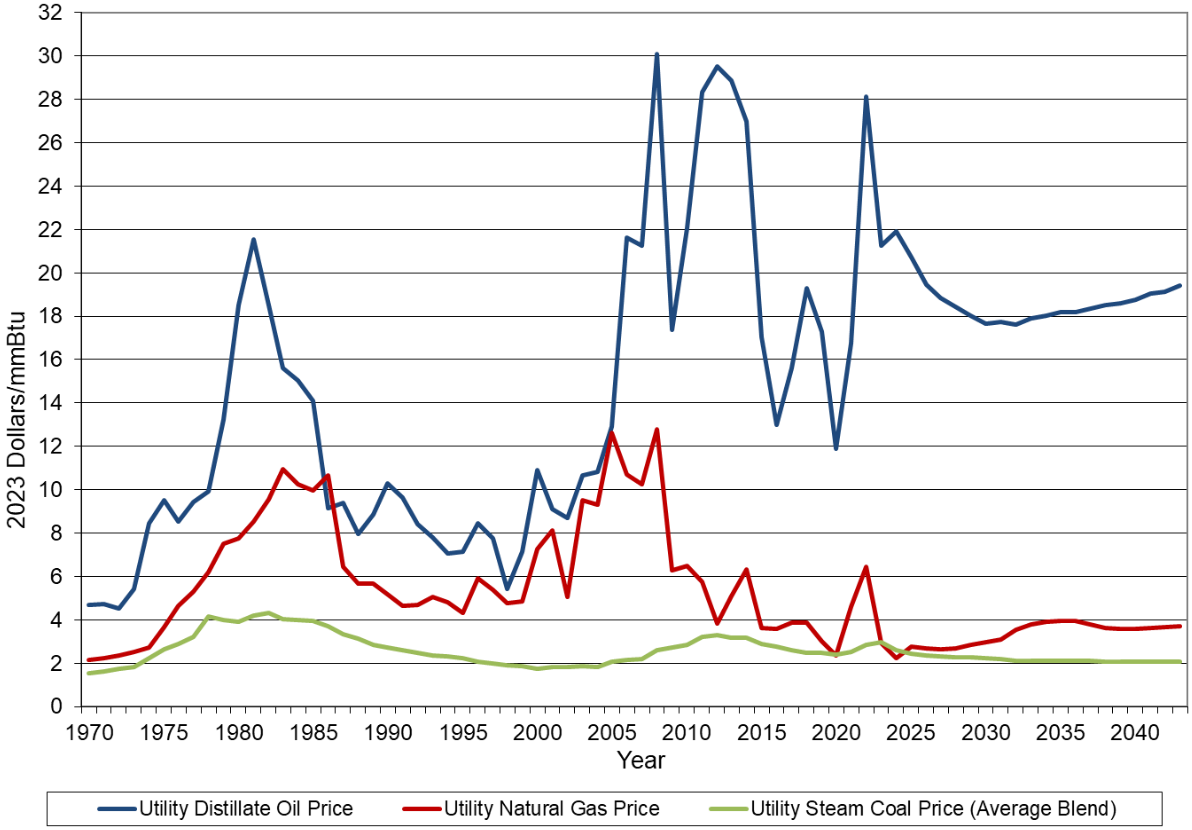
Fossil Fuel Price Projections

The prices of fossil fuels such as coal, natural gas, and oil affect electricity demand in separate and opposing ways. To the extent that any of these fuels are used to generate electricity, they are a determinant of average electricity prices. About 40% of the state's electricity was generated from coal in 2023, while 34% was generated from natural gas [IURC, 2025]. Thus, when coal or natural gas 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 change, the impacts on electricity demand are somewhat offsetting. The net impact of these opposing forces depends on their impact on utility costs, the responsiveness of customer demand to electricity price changes, and the availability and competitiveness of fossil fuels in the end-use services markets. The SUFG modeling system is designed to simulate each of these effects as well as the dynamic interactions among all effects.

SUFG's modeling system incorporates separate fuel price projections for utility, industrial, commercial, and residential sectors. Therefore, SUFG uses four distinct natural gas price projections (one for each sector). Similarly, four distinct oil price projections are used. Coal price projections are included for the utility and industrial sectors only. In this forecast, SUFG has used May 2025 fossil fuel price projections from EIA for the East North Central Region [EIA, 2025]. All projections are in terms of real prices (2023 dollars/mmBtu), i.e., projections with the effects of inflation removed. The general patterns of the fossil fuel price projections are:

- Coal price projections are relatively flat in real terms throughout the entire forecast horizon (around $2/mmBtu) as coal consumption decreases due to more natural gas and renewable generation observed in the electric power sector.
- Natural gas prices decreased significantly from 2008 to 2012. Prices then rebounded slightly in 2013 and 2014 before another dip since 2015. During the pandemic, the price hit the low level around $2/mmBtu, but then rebounded to exceed the pre-pandemic level in 2022. The natural gas price is projected to gradually increase to around $4/mmBtu in 2035. Prices are expected to remain flat at that level through 2043.
- Distillate oil prices also decreased significantly in 2009 from the high prices of 2008. Prices then rebounded significantly through 2012 before declining again in 2013, followed by substantial decreases in 2016. Prices rebounded quickly in 2017 and 2018 and then hit another low during the pandemic. Prices rebounded to around $28/mmBtu in 2022. Distillate oil prices are projected to decline to approximately $18/MMBtu by 2028. After that, prices are expected to rise gradually, reaching close to $20/MMBtu by 2043. The fossil fuel price projections for the utility sector are presented in Figure 4-1.

Figure 4-1. Utility Real Fossil Fuel Prices in dollars/mmBtu (2023 Dollars)



Demand-Side Management, Energy Efficiency, and Demand Response

Demand-side management (DSM) refers to a variety of utility-sponsored programs designed to influence customer electricity usage in ways that produce desired changes in the utility's load shape, i.e., changes in the time pattern or magnitude of a utility's load. These programs include energy conservation programs that reduce overall consumption and load shifting programs that move demand from periods of high system demand to times when overall system demand is lower. SUFG considers separately the two components of DSM: energy efficiency (EE), which affects both energy and peak demand, and demand response (DR), which generally affects peak demand but has little impact on energy.

Incremental energy efficiency, which includes new programs and the expansion of existing programs, require adjustments to be made in the forecast. These adjustments are modeled within Aurora by effectively changing the utility's demand by the appropriate level of energy and peak demand for the EE program. EE programs that were in place in 2023 are considered to be embedded in the calibration data, so no adjustments are necessary.

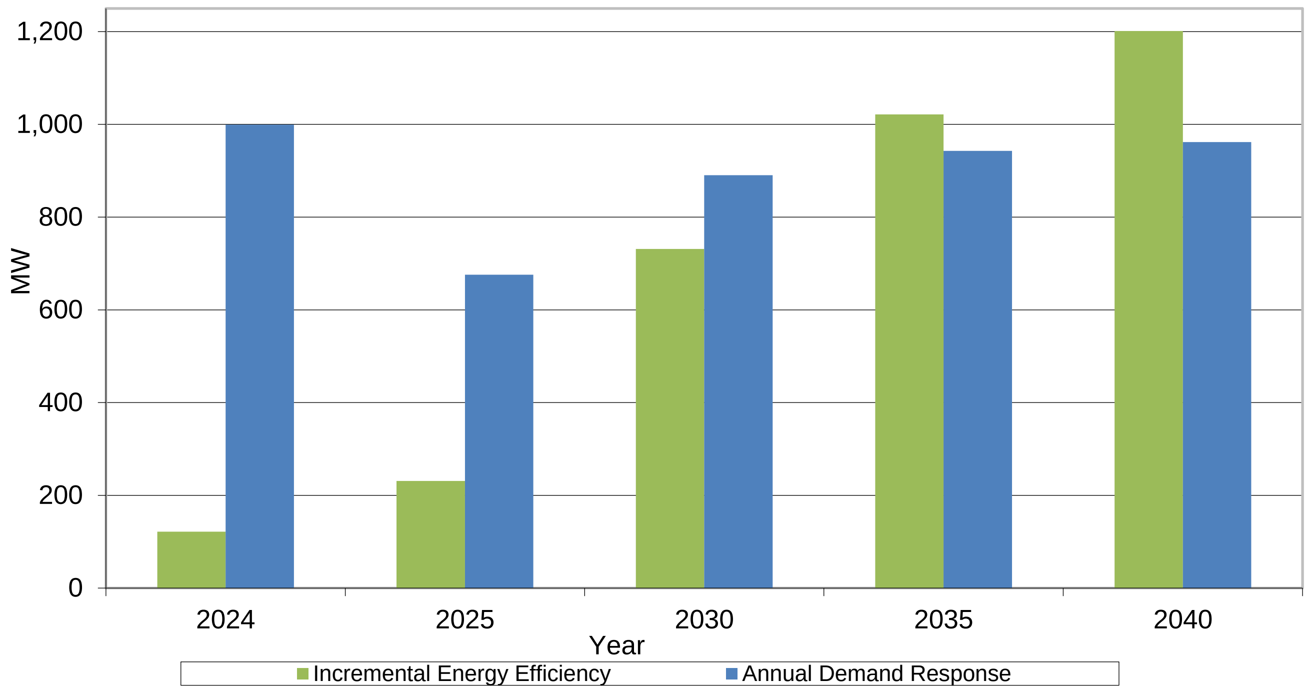
Demand response can include interruptible loads, such as large customers who agree to curtail a fixed amount of their demand during critical periods in exchange for more favorable rates, and direct load control, where the utility has the ability to directly turn off a customer's load for a specified amount of time. DR is typically treated differently from energy efficiency. In earlier forecasts, the amount of demand response was subtracted from the utility's peak demand in order to determine the amount of new capacity required. Beginning with the 2017 forecast, demand response is modeled within Aurora as a resource instead of as an after-the-fact adjustment.

Table 4-2 shows the peak demand reductions from embedded DSM in 2023 and from incremental EE and annual DR available in 2024 in Indiana. These estimates are derived from utility integrated resource plan (IRP) filings, from utility filings with the EIA, and from information collected by SUFG directly from the utilities. SUFG does not attempt to project additional DSM savings beyond those identified by the utilities at the time this report was prepared. It should be noted that SUFG does not advocate any specific means for meeting future resource requirements, with additional energy efficiency being one of the options available for meeting those requirements. Figure 4-2 shows projected values of peak demand reductions for incremental energy efficiency and demand response for 2024 and at five-year intervals starting in the year 2025. This forecast reflects higher levels of utility-sponsored EE (about 1,200 MW of savings late in the forecast period as compared to about 940 MW in the 2023 forecast), while DR peak demand reductions are also higher. The more aggressive DSM programs have a moderate impact on the forecasted energy use, particularly in the residential and commercial sectors.

Table 4-2. 2023 Embedded DSM and 2024 Incremental Peak Demand Reductions from Energy Efficiency and Annual Demand Response Programs in MW

2023 Embedded DSM	2024 Incremental Energy Efficiency	2024 Annual Demand Response
359	122	999

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



Changes in Forecast Drivers from the 2023 Forecast

The SUFG forecast requires exogenous economic assumptions to project electric energy sales, peak demand, and prices. Fluctuations in the national and state economies therefore have direct effects on the forecast. This section compares the CEMR's projections used in SUFG's 2023 and 2025 forecasts.

Tables 4-3 through 4-5 provide comparisons between the two projections. Selected economic variables are reported annually from 2019 through 2024 and for 2025, 2030, 2035, 2040, and the last year of the forecast period 2043. The tables show long-run projections of real values and percentage change at annual rates for non-manufacturing employment, real personal income, and total real manufacturing GSP. The tables also show the percentage change between CEMR2023 and CEMR2025. Figures 4-3 through 4-5 show long-run projections of real values for the same selected economic variables from 2019 through 2045. Some of the historical values differ between the two projections because of data revisions and the use of chain-weighted price indices and deflators.

Non-manufacturing Employment

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

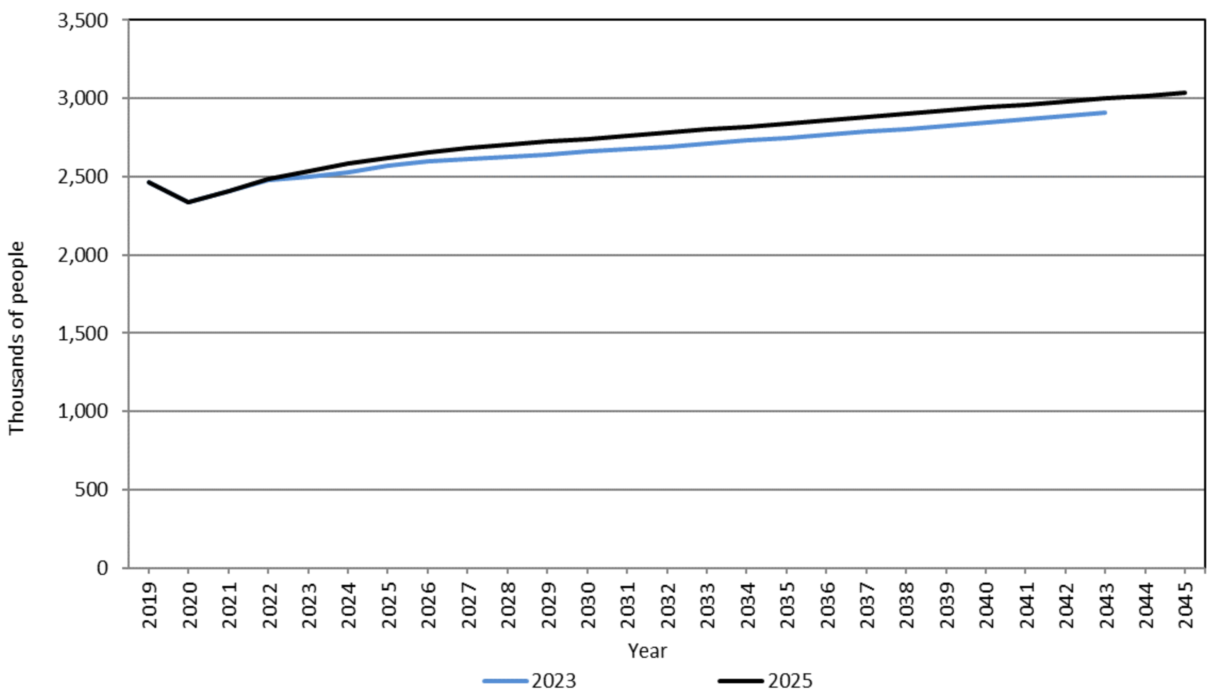
Table 4-3 and Figure 4-3 show that the current CEMR projection for non-manufacturing employment is slightly higher than that in the 2023 projection.

Table 4-3. 2023 and 2025 CEMR Projections for Indiana Non-manufacturing Employment

	Year										
	2019	2020	2021	2022	2023	2024	2025	2030	2035	2040	2043
	Thousands of persons										
CEMR 2023	2,467.05 (0.72)	2,339.08 (-5.19)	2,408.28 (2.96)	2,478.51 (2.92)	2,498.84 (0.82)	2,526.29 (1.10)	2,573.04 (1.85)	2,658.29 (0.61)	2,748.45 (0.68)	2,847.15 (0.74)	2,910.72 (0.74)
CEMR 2025	2,466.98 (0.71)	2,340.09 (-5.14)	2,405.38 (2.79)	2,486.98 (3.39)	2,537.73 (2.04)	2,584.42 (1.84)	2,620.30 (1.39)	2,742.98 (0.70)	2,841.76 (0.75)	2,941.81 (0.66)	2,998.74 (0.62)
Percentage change between two projections	0.00	0.04	-0.12	0.34	1.56	2.30	1.84	3.19	3.40	3.32	3.02

Sources: SUFG Forecast Modeling System and various CEMR “Long-Range Projections”
Note: Numbers in parentheses indicate percentage change from the previous year of the same projection.

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



Real Personal Income

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

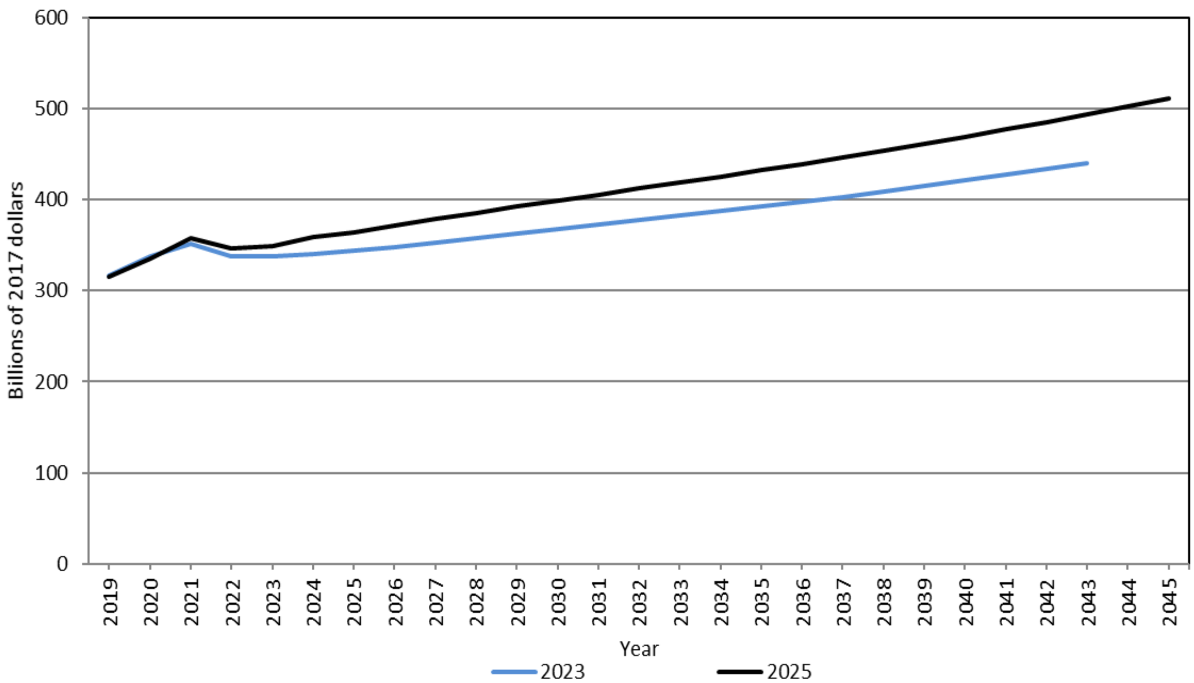
Table 4-4 and Figure 4-4 show the CEMR projections of real personal income. CEMR2025 has a higher projection for real personal income over the forecast period.

Figure 4-4 illustrates that the CEMR2025 real personal income is projected to be higher than that in CEMR2023 over the forecast horizon.

Table 4-4. 2023 and 2025 CEMR Projections for Indiana Real Personal Income

	Year										
	2019	2020	2021	2022	2023	2024	2025	2030	2035	2040	2043
	Billions of 2017 $										
CEMR 2023	317.18 (2.86)	337.30 (6.34)	352.08 (4.38)	338.26 3.93	338.31 (0.01)	340.10 (0.53)	343.61 (1.03)	367.50 (1.34)	392.52 (1.32)	421.05 (1.48)	440.03 (1.48)
CEMR 2025	315.33 (2.77)	335.79 (6.49)	358.40 (6.74)	347.04 3.17	348.79 (0.51)	359.18 (2.98)	364.46 (1.47)	399.18 (1.69)	432.35 (1.65)	469.53 (1.67)	493.94 (1.71)
Percentage change between two projections	-0.58	-0.45	1.80	2.59	3.10	5.61	6.07	8.62	10.15	11.52	12.25
Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections" Note: Numbers in parentheses indicate percentage change from the previous year of the same projection.											

Figure 4-4. Indiana Real Personal Income (billions of 2017 dollars)



Real Manufacturing Gross State Product

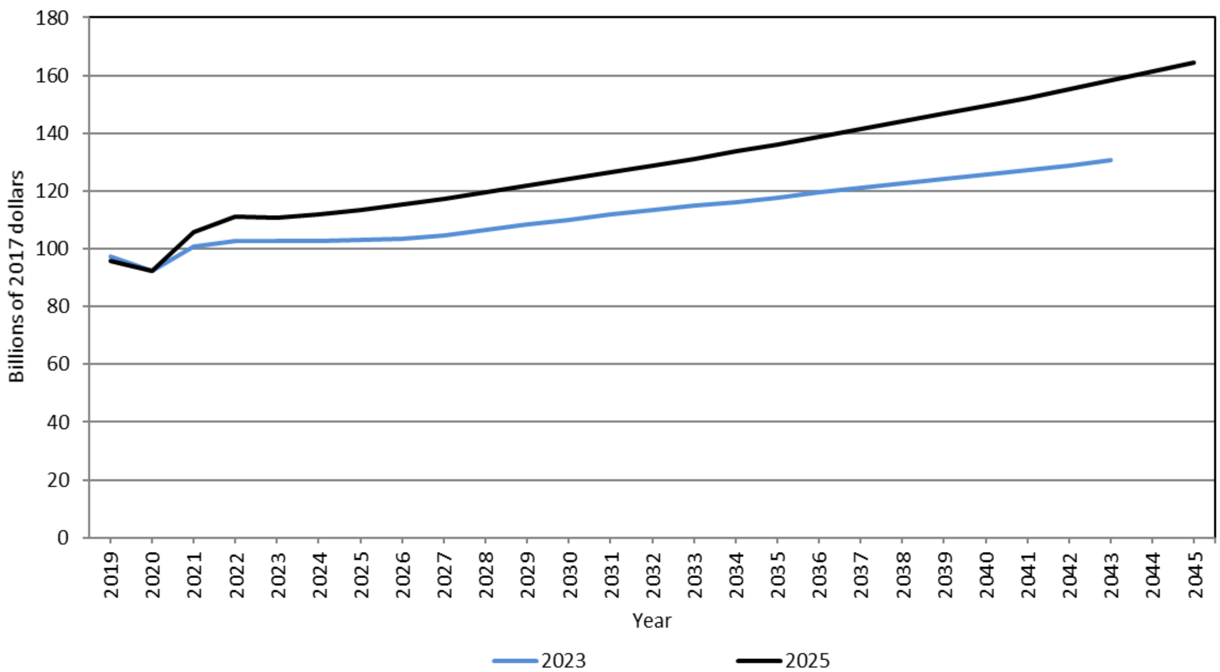
Changes in manufacturing GSP will have significant implications for electricity use in the industrial sector. Table 4-5 and Figure 4-5 show the CEMR projections for real manufacturing GSP. CEMR2025 provides a substantially higher manufacturing GSP forecast compared to CEMR2023. Growth is mainly driven by productivity improvements and specific industry expansions, such as automobile & parts manufacturing and semiconductor manufacturing.

Table 4-5. 2023 and 2025 CEMR Projections for Indiana Real Manufacturing GSP

	Year										
	2019	2020	2021	2022	2023	2024	2025	2030	2035	2040	2043
	Billions of 2017 $										
CEMR 2023	97.40 (-0.15)	92.25 (-5.28)	100.92 (9.39)	102.63 (1.70)	102.77 (0.13)	102.81 (0.05)	102.89 (0.07)	110.01 (1.59)	117.83 (1.32)	125.67 (1.27)	130.61 (1.29)
CEMR 2025	95.78 (-0.83)	92.39 (-3.54)	105.64 (14.35)	111.08 (5.14)	110.68 (-0.35)	112.06 (1.25)	113.51 (1.29)	124.34 (1.92)	136.06 (1.85)	149.43 (1.88)	158.29 (1.97)
Percentage change between two projections	-1.66	0.15	4.68	8.23	7.70	9.00	10.32	13.02	15.47	18.90	21.19

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"
Notes: Numbers in parentheses indicate percentage change from the previous year of the same projection

Figure 4-5. Indiana Real Manufacturing GSP (billions of 2017 dollars)



Transportation Equipment Industry

The transportation equipment industry, including automobile and auto parts manufacturing, accounts for a considerable portion of the total manufacturing GSP in Indiana. In 2023, this sector represented 34 percent of the total real value of products manufactured in the state.

SUFG deemed that CEMR's forecasts showed too much growth over the long term for this sector for CEMR2021 and before, so those forecasts were tempered. However, beginning in 2023 forecast, SUFG did not make adjustments to the transportation equipment industry due to new developments in this area in the state. Indiana has recently made significant strides in EV manufacturing, especially EV battery manufacturing facility, positioning itself as a burgeoning hub for EV-related industries. The CEMR2025 projection indicates a CAGR of 3.30 percent for the forecast period of 2024-2043.

Table 4-6 shows projected growth rates, actual values and percentage rate changes for the transportation equipment GSP for both CEMR2023 and CEMR2025. The industry is projected to keep growing for the entire forecast period. Growth over time in CEMR2025 is substantially higher than that in the CEMR2023 projection.

Table 4-6. 2023 and 2025 CEMR Projections for Indiana Real Transportation Equipment GSP

	Year										
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**	**2040**	**2043**
	Billions of 2017 $										
CEMR 2023	17.64	16.77	22.99	23.54	23.69	24.08	24.48	27.88	31.41	35.21	37.69
	(0.76)	(-4.91)	(37.06)	(2.40)	(0.64)	(1.64)	(1.68)	(2.61)	(2.35)	(2.27)	(2.28)
CEMR 2025	19.92	18.68	24.68	28.41	24.98	25.09	25.69	30.52	35.85	42.17	46.49
	(0.76)	(-6.23)	(32.15)	(15.10)	(-12.08)	(0.47)	(2.37)	(3.42)	(3.29)	(3.27)	(3.33)
Percentage change between two projections	12.93	11.36	7.37	20.69	5.43	4.22	4.93	9.45	14.13	19.75	23.35

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

Note: Numbers in parentheses indicate percentage change from the previous year of the same projection.

Primary Metals Industry

While the primary metals industry, including production of steel and aluminum, represented approximately 15 percent of Indiana manufacturing GSP in 2023, it accounted for 29 percent of the state's industrial electricity sales.

Table 4-7 compares the CEMR projections for 2023 and 2025 for the primary metals industry. The primary metals industry is projected to be decreasing over the forecast period of 2024-2043. However, the CEMR2025 projection for the primary metals industry is still much higher than that in the CEMR2023. In 2043, the projected GSP level for the primary metals industry in the CEMR2025 is about double the level in the CEMR2023, which is mainly driven by revisions of most recent historical data.

Table 4-7. 2023 and 2025 CEMR Projections for Indiana Real Primary Metals GSP

	Year										
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**	**2040**	**2043**
	Billions of 2017 $										
CEMR 2023	11.36	11.86	11.69	11.15	10.58	9.85	9.12	7.83	7.62	7.36	7.20
	(-0.25)	(4.40)	(-1.42)	(-4.64)	(-5.08)	(-6.94)	(-7.43)	(-0.19)	(-0.63)	(-0.75)	(-0.76)
CEMR 2025	9.49	8.68	9.97	12.07	14.03	14.14	14.09	14.17	14.09	14.01	13.96
	(3.34)	(-0.86)	(14.89)	(21.04)	(16.24)	(0.83)	(-0.36)	(0.03)	(-0.11)	(-0.15)	(-0.10)
Percentage change between two projections	-16.41	-26.82	-14.71	8.25	32.57	43.64	54.61	81.07	84.84	90.32	93.96

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

Note: Numbers in parentheses indicate percentage change from the previous year of the same projection.

Forecast Uncertainty

There are three sources of uncertainty in any energy forecast:

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

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

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

In practice, virtually all models are less than perfect. Non-stochastic model error results from specification errors, measurement errors and/or use of inappropriate estimation methods. SUFG is committed to identifying and correcting potential errors in model specification, data measurement, and appropriate estimation methods.

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Chapter 5

Residential Electricity Sales

Overview

There are two general modeling approaches to project residential electricity sales: econometric and end-use models. The econometric approach relates historical energy consumption to key drivers such as income, population, prices, and weather, capturing observed statistical relationships between electricity use and economic and demographic variables. The end-use approach builds electricity demand from the bottom up, estimating energy use for specific housing characteristics, appliance efficiency, and end uses such as cooling, heating, and lighting. Together, these approaches provide both economic and engineering perspectives on residential energy use.

SUFG adopted the proprietary end-use model Residential Energy Demand Model System (REDMS) beginning with the 2011 forecast as the residential sector model for projecting electricity sales for Indiana's investor-owned utilities (IOUs). REDMS is actively supported by the vendor, Jerry Jackson Associates, with the model being re-estimated in 2019. Econometric models developed by SUFG are used for the not-for-profit utilities (NFPs), where data availability and model scope make it more suitable.

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. Over time, these market factors have exhibited distinctly different trends and, in each case, residential electricity sales growth has reflected the change in market conditions.

The explosion in residential electricity sales during the decade before the Organization of Petroleum Exporting Countries (OPEC) oil embargo in 1974 coincided with the economic stimuli of falling prices and rising incomes. This period was marked by a boom in the housing industry as the number of residences increased. In the decade following the embargo, the growth in residential electricity sales slowed dramatically. Except for some softening in electricity prices during the late-1970s and early-1980s, real electricity prices climbed at approximately the same rate during the post-embargo era as they had fallen during the pre-embargo era. Growth in real household income was miniscule and the housing market went from boom to bust, averaging only half the growth of the pre-embargo period. This turnaround in economic conditions and electricity prices was reflected in a dramatic decline in the growth of residential electricity sales to around two percent per year as opposed to nearly nine percent previously. Events turned again during the mid-1980s. Real household income grew faster than in the pre-embargo era and real electricity prices declined. Growth in the number of households was largely unchanged and annual electricity sales increased slightly during this period.

Several market factors contributed to the small increase in sales growth between the post-embargo and 2000s. 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. Plentiful supply and falling natural gas prices from mid-1980s to 2000 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 were nearing full saturation.

For the early-2000s period, residential household growth decreased slightly, real electric rates continued to decline, but the growth in personal income, while positive, slowed markedly. Despite the slow growth in income, electricity sales continued to grow at roughly the rate observed during the mid-1980s to late-1990s period.

Beginning in the mid-2000s, real electricity prices increased reversing the trend of the previous twenty years. These rising electricity prices coupled with the effects of the economic downturn in the late-2000s, and increased efficiency have resulted in much lower growth in electricity sales. Growth of the number of households slowed to about one-fourth the rate observed over the preceding twenty years. Real household income slowly increased over this period. The net effect of these changes was to reduce the electricity sales growth rate to essentially flat over the period.

By the 2010s, Indiana's residential electricity demand showed minimal gains, effectively unchanged over the decade following the 2007-09 Great Recession. This reflected a slow economic recovery and efficiency gains through utility energy-efficiency programs (e.g., appliance upgrades, lighting, and HVAC) that helped moderate load growth. During this decade, real residential electricity prices in Indiana trended upward as utilities absorbed costs tied to compliance with federal environmental regulations and investments in generation and environmental-control infrastructure. Meanwhile, Indiana's generation mix began diversifying, with the state increasing its wind capacity and producing an increasing share of electricity from wind.

In the 2020s, Indiana's residential electricity prices continued to rise as utilities invested in grid upgrades, the clean-energy transition, and infrastructure resilience. The COVID-19 pandemic temporarily altered load patterns—more time spent at home generally increased residential usage. As the economy reopened, residential load stabilized at levels roughly similar to the pre-pandemic period. At the same time, plant retirements or retrofits (especially among coal units), expansion of renewables, and supply-chain pressures maintained upward cost pressures. Overall, the residential sector in Indiana during the 2020s reflects a slow, but steady shift toward cleaner generation, with rate pressures driven by ongoing infrastructure investment and modernization.

Model Description

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

Figure 5-1 depicts the structure of the residential end-use model. As the figure shows, REDMS uses a disaggregated capital stock approach to forecast energy use. Energy use is viewed as a derived demand in which electricity and other fuels are inputs, along with energy using equipment and building envelopes, in the production of end-use services.

The disaggregation of energy demand is as important in the modeling of the residential sector as it is for modeling the commercial sector. REDMS divides residential dwellings among three dwelling types. It also divides energy use in each dwelling type among ten possible end uses, including a miscellaneous or residual use category. For end uses such as space heating, where non-electric fuels compete with electricity, REDMS further disaggregates energy use among fuel types. (This disaggregation scheme is illustrated at the top of Figure 5-1.) REDMS also divides dwellings among vintages, i.e., the year the dwelling was constructed, and simulates energy use for each vintage and dwelling type.

REDMS projects energy use for each dwelling vintage according to the following equation:

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

where

* = multiplication operator;
T = forecast year;
Q = energy demand for fuel i, end use k, dwelling type l and vintage t in the forecast year T;
t = dwelling vintage (year);
U = utilization, relative to some base year;
e = energy use index, kWh/year or Btu/year;
a = fraction of dwelling served by fuel i, end use k, and dwelling type l for dwelling additions of vintage t;
A = dwelling additions by vintage t and dwelling type l; and
d = fraction of dwellings of vintage t still standing in forecast year T.

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

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

Equipment standards are easily incorporated in REDMS' equipment choice sub-models. Besides efficiency and fuel choices, REDMS also models changes in equipment utilization, or intensity of use. For equipment that has not been added or replaced in the previous year, changes in equipment utilization are modeled using fuel-specific, short-run price elasticities and changes in fuel prices.

For new equipment installed in the current year, utilization depends on both equipment efficiency and fuel price. For example, a 10 percent improvement in efficiency and a 10 percent increase in fuel prices would have offsetting effects since the total cost of producing the end-use service is unchanged.

Figure 5-1. Structure of Residential End-Use Energy Modeling System

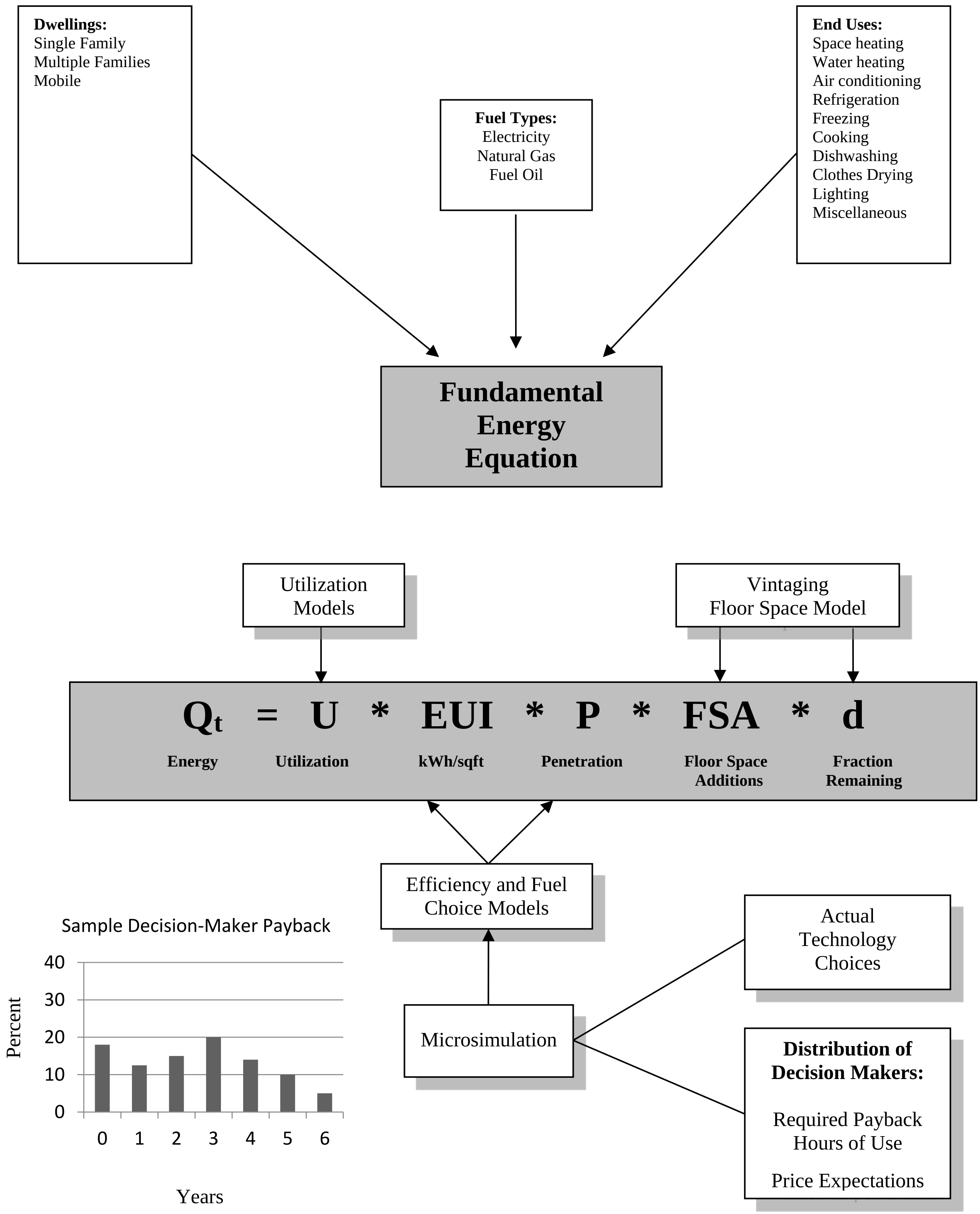


Table 5-1 provides the breakdown of the share of households in the service territories of the IOUs by type in the first column. The second column shows the share of electricity sales for the household types. The last three columns provide projected compound annual growth rates over the 2024-2043 forecast horizon for the number of households, electricity intensity as measured by annual sales per household, and growth in electricity sales.

Table 5-1. Selected Statistics for Indiana's Residential Sector (Without DSM and EV) (Percent)

Dwelling Type	Current Share of Total Households	Current Share of Electricity Sales	Forecast Growth in Number of Households	Forecast Growth in Electricity Intensity	Forecast Growth in Electricity Sales
Single Family	78	84	1.21	-0.51	0.70
Multi-Family	18	11	1.24	-0.46	0.78
Mobile Home	4	5	1.18	-0.74	0.44
Total	100	100	1.21	-0.51	0.70

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.

Model Sensitivities

The major economic drivers in the residential end-use model include dwellings (residential customers) and electricity prices. The sensitivity of the residential electricity use projection to changes in these variables was simulated one at a time by increasing each variable ten percent above a base scenario level and observing the change in electricity use. The results are shown in Table 5-2. Electricity consumption increases with the number of customers. As expected, electricity rate increases reduce electric consumption. Changes in natural gas prices, fuel oil prices, and personal income do not affect electricity consumption due in part to the structure of the model and in part due to the vendor's implementation of the model.

Competing fuels (gas and oil) could potentially affect electricity use through two mechanisms; retrofits and penetration in dwelling additions. Once an initial space heating (and subsequently water heating) fuel for a new dwelling is chosen, retrofits to an alternative fuel are generally precluded due to the cost hurdle of the capital expense of switching fuels. Such a fuel choice switch would require the addition of gas service and delivery, fuel oil storage and delivery, or an electrical service upgrade and wiring upgrades. During the period used for model calibration 2009-2018, penetration for most electric end uses were very consistent, with some of the less significant ones like cooking and dishwashers increasing. Electric space heating penetration was constant at 29 percent with natural gas and liquified petroleum gas (LPG) largely capturing the remainder. Real electricity prices increased, real natural gas prices decreased, and oil prices drifted upward with considerable volatility.

Personal income effects on fuel and efficiency choices are reflected in the decision makers' behavior through the micro-simulation modeling. On average, one would expect those decision makers facing active income or financial constraints to be the decision makers with shorter payback intervals and those without such constraints to have longer payback horizons. Also, a statistically significant relationship between end-use utilization and personal income could not be identified.

Table 5-2. Residential Model Long-Run Sensitivities

10 Percent Increase In	Causes This Percent Change in Electric Use
Number of Customers	10.6
Electric Rates	-3.0

Indiana Residential Electricity Sales Projections

Historical data as well as past and current projections are illustrated Table 5-3 and Figure 5-2. The growth rate for the current base projection of Indiana residential electricity sales is 1.81 percent, which is 0.53 percent higher than SUFG's 2023 projection of 1.28 percent. Historical and forecast values are provided in the Appendix of this report. Long-term patterns for the entire forecast horizon show that the current projection is below the 2023 forecast and very close to the 2021 forecast for the first seven years of the forecast horizon. In 2031, the current forecast starts increasing more rapidly and surpasses the 2023 forecast in 2039 and beyond. The significant growth in the second half of the forecast is primarily due to a higher electric vehicle forecast than in the previous forecast. Table 5-4 summarizes SUFG's base projections of residential electricity sales growth since the 2021 Forecast.

Table 5-4 breaks these projections down by the portion of the growth rate attributable to the growth in number of customers and growth in utilization per customer, with and without DSM. As the table shows, more than one half of projected sales growth is attributable to customer growth and the remainder to increases in utilization, which is the amount of energy used per household. Use per household increases because of increasing electrification, particularly electric vehicles. It can also be seen from the table that residential DSM cuts the sales growth rate by approximately one-eighth, reducing it from 2.09 percent to 1.81 percent.

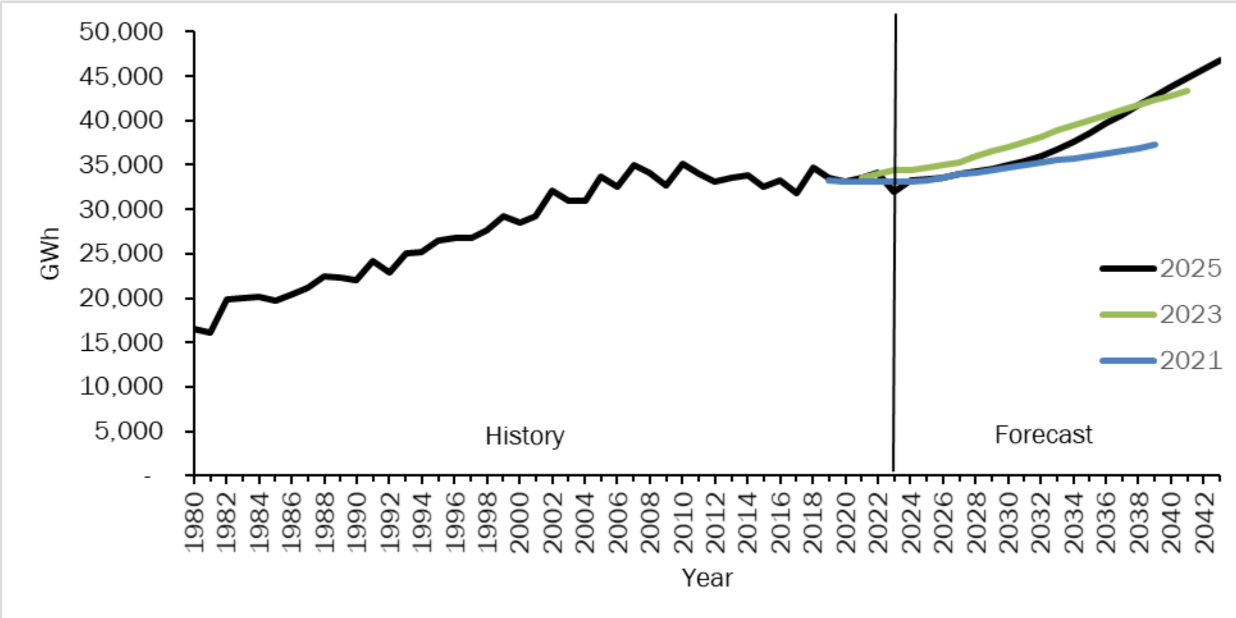
Table 5-5 shows the growth rates of the major residential drivers for the current scenarios and the 2021 and 2023 base case. Household formation is determined by two factors. Demographic projections are the primary determinant, with personal income having a smaller impact. The demographic projections in all five cases are very similar. While there are some small variations in personal income among the cases, they are not sufficiently large as to result in a significant difference in growth rates for the base and high scenarios.

As shown in Table 5-6 and Figure 5-3, the growth rates for the high and low residential scenarios are about 0.03 percent higher and 0.19 lower, respectively, than the base scenario. This difference is due to differences in the growth of household income and the number of electric vehicles.

Table 5-3. Indiana Residential Electricity Sales Compound Annual Growth Rates (CAGR) (Percent)

Forecast	CAGR	Time Period
2025	1.81	2024-2043
2023	1.28	2022-2041
2021	0.61	2020-2039

Figure 5-2. Indiana Residential Electricity Sales in GWh (Historical, Current, and Previous Forecasts)



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

Table 5-4. History of SUFG Residential Sector Growth Rates (Percent)

Forecast	Number of Households	Without DSM		With DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2025 SUFG Base (2024-2043)	1.21	0.88	2.09	0.60	1.81
2023 SUFG Base (2022-2041)	1.19	0.43	1.62	0.09	1.28
2021 SUFG Base (2020-2039)	1.14	-0.22	0.92	-0.53	0.61

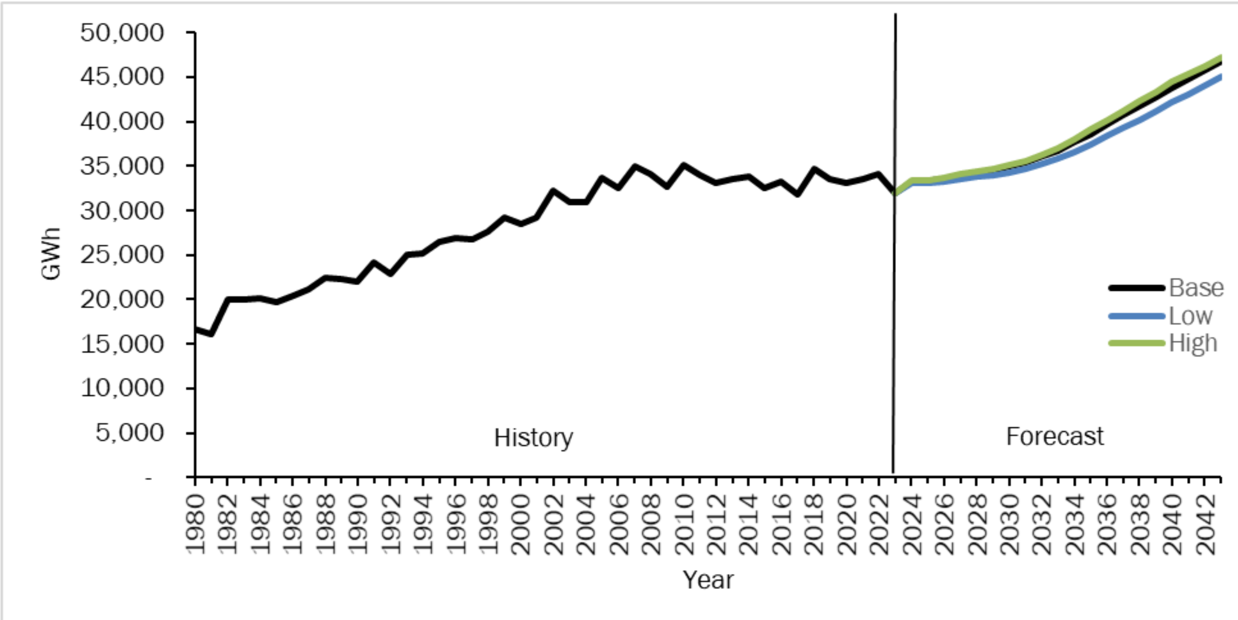
Table 5-5. Residential Model Growth Rates (Percent) for Selected Variables (2025 SUFG Scenarios and 2023 and 2021 Base Forecasts)

Forecast	Current Scenarios (2024-2043)			2023 Forecast (2022-2041)	2021 Forecast (2020-2039)
	Base	Low	High	Base	Base
Number of Households	1.21	1.17	1.22	1.19	1.14
Electric Rates	1.75	2.01	1.65	0.97	1.99

Table 5-6. Indiana Residential Electricity Sales Compound Annual Growth Rates (CAGR) by Scenario (Percent)

Forecast Period	Base	Low	High
2024-2043	1.81	1.62	1.84

Figure 5-3. Indiana Residential Electricity Sales by Scenario in GWh



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

Indiana Residential Electricity Price Projections

Historical values and current projections of residential electricity prices are shown in Figure 5-4, with growth rates provided in Table 5-7. In real terms, residential electricity prices declined from the mid-1980s until 2002. Real residential electricity prices have risen since 2002 due to increases in fuel costs and the installation of new emissions control equipment. SUFG projects real residential electricity prices to rise through 2033 before leveling off and slightly declining for the rest of the forecast period. SUFG's real price projections for most of the individual IOUs follow similar patterns as the state as a whole, but there are variations across the utilities. Historical and forecast prices are included in the Appendix of this report.

Figure 5-4. Indiana Residential Base Real Price Projections (2023 Dollars)

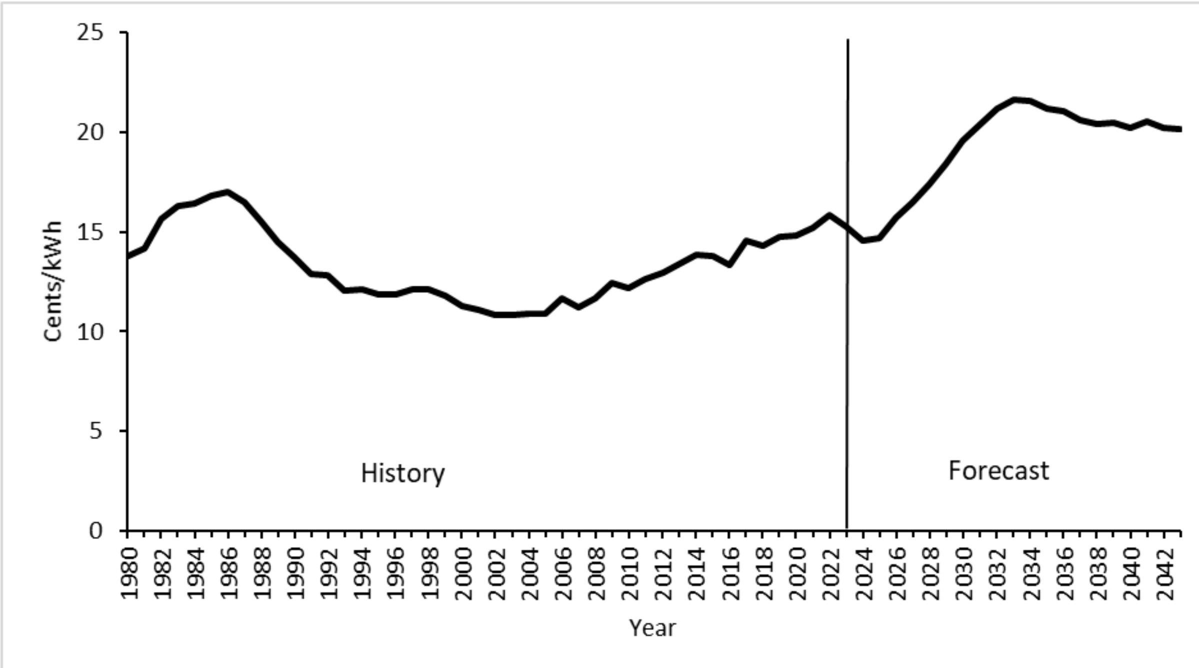


Table 5-7. Indiana Residential Base Real Price Compound Annual Growth Rates (CAGR) (Percent)

Selected Periods	CAGR
2002-2007	0.69
2007-2012	2.89
2012-2017	2.38
2017-2022	1.66
2022-2027	0.80
2027-2032	5.20
2032-2037	-0.58
2037-2043	-0.34
2024-2043	1.75

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

Chapter 6

Commercial Electricity Sales

Overview

There are two general modeling approaches to project commercial electricity sales: econometric and end-use models. The econometric approach relates historical energy consumption to key drivers such as non-manufacturing employment, population, electricity prices, and weather, capturing observed statistical relationships between electricity use and economic and demographic variables. The end-use approach builds electricity demand from the bottom up, estimating energy use for specific end uses such as cooling, refrigeration, and lighting by commercial building categories such as offices, hospitals and hotels. In this approach, electricity use per square foot varies across building types due to the specific equipment or operational needs of different businesses. Together, these approaches provide both economic and engineering perspectives on commercial energy use. SUFG adopted a proprietary end-use model, Commercial Energy Demand Modeling System (CEDMS) beginning with the 2011 forecast as the commercial sector model for projecting electricity sales for Indiana's investor-owned utilities (IOUs). Like the residential sector end-use model REDMS, CEDMS is actively supported by Jerry Jackson Associates, with the model being re-estimated in 2019. CEDMS uses commercial floor space by building types and estimates energy use for end uses within each building type. Econometric models developed by SUFG are used for the not-for-profit utilities (NFPs), where data availability and model scope make it more suitable.

Historical Perspective

Historical trends in commercial sector electricity sales have been distinctly different over the last six decades.

Changes in electric intensity, expressed as changes in electricity use per square foot (sqft) of energy-weighted floor space, arise from changes in building and equipment efficiencies as well as changes in equipment utilization, end-use saturations and new end uses. Electricity intensity increased rapidly during the era of cheap energy prior to the OPEC oil embargo. This trend was interrupted by the significant upward swing in electricity prices during the mid-1970s to mid-1980s period, which resulted in a decrease in energy intensity. As electricity prices fell again during the mid-1980s to late-1990s period, electricity intensity rose but at a slower rate than that observed during the pre-embargo period. New commercial buildings and energy-using equipment continue to be more energy-efficient than the stock average, but these efficiency improvements are offset by an increased demand for energy services.

Over the early- and mid-2000s timeframe, a decrease in economic activity stunted growth in the stock of commercial floor space, led to negative growth in intensity of electricity use, and slowed growth in electricity sales despite continued declines in real electricity prices. The 2007–09 Great Recession, coupled with increasing real electricity prices, accelerated these trends, with the notable exception of the stock of commercial floor space. From the early- to late-2010s, real electricity prices rose, the intensity of electricity use continued to decline and commercial sector electricity use stagnated. The rise in commercial electricity prices reflected the costs electric utilities incurred to comply with stricter environmental regulations and to replace or retrofit power-generating plants. In 2020, the commercial sector was significantly impacted by COVID-19 restrictions, resulting in a sharp decline in electricity sales, followed by a moderate recovery.

Model Description

Figure 6-1 depicts the structure of the commercial end-use model. As the figure shows, CEDMS uses a disaggregated capital stock approach to forecast energy use. Energy use is viewed as a derived demand in which electricity and other fuels are inputs, along with energy using equipment and building envelopes, in the production of end-use services.

The disaggregation of energy demand is as important in modeling the commercial sector as it is for modeling the residential sector. CEDMS categorizes commercial buildings into 21 building types. It also divides energy use in each building type among 9 possible end uses, including a residual use category (labeled "miscellaneous"). 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 6-1.) CEDMS also divides buildings among vintages, i.e., the year the building was constructed, and simulates energy use for each vintage and building type.

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

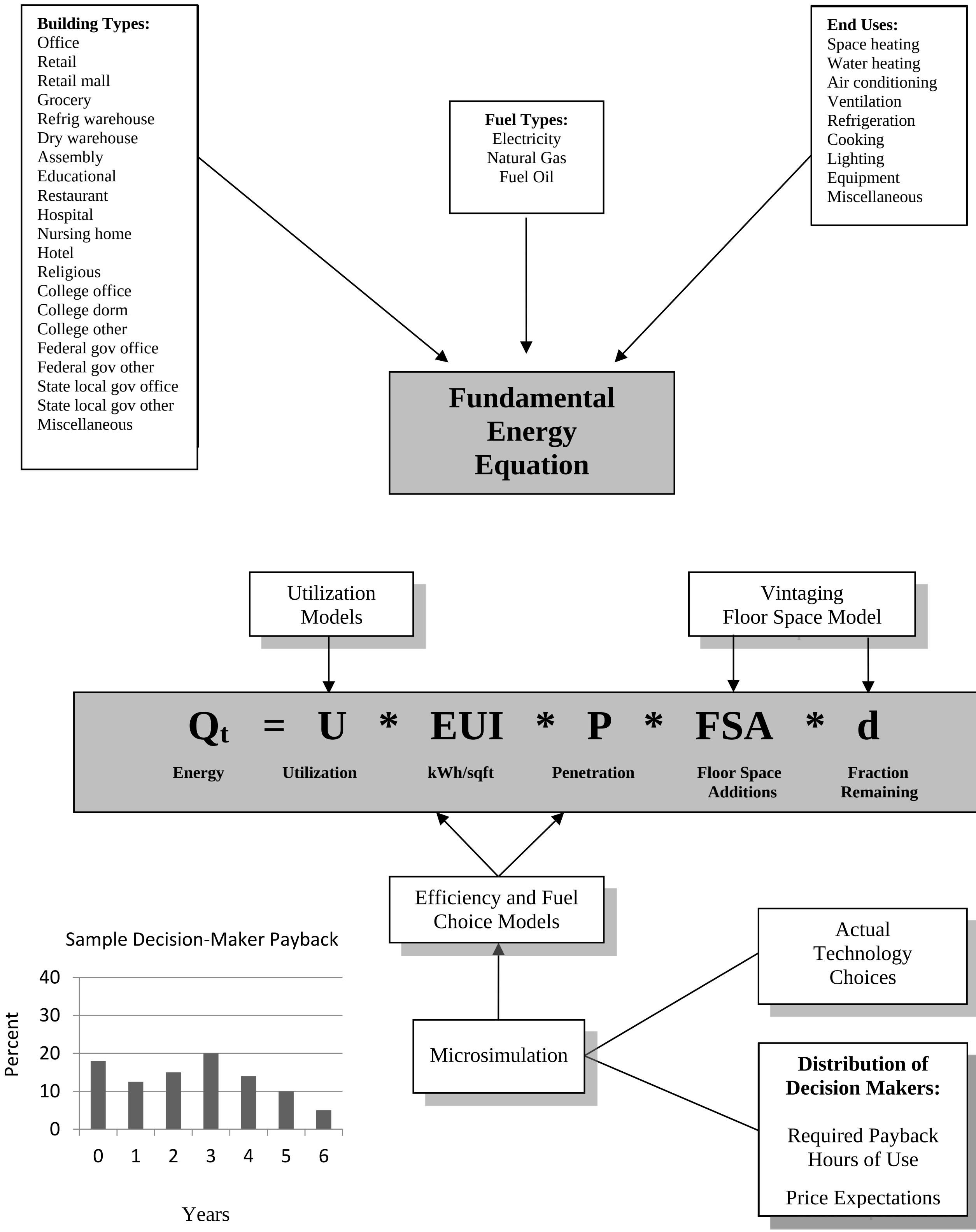
$$Q(T, i, k, l, t) = U(i, k, l, t) * e(i, k, l, t) * a(i, k, l, t) * A(l, t) * d(l, T-t)$$

where

- $*$ = multiplication operator;
- T = forecast year;
- Q = energy demand for fuel i, end use k, building type l and vintage t in the forecast year;
- t = building vintage (year);
- U = utilization, relative to some base year;
- e = energy use index, kWh/sqft/year or Btu/sqft/year;
- a = fraction of floor space served by fuel i, end use k, and building type l for floor space additions of vintage t;
- A = floor space additions by vintage t and building type l; and
- d = fraction of floor space of vintage t still standing in forecast year T.

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

Figure 6-1. Structure of Commercial End-Use Energy Modeling System



CEDMS jointly determines fuel and efficiency choices through a methodology known as discrete choice microsimulation. Essentially, sample firms in the model make choices from a set of discrete heating, ventilation and air conditioning (HVAC) equipment options. Each discrete equipment option is characterized by its fuel type, energy use, and cost. CEDMS uses the discrete technology choice methodology to model equipment choices for HVAC, water heating, refrigeration, and lighting. HVAC and lighting account for about 55 percent of total electricity use by commercial firms.

Equipment standards are easily incorporated in CEDMS' equipment choice sub-models. In addition to efficiency and fuel choices, CEDMS also models changes in equipment utilization, or intensity of use. For equipment that has not been added or replaced in the previous year, changes in equipment utilization are modeled using fuel-specific, short-run price elasticities and changes in fuel prices.

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 offset each other since the total cost of producing the end-use service is unchanged.

Table 6-1 provides the breakdown of the share of square footage of various commercial building types in the service territories of the investor-owned utilities in the first column. The second column shows the share of electricity sales for the building types. The last three columns provide projected compound annual growth rates for the square footage, electricity intensity as measured by annual sales per square foot, and growth in electricity sales.

Table 6-1. Selected Statistics for Indiana's Commercial Sector (Without DSM and EV) (Percent)

Building Type	Current Share of Square Footage	Current Share of Electricity Sales	Forecast Growth in Square Footage	Forecast Growth in Electricity Intensity	Forecast Growth in Electricity Sales
Office	15	16	0.84	-0.60	0.24
Retail	19	22	-0.44	-0.69	-1.12
Grocery	1	3	-0.44	-1.08	-1.52
Warehouse	19	8	-0.41	-0.85	-1.25
Assembly & Religious	13	9	0.43	-0.55	-0.12
Educational	10	7	1.60	-0.46	1.13
Restaurant	2	8	0.81	-1.02	-0.22
Hospital & Nursing Home	5	10	1.64	-0.96	0.66
Hotel	3	3	0.81	-0.53	0.27
College	3	3	0.24	-0.46	-0.22
Government	9	9	0.65	-0.48	0.17
Miscellaneous	1	2	0.02	-0.52	-0.50
Total	100	100	0.43	-0.60	-0.17

Summary of Results

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

Model Sensitivities

The major economic drivers to CEDMS include commercial floor space by building type (driven by non-manufacturing employment and population) and electricity prices. The sensitivity of the electricity sales projection to changes in these variables was simulated one at a time by increasing each variable ten percent above the base scenario levels and observing the change in commercial electricity use. The results are shown in Table 6-2. Changes in commercial floor space have a significant effect on electricity sales, while increases in electricity prices dampen sales.

Table 6-2. Commercial Model Long-Run Sensitivities

10 Percent Increase In	Causes This Percent Change in Electric Sales
Floor space	9.9
Electric Rates	-1.6

Indiana Commercial Electricity Sales Projections

Historical data as well as past and current projections are illustrated in Table 6-3 and Figure 6-2. As can be seen, the current base projection of Indiana commercial electricity sales growth increases annually by 0.05 percent. Historical and forecast values are provided in the Appendix of this report. As shown in Figure 6-2, the current projection lies above the 2021 forecast and below the 2023 forecast. In 2035, the current forecast begins to increase more rapidly, driven by a higher electric vehicle projection than in the previous forecast and the downward trend in commercial electricity prices. Additionally, this forecast includes significant known non-data center commercial load additions based on information provided by the utilities.

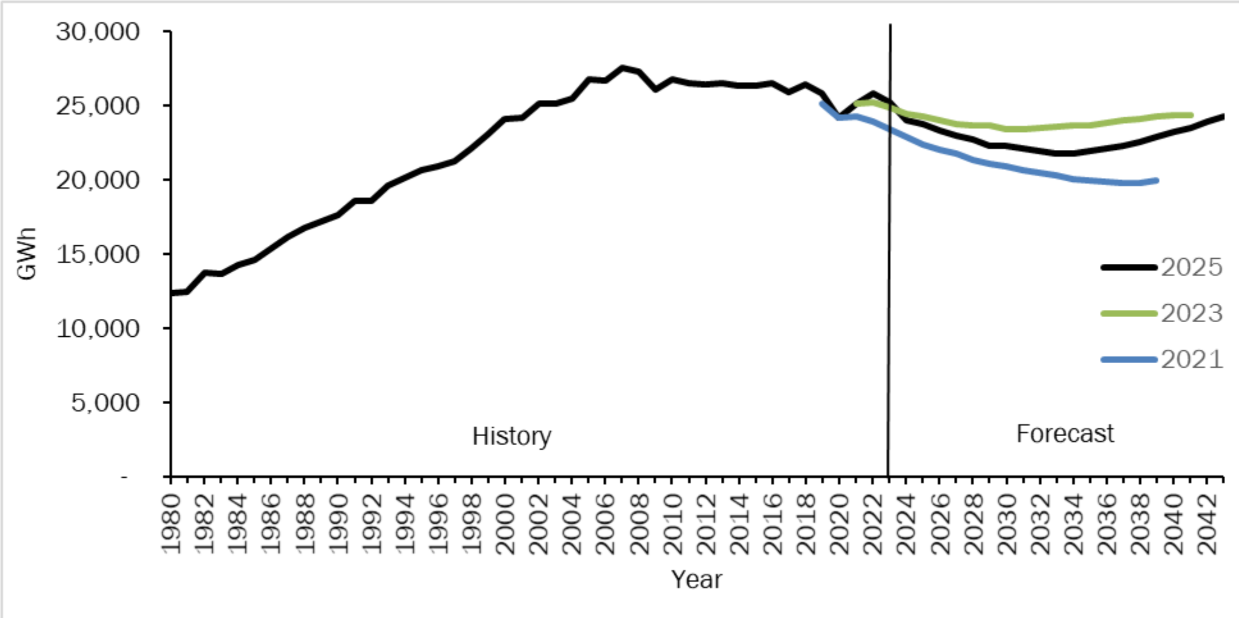
Table 6-4 summarizes SUFG's base projections of commercial electricity sales growth for the last three SUFG projections. Floor space growth and utilization are both positive in this forecast before DSM. Utilization, the amount of electricity used per unit of floor space, decreases because of increasing electricity prices, low natural gas prices, and the implementation of new efficiency standards. However, the addition of significant known non-data center commercial load additions and a higher commercial electric vehicle forecast increase sales growth enough to turn utilization positive before DSM. Incremental DSM programs have a significant effect on electricity sales significantly lowering both electricity use and sales growth. Table 6-5 shows the growth rates for the major explanatory variables.

As shown in Table 6-6 and Figure 6-3, the growth rates for the low and high scenarios are about 0.16 percent lower and 0.03 percent higher than the base scenario, respectively. These differences are primarily due to a difference in floor space growth and the number of electric vehicles.

Table 6-3. Indiana Commercial Electricity Sales Compound Annual Growth Rates (CAGR) (Percent)

Forecast	CAGR	Time Period
2025	0.05	2024-2043
2023	-0.19	2022-2041
2021	-1.02	2020-2039

Figure 6-2. Indiana Commercial Electricity Sales in GWh (Historical, Current, and Previous Forecasts)



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

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

Forecast	Electric Energy-Weighted Floor Space	Without DSM		With DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2025 SUFG Base (2024-2043)	0.53	0.17	0.70	-0.48	0.05
2023 SUFG Base (2022-2041)	0.53	-0.20	0.33	-0.72	-0.19
2021 SUFG Base (2020-2039)	0.90	-0.75	0.15	-1.92	-1.02

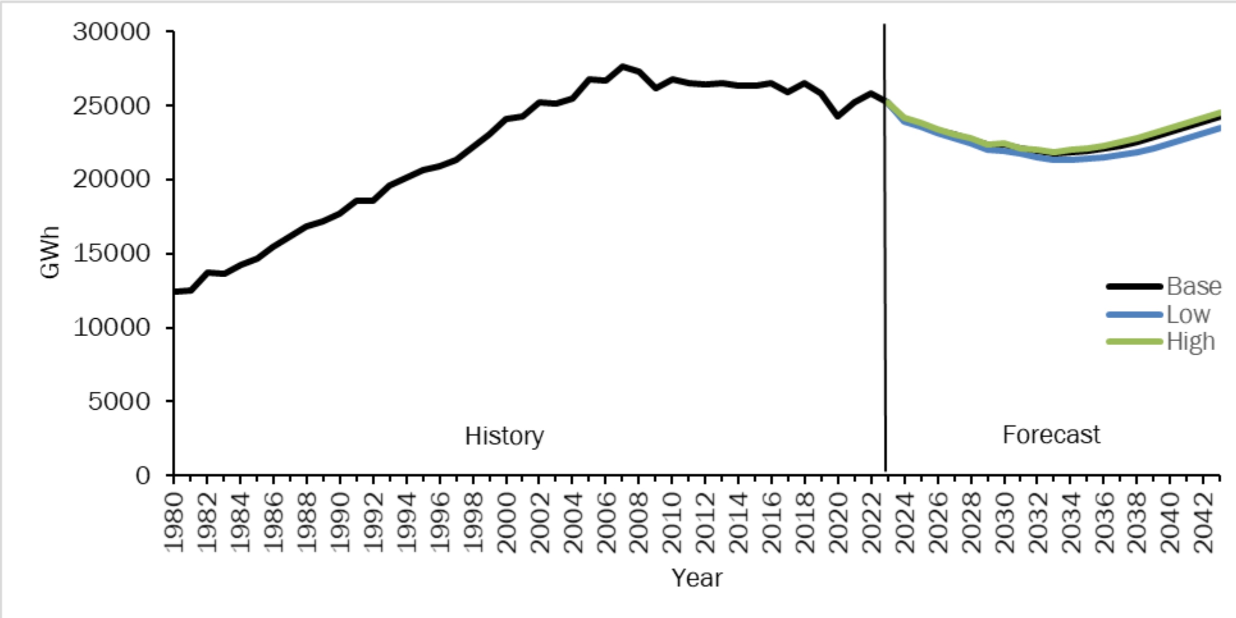
Table 6-5. Commercial Model Growth Rates (Percent) for Selected Variables (2025 SUFG Scenarios and 2023 and 2021 Base Forecasts)

Forecast	Current Scenarios (2024-2043)			2023 Forecast (2022-2041)	2021 Forecast (2020-2039)
	Base	Low	High	Base	Base
Electric Rates	1.63	1.88	1.54	0.89	1.59
Natural Gas Price	1.05	1.05	1.05	-1.06	0.81
Energy-weighted Floor Space	0.53	0.46	0.60	0.53	0.90

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

Forecast Period	Base	Low	High
2024-2043	0.05	-0.11	0.08

Figure 6-3. Indiana Commercial Electricity Sales by Scenario in GWh



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

Indiana Commercial Electricity Price Projections

Historical values and current projections of commercial electricity prices are shown in Figure 6-4, with growth rates provided in Table 6-7. The historical and forecast numbers are provided in the Appendix of this report. In real terms, commercial electricity prices declined from the mid-1980s until 2002. Real commercial electricity prices have risen since 2002 due to increases in fuel costs and installation of new emission control equipment. SUFG projects real commercial electricity prices to rise through 2033 before declining for the rest of the forecast period. SUFG's real price projections for most of the individual IOUs follow a similar pattern to the state as a whole, but there are variations across the utilities. Historical and forecast prices are included in the Appendix to this report.

Figure 6-4. Indiana Commercial Base Real Price Projections (2023 Dollars)

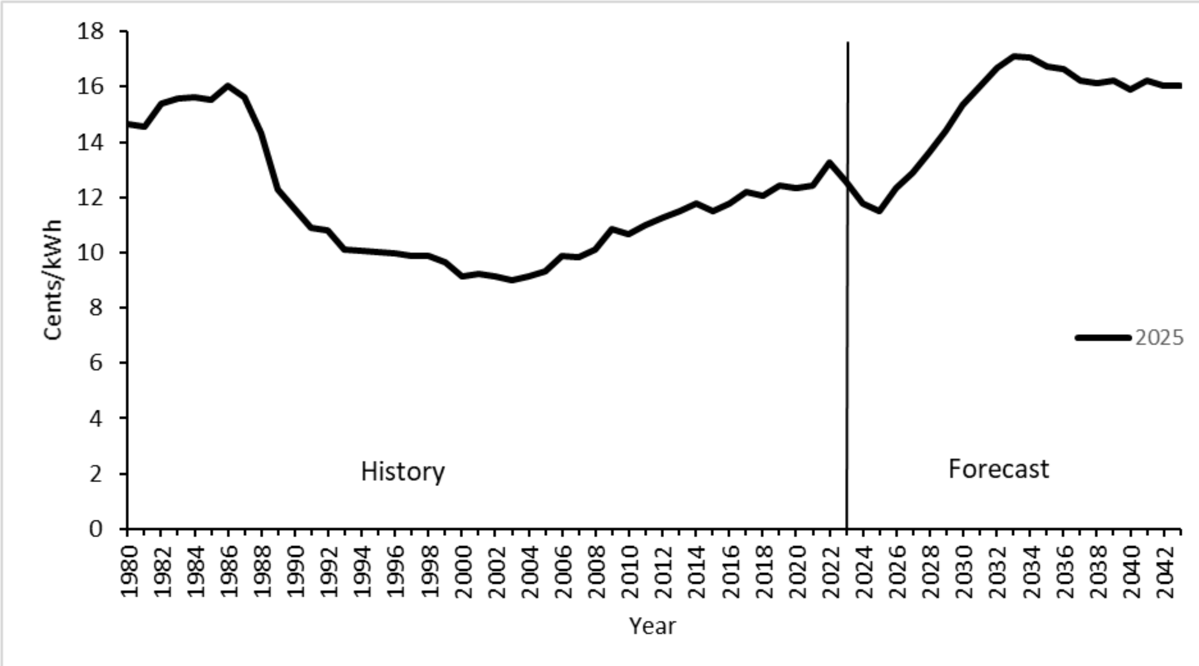


Table 6-7. Indiana Commercial Base Real Price Compound Annual Growth Rates (CAGR) (Percent)

Selected Periods	CAGR
2002-2007	1.51
2007-2012	2.74
2012-2017	1.59
2017-2022	1.68
2022-2027	-0.55
2027-2032	5.32
2032-2037	-0.56
2037-2043	-0.22
2024-2043	1.63

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

Chapter 7

Industrial Electricity Sales

Overview

SUFG has used several models to analyze and forecast electricity use in the industrial sector. The primary forecasting model is INDEED, an econometric model developed by the Electric Power Research Institute (EPRI), which is used to model the electricity use of 15 major industry groupings in the state. Additionally, SUFG has used in various forecasts a highly detailed process model of the iron and steel industry, scenario-based models of the aluminum and foundries components of the primary metals industry, and an industrial motor drive model to evaluate and forecast the effects of motor technologies and standards.

The econometric model was calibrated at the statewide level of electricity purchases using cost-share data from the U.S. Department of Commerce Annual Survey of Manufacturers. SUFG has been using INDEED since 1992 to project electricity sales for the 15 individual industries within each of the five IOU service areas. There are many econometric formulations that can be used to forecast industrial electricity use, which range from single equation factor demand models and fuel share models to “KLEM” models (KLEM denotes capital, labor, energy and materials). INDEED is a KLEM model. A KLEM model assumes that firms act as though they are minimizing costs to produce given levels of output. Thus, a KLEM model estimates the changes in the quantity of each input, which result from changes in input prices and levels of output under the cost minimization assumption. For each of the 15 industry groups, INDEED estimates the quantity consumed of eight inputs: capital, labor, electricity, natural gas, distillate and residual oil, coal, and materials.

Historical Perspective

SUFG distinguishes seven periods of distinctly different economic activity for real manufacturing product, real electric rates and electric energy sales.

During the decade prior to the OPEC oil embargo, industrial electricity sales steadily increased. In Indiana, as elsewhere, sales growth was driven by the combined economic stimuli of falling electricity prices and growing manufacturing output. During the decade following 1974, sales growth slowed as real electricity prices increased and the state’s manufacturing output declined. This turnaround in economic conditions and electricity prices resulted in a dramatic decline in the growth of industrial electricity sales. The mid-1980s to late-1990s period, experienced another dramatic turnaround. The growth rate of industrial output once again increased, and was substantially above the annual growth rate observed during the pre-embargo era. Real electricity prices in Indiana continued to decline in the industrial sector. These conditions caused electricity sales to grow moderately during this period.

The effect of the economic slowdown from late-1990s to mid-2000s was particularly pronounced in the industrial sector. During this period, real industrial electricity prices declined, but this decline was partially offset by a moderate growth in manufacturing output, resulting in stagnant growth in industrial electricity use. Between the late 2000s and early 2010s, the impacts of the 2008 economic recession caused a considerable downturn in manufacturing output growth and industrial electricity consumption, followed by a slow, long-term recovery. In the period from early-2010s to 2019 real industrial electricity prices increased, reflecting the costs incurred to comply with stricter environmental regulations and replace/retrofit ageing infrastructure. In this period, real growth in manufacturing output continued to be modest, and overall industrial electricity sales growth remained stagnant. This period was followed by a sharp decline in manufacturing output caused by the COVID-19 pandemic, accompanied by a steep reduction in industrial electricity sales.

Model Description

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

Each model is driven by projections of GSP for selected industries over the forecast horizon provided by CEMR. Each industry's share of GSP is given in the first column of Table 7-1. Seventy-five percent of state GSP is accounted for by the following industries: primary metals, 15 percent; fabricated metals, 4 percent; industrial machinery and equipment, 6 percent; chemicals, 12 percent; transportation equipment, 34 percent; and electronic and electric equipment, 4 percent.

The share of total electricity consumed by each industry is shown in the second column of Table 7-1. Both the chemicals and primary metals industries are very electric-intensive industries. Combined, they account for almost half of the total state industrial electricity use. Column four gives the current base output projections for the major industries derived from the most recent CEMR forecast. This is the eleventh SUFG forecast developed since CEMR switched from the SIC to the newer NAICS (North American Industry Classification System) for categorization of industrial economic activity. Generally, the NAICS is more detailed than the SIC system. Since SUFG uses the SIC system, SUFG maps industrial economic activity projections from the NAICS measures used by CEMR to the older SIC measures used in SUFG's models. This process is relatively straightforward with the exception of SIC 28, chemical manufacturing. In SIC 28, chemical manufacturing, SUFG used the CEMR GSP growth projections for the other non-durable manufacturing sector. This was necessary because CEMR's projections did not specifically include chemicals manufacturing, a large purchaser of electricity in Indiana.

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

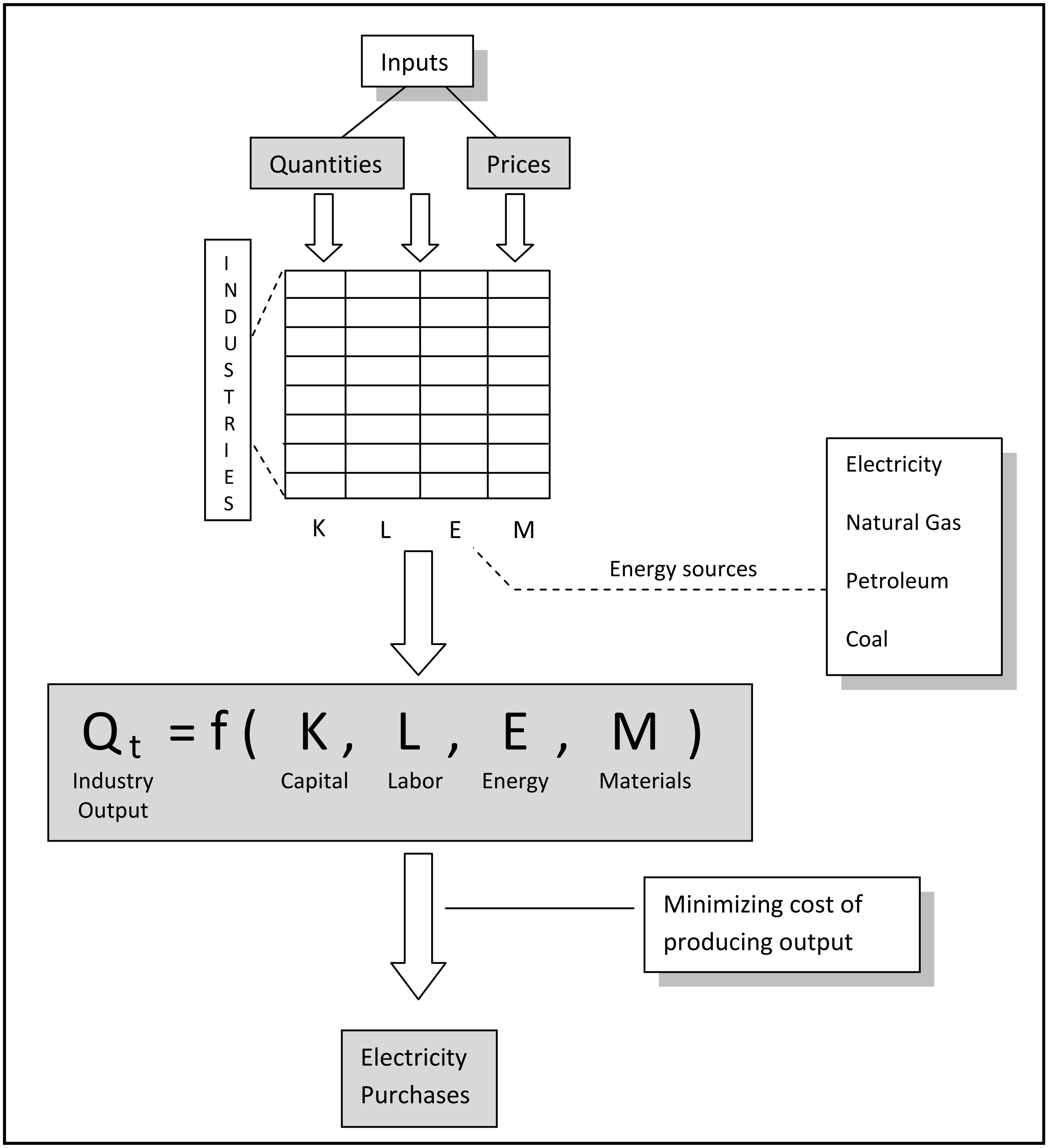
As described earlier in this chapter, INDEED captures the competition between the various inputs for their share of the cost of production by assuming firms seek the mix of inputs that minimizes the production cost for a given level of output. Unit costs of natural gas, oil, coal, capital, labor and materials are inputs to the SUFG system, while the cost per kWh of electricity is determined by the SUFG modeling system. For fuel prices, SUFG uses the current EIA forecast, which assumes that real natural gas prices will increase gradually through 2035, before slowly decreasing and then remaining flat over the last six years of the forecast horizon. Distillate prices are projected to decrease gradually until 2030, followed by a modest increase for the rest of the forecast period. Unit costs for capital, labor and materials are consistent with the assumptions contained in the CEMR forecast of Indiana output growth. The changes in electricity intensities, expressed as a percent change in kWh per dollar of GSP, are shown in column five of Table 7-1.

The last column of Table 7-1 contains the projected annual percent increase in electricity sales by major industry. This projected increase is the sum of changes in GSP and kWh/GSP for each industry. Average industrial electricity use across all sectors in the base scenario is expected to increase at an average of 0.86 percent per year, without DSM, over the forecast horizon.

Table 7-1. Selected Statistics for Indiana's Industrial Sector (Without DSM) (Percent)

SIC	Name	Current Share of GSP	Current Share of Electricity Sales	Current Intensity	Forecast Growth in GSP Originating by Sector	Forecast Growth in Electricity Intensity by Sector	Forecast Growth in Electricity Sales by Sector
20	Food & Kindred Products	3.51	4.82	0.36	1.75	-1.91	-0.16
21	Tobacco Products	0.001	0.00	0.02	1.75	-1.75	0.001
22	Textile Mill Products	0.06	0.10	0.40	1.75	-2.91	-1.15
23	Apparel & Other Textile Products	0.41	0.09	0.06	1.75	-1.21	0.54
24	Lumber & Wood Products	1.95	0.76	0.10	1.75	-0.63	1.12
25	Furniture & Fixtures	2.41	0.53	0.06	1.61	-1.46	0.15
26	Paper & Allied Products	1.36	3.97	0.76	1.75	-1.00	0.75
27	Printing & Publishing	2.55	0.81	0.08	1.75	-2.40	-0.65
28	Chemicals & Allied Products	12.18	20.30	0.43	1.75	-2.37	-0.62
29	Petroleum & Coal Products	3.51	6.33	0.47	1.75	0.00	1.75
30	Rubber & Misc. Plastic Products	2.13	6.06	0.74	1.54	-1.13	0.42
31	Leather & Leather Products	0.07	0.01	0.04	1.61	-2.75	-1.14
32	Stone, Clay, & Glass Products	2.44	5.60	0.60	1.61	-1.00	0.61
33	Primary Metal Products	14.69	28.66	0.51	-0.07	0.32	0.26
34	Fabricated Metal Products	3.68	4.44	0.31	-0.09	-1.43	-1.51
35	Industrial Machinery & Equipment	5.96	4.53	0.20	0.69	-1.39	-0.71
36	Electronic & Electric Equipment	3.73	1.79	0.12	-0.17	-0.89	-1.06
37	Transportation Equipment	34.32	8.57	0.06	3.20	-1.14	2.05
38	Instruments & Related Products	3.27	1.38	0.11	1.61	-1.57	0.04
39	Miscellaneous Manufacturing	1.77	1.24	0.18	1.61	-3.43	-1.81
Total	Manufacturing	100.00	100.00	0.26	1.89	-1.03	0.86

Figure 7-1. Structure of Industrial Energy Modeling System



Summary of Results

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

Model Sensitivities

Table 7-2 shows the impact of a 10 percent increase in each of the model inputs on all industrial electricity consumption in the econometric model. Electricity sales (GWh) are most sensitive to changes in output and electric rates, somewhat sensitive to changes in gas and oil prices, and insensitive to changes in assumed coal prices. Other variables affecting industrial electricity use include the prices of materials, capital, labor, and automation. Furthermore, changes in tariffs may affect the manufacturing sector, resulting in direct implications for industrial electricity consumption. The overall economic impact remains uncertain as these developments continue to evolve. The sensitivities of the model's key variables were determined by increasing each variable ten percent above the base scenario levels and observing the percent change in forecast industrial electricity use after 10 years.

Table 7-2. Industrial Model Long-Run Sensitivities

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

Indiana Industrial Electricity Sales Projections

Past and current projections for industrial energy sales as well as overall annual average growth rates for the current and past forecasts are shown in Table 7-3 and Figure 7-2. Historical and forecast values are provided in the Appendix of this report.

The impact of industrial sector DSM programs on growth rates for the 2021, 2023, and current forecasts is displayed in Table 7-4. The table also disaggregates the impact on energy growth of output, changes in the mix of output and electricity intensity. Industrial sector DSM programs are expected to have a small impact on retail sales, due in part to industrial customers having the ability to opt out. The effect of earlier conservation activities is embedded in the historical data and SUFG's projections. Additionally, this forecast includes significant known non-data center industrial load additions based on information provided by the utilities.

The current forecast projects that industrial sector electricity sales will grow from the 2024 level of approximately 35,200 GWh to about 41,400 GWh by 2043. This growth rate of 0.85 percent per year is higher than the 0.05 percent rate projected for the commercial sector and lower than the 1.81 percent rate projected for the residential sector. As shown in Figure 7-3, the current forecast is relatively flat through 2034, then increases through the remainder of the forecast horizon. The late increase is driven by projected decreases in electricity prices in those years.

The growth in industrial electricity sales is impacted by two counterbalancing factors: manufacturing output and electricity intensity (electricity usage per dollar of output). Compared to the previous forecast, the projected growth in manufacturing output is higher (1.89 percent per year vs. 1.24 percent) and the electricity intensity is lower (-0.66 percent per year vs. -0.40 percent). Thus, the change in manufacturing output is outweighing the change in intensity, resulting in more robust growth in the industrial sales in this forecast than in previous ones. However, due to a lower starting value in this forecast, the industrial electricity sales are lower than in the previous forecast over most of the forecast horizon.

Table 7-5 and Figure 7-3 show how industrial electricity sales differ by scenario. Industrial sales, in the high scenario, are expected to increase to 45,654 GWh by 2043, 10.29 percent higher than the base projection. In the low scenario, industrial sales grow more slowly, which results in 37,262 GWh sales by 2043, 9.99 percent below the base scenario.

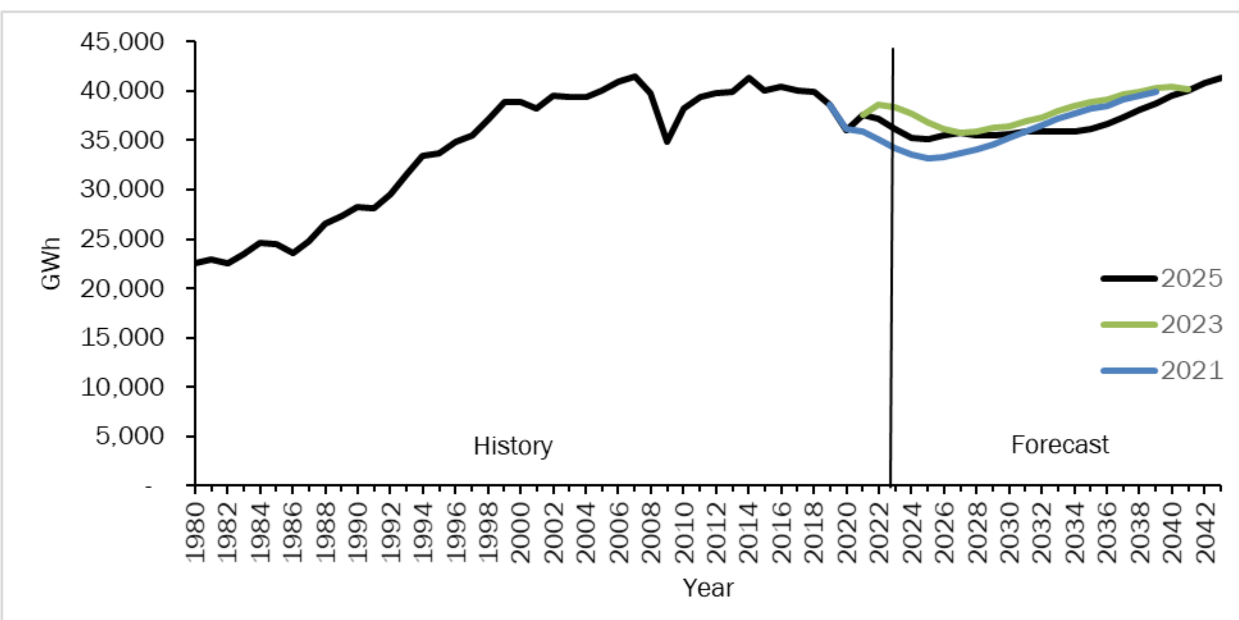
The wide range of forecast sales is caused primarily by the equally wide range of the trajectories of industrial output contained in the CEMR low and high scenarios for the state. In the base scenario, GSP in the industrial sector grows 1.89 percent per year during the forecast period. That rate is 2.68 percent in the high scenario and 1.12 percent in the low scenario. This reflects the uncertainty regarding Indiana's industrial future contained in these forecasts.

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

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

Forecast	CAGR	Time Period
2025	0.85	2024-2043
2023	0.20	2022-2041
2021	0.53	2020-2039

Figure 7-2. Indiana Industrial Electricity Sales in GWh (Historical, Current, and Previous Forecasts)



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

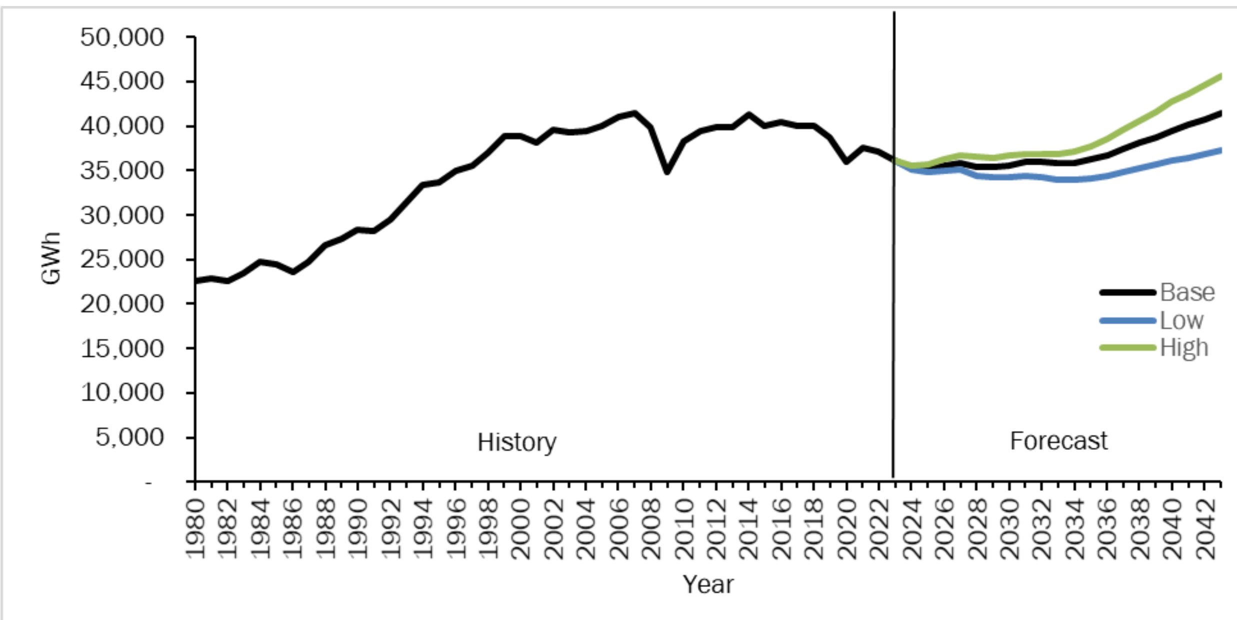
Table 7-4. History of SUFG Industrial Sector Growth Rates (Percent)

Forecast	Output	Mix Effects	Electric Energy-Weighted Output	Without DSM		With DSM	
				Intensity	Sales Growth	Intensity	Sales Growth
2025 SUFG Base (2024-2043)	1.89	-0.36	1.53	-0.66	0.86	-0.68	0.85
2023 SUFG Base (2022-2041)	1.24	-0.59	0.65	-0.40	0.25	-0.45	0.20
2021 SUFG Base (2020-2039)	1.31	-0.70	0.61	-0.08	0.53	-0.08	0.53

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

Forecast Period	Base	Low	High
2024-2043	0.85	0.32	1.32

Figure 7-3. Indiana Industrial Electricity Sales by Scenario in GWh



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

Indiana Industrial Electricity Price Projections

Historical values and current projections of industrial electricity prices are shown in Table 7-6 and Figure 7-4. In real terms, industrial electricity prices declined from the mid-1980s until 2002. Real industrial electricity prices have risen since 2002 due to increases in fuel costs and the installation of new emissions control equipment. SUFG projects real industrial electricity prices to rise through 2034 before declining for the rest of the forecast period. SUFG's real price projections for the individual IOUs follow the same patterns as the state as a whole, but there are variations across the utilities. Historical and forecast prices are included in the Appendix of this report.

Figure 7-4. Indiana Industrial Base Real Price Projections (2023 Dollars)

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

Selected Periods	CAGR
2002-2007	1.37
2007-2012	3.48
2012-2017	1.73
2017-2022	0.70
2022-2027	0.41
2027-2032	4.45
2032-2037	-0.05
2037-2043	-0.32
2024-2043	2.11

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

Appendix

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

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

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

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

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

Indiana Michigan Power Company (I&M), Wabash Valley Power Alliance (WVPA), Indiana Municipal Power Agency (IMPA), and Hoosier Energy serve load outside of the state which SUFG excluded in developing projections for Indiana. I&M's load is split approximately 85-15 percent between Indiana and Michigan. While the majority of WVPA's load is in Indiana, 74 percent, it does have members in Illinois and Missouri. IMPA has a wholesale member in Ohio, although approximately 99 percent of its load is in Indiana. Hoosier Energy serves members in Indiana and Illinois. Approximately 95 percent of Hoosier's load is currently in Indiana. These utilities have provided SUFG with data pertaining to their Indiana load.

Some Indiana utilities report sales to the commercial and industrial sectors (SUFG's classification) as sales to one aggregate classification or sales to small and large customers. In order to obtain commercial and industrial sales for these utilities, SUFG has requested data in these classifications directly from the utilities, developed approximation schemes to disaggregate the sales data, or combined more than one source of data to develop commercial and industrial sales estimates.

SUFG does not have sectoral level sales data for all of the unaffiliated rural electric membership cooperatives (REMCs) and unaffiliated municipalities. SUFG obtains the data that is available from the Energy Information Administration (EIA) and FERC in order to construct a total starting value which is then grown at the rate of IMPA in the case of the unaffiliated municipalities and WVPA in the case of the unaffiliated REMCs. SUFG then allocates the unaffiliated municipalities and REMCs sales to residential, commercial, industrial and other sales with an allowance for losses based on the sector allocations of IMPA and WVPA, respectively.

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 eight entities that SUFG models, plus an estimate of sales and losses for unaffiliated municipalities and cooperatives. Sales-for-resale are excluded from the state aggregate total energy requirements to avoid double counting.

Summer peak demand estimates are based on a combination of FERC Form 1 data and company sources.

Statewide summer peak demand may not be obtained by simply adding across utilities because of diversity. Diversity refers to the fact that all Indiana utilities do not experience their summer peak demand at the same instant. Due to differences in weather, sectoral mix, end-use saturation, etc., the utilities tend to face their individual summer peak demands at different hours, days, or even months. To obtain an estimate of statewide peak demand, the summer peak demand estimates for the individual utilities are added together and adjusted for diversity.

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

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

SUFG 2025 Base Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales						Energy	Summer
		Res	Com	Ind	Other	Total	Losses	Required	Demand
Hist	2002	32,168	25,195	39,580	534	97,478	7,182	104,660	18,831
Hist	2003	30,912	25,131	39,355	584	95,982	7,052	103,034	18,794
Hist	2004	31,005	25,482	39,458	638	96,582	7,083	103,665	18,193
Hist	2005	33,654	26,787	39,988	612	101,042	7,406	108,447	19,944
Hist	2006	32,488	26,711	41,006	596	100,801	7,382	108,182	20,855
Hist	2007	34,972	27,611	41,477	638	104,698	7,671	112,369	20,858
Hist	2008	34,099	27,274	39,800	625	101,798	7,463	109,260	19,275
Hist	2009	32,611	26,127	34,867	631	94,236	6,921	101,157	19,054
Hist	2010	35,119	26,800	38,271	662	100,852	7,396	108,248	20,315
Hist	2011	33,994	26,551	39,440	640	100,625	7,378	108,003	21,729
Hist	2012	33,077	26,452	39,842	597	99,968	7,330	107,298	21,048
Hist	2013	33,596	26,517	39,930	602	100,644	7,373	108,017	20,423
Hist	2014	33,843	26,360	41,350	614	102,167	7,468	109,635	20,111
Hist	2015	32,573	26,346	40,002	592	99,513	7,289	106,802	19,013
Hist	2016	33,230	26,546	40,463	598	100,837	7,396	108,233	18,872
Hist	2017	31,773	25,909	40,025	595	98,301	7,215	105,516	18,076
Hist	2018	34,633	26,478	39,980	595	101,686	7,280	108,966	19,367
Hist	2019	33,559	25,832	38,649	567	98,607	7,012	105,619	19,012
Hist	2020	33,062	24,237	35,986	528	93,814	6,379	100,193	18,323
Hist	2021	33,536	25,179	37,607	525	96,847	6,544	103,392	19,524
Hist	2022	34,082	25,814	37,193	510	97,599	6,380	103,979	19,250
Hist	2023	31,988	25,212	36,113	494	93,806	6,142	99,949	19,789
Frcst	2024	33,244	24,045	35,232	494	93,015	6,127	99,142	19,720
Frcst	2025	33,342	23,785	35,177	497	92,801	6,113	98,913	19,666
Frcst	2026	33,584	23,351	35,476	502	92,913	6,139	99,052	19,379
Frcst	2027	33,945	23,015	35,796	505	93,261	6,178	99,440	19,639
Frcst	2028	34,243	22,719	35,449	508	92,919	6,163	99,082	19,546
Frcst	2029	34,574	22,349	35,447	510	92,880	6,173	99,053	19,493
Frcst	2030	34,925	22,342	35,599	512	93,378	6,193	99,571	19,502
Frcst	2031	35,460	22,127	35,936	514	94,037	6,250	100,287	19,597
Frcst	2032	36,051	21,949	35,943	516	94,459	6,288	100,746	19,353
Frcst	2033	36,759	21,785	35,848	518	94,909	6,320	101,229	19,419
Frcst	2034	37,651	21,827	35,905	519	95,902	6,389	102,291	19,285
Frcst	2035	38,630	21,937	36,216	521	97,304	6,483	103,787	19,485
Frcst	2036	39,688	22,116	36,713	524	99,040	6,600	105,641	19,884
Frcst	2037	40,667	22,312	37,380	526	100,884	6,724	107,608	19,957
Frcst	2038	41,689	22,560	38,085	528	102,862	6,855	109,717	20,414
Frcst	2039	42,731	22,870	38,771	530	104,902	6,989	111,892	20,956
Frcst	2040	43,780	23,216	39,490	532	107,018	7,128	114,146	21,150
Frcst	2041	44,738	23,532	40,097	534	108,900	7,254	116,154	21,683
Frcst	2042	45,779	23,913	40,769	535	110,997	7,392	118,388	22,068
Frcst	2043	46,770	24,268	41,395	537	112,970	7,524	120,494	22,155

Compound Annual Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
2002-2007	1.69	1.85	0.94	3.63	1.44	1.33	1.43	2.07
2007-2012	-1.11	-0.85	-0.80	-1.32	-0.92	-0.91	-0.92	0.18
2012-2017	-0.80	-0.41	0.09	-0.08	-0.34	-0.32	-0.33	-3.00
2017-2022	1.41	-0.07	-1.46	-3.03	-0.14	-2.43	-0.29	1.27
2022-2027	-0.08	-2.27	-0.76	-0.21	-0.91	-0.64	-0.89	0.40
2027-2032	1.21	-0.94	0.08	0.44	0.26	0.35	0.26	-0.29
2032-2037	2.44	0.33	0.79	0.38	1.32	1.35	1.33	0.62
2037-2043	2.36	1.41	1.72	0.34	1.90	1.89	1.90	1.76
2024-2043	1.81	0.05	0.85	0.44	1.03	1.09	1.03	0.61

SUFG 2025 Low Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
Hist	2002	32,168	25,195	39,580	534	97,478	7,182	104,660	18,831
Hist	2003	30,912	25,131	39,355	584	95,982	7,052	103,034	18,794
Hist	2004	31,005	25,482	39,458	638	96,582	7,083	103,665	18,193
Hist	2005	33,654	26,787	39,988	612	101,042	7,406	108,447	19,944
Hist	2006	32,488	26,711	41,006	596	100,801	7,382	108,182	20,855
Hist	2007	34,972	27,611	41,477	638	104,698	7,671	112,369	20,858
Hist	2008	34,099	27,274	39,800	625	101,798	7,463	109,260	19,275
Hist	2009	32,611	26,127	34,867	631	94,236	6,921	101,157	19,054
Hist	2010	35,119	26,800	38,271	662	100,852	7,396	108,248	20,315
Hist	2011	33,994	26,551	39,440	640	100,625	7,378	108,003	21,729
Hist	2012	33,077	26,452	39,842	597	99,968	7,330	107,298	21,048
Hist	2013	33,596	26,517	39,930	602	100,644	7,373	108,017	20,423
Hist	2014	33,843	26,360	41,350	614	102,167	7,468	109,635	20,111
Hist	2015	32,573	26,346	40,002	592	99,513	7,289	106,802	19,013
Hist	2016	33,230	26,546	40,463	598	100,837	7,396	108,233	18,872
Hist	2017	31,773	25,909	40,025	595	98,301	7,215	105,516	18,076
Hist	2018	34,633	26,478	39,980	595	101,686	7,280	108,966	19,367
Hist	2019	33,559	25,832	38,649	567	98,607	7,012	105,619	19,012
Hist	2020	33,062	24,237	35,986	528	93,814	6,379	100,193	18,323
Hist	2021	33,536	25,179	37,607	525	96,847	6,544	103,392	19,524
Hist	2022	34,082	25,814	37,193	510	97,599	6,380	103,979	19,250
Hist	2023	31,988	25,212	36,113	494	93,806	6,142	99,949	19,789
Frcst	2024	33,141	23,945	35,078	492	92,656	6,101	98,757	19,718
Frcst	2025	33,105	23,590	34,805	495	91,995	6,056	98,051	19,578
Frcst	2026	33,301	23,148	34,925	499	91,874	6,067	97,941	19,255
Frcst	2027	33,572	22,777	35,043	502	91,894	6,084	97,977	19,458
Frcst	2028	33,748	22,411	34,461	505	91,125	6,041	97,166	19,288
Frcst	2029	33,992	22,005	34,256	507	90,760	6,030	96,790	19,181
Frcst	2030	34,275	21,973	34,205	508	90,961	6,031	96,991	19,133
Frcst	2031	34,699	21,721	34,385	509	91,313	6,067	97,380	19,180
Frcst	2032	35,219	21,535	34,277	510	91,541	6,091	97,632	18,911
Frcst	2033	35,767	21,299	34,012	512	91,590	6,097	97,688	18,899
Frcst	2034	36,596	21,336	33,990	515	92,438	6,158	98,596	18,776
Frcst	2035	37,454	21,396	34,115	516	93,481	6,228	99,709	18,919
Frcst	2036	38,375	21,511	34,370	518	94,774	6,316	101,090	19,213
Frcst	2037	39,258	21,665	34,787	520	96,230	6,414	102,644	19,226
Frcst	2038	40,211	21,888	35,265	521	97,886	6,524	104,409	19,629
Frcst	2039	41,134	22,140	35,686	523	99,483	6,630	106,113	20,072
Frcst	2040	42,138	22,468	36,134	525	101,265	6,747	108,012	20,207
Frcst	2041	43,050	22,755	36,470	527	102,802	6,850	109,652	20,677
Frcst	2042	44,090	23,147	36,881	529	104,646	6,971	111,617	21,022
Frcst	2043	44,998	23,445	37,262	531	106,236	7,083	113,319	21,043

Compound Annual Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
2002-2007	1.69	1.85	0.94	3.63	1.44	1.33	1.43	2.07
2007-2012	-1.11	-0.85	-0.80	-1.32	-0.92	-0.91	-0.92	0.18
2012-2017	-0.80	-0.41	0.09	-0.08	-0.34	-0.32	-0.33	-3.00
2017-2022	1.41	-0.07	-1.46	-3.03	-0.14	-2.43	-0.29	1.27
2022-2027	-0.30	-2.47	-1.18	-0.32	-1.20	-0.95	-1.18	0.22
2027-2032	0.96	-1.12	-0.44	0.33	-0.08	0.02	-0.07	-0.57
2032-2037	2.20	0.12	0.30	0.35	1.00	1.04	1.01	0.33
2037-2043	2.30	1.32	1.15	0.36	1.66	1.67	1.66	1.52
2024-2043	1.62	-0.11	0.32	0.40	0.72	0.79	0.73	0.34

SUFG 2025 High Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales						Energy	Summer
		Res	Com	Ind	Other	Total	Losses	Required	Demand
Hist	2002	32,168	25,195	39,580	534	97,478	7,182	104,660	18,831
Hist	2003	30,912	25,131	39,355	584	95,982	7,052	103,034	18,794
Hist	2004	31,005	25,482	39,458	638	96,582	7,083	103,665	18,193
Hist	2005	33,654	26,787	39,988	612	101,042	7,406	108,447	19,944
Hist	2006	32,488	26,711	41,006	596	100,801	7,382	108,182	20,855
Hist	2007	34,972	27,611	41,477	638	104,698	7,671	112,369	20,858
Hist	2008	34,099	27,274	39,800	625	101,798	7,463	109,260	19,275
Hist	2009	32,611	26,127	34,867	631	94,236	6,921	101,157	19,054
Hist	2010	35,119	26,800	38,271	662	100,852	7,396	108,248	20,315
Hist	2011	33,994	26,551	39,440	640	100,625	7,378	108,003	21,729
Hist	2012	33,077	26,452	39,842	597	99,968	7,330	107,298	21,048
Hist	2013	33,596	26,517	39,930	602	100,644	7,373	108,017	20,423
Hist	2014	33,843	26,360	41,350	614	102,167	7,468	109,635	20,111
Hist	2015	32,573	26,346	40,002	592	99,513	7,289	106,802	19,013
Hist	2016	33,230	26,546	40,463	598	100,837	7,396	108,233	18,872
Hist	2017	31,773	25,909	40,025	595	98,301	7,215	105,516	18,076
Hist	2018	34,633	26,478	39,980	595	101,686	7,280	108,966	19,367
Hist	2019	33,559	25,832	38,649	567	98,607	7,012	105,619	19,012
Hist	2020	33,062	24,237	35,986	528	93,814	6,379	100,193	18,323
Hist	2021	33,536	25,179	37,607	525	96,847	6,544	103,392	19,524
Hist	2022	34,082	25,814	37,193	510	97,599	6,380	103,979	19,250
Hist	2023	31,988	25,212	36,113	494	93,806	6,142	99,949	19,789
Frcst	2024	33,358	24,160	35,609	495	93,622	6,169	99,791	19,723
Frcst	2025	33,392	23,803	35,709	499	93,402	6,154	99,557	19,655
Frcst	2026	33,706	23,420	36,209	504	93,838	6,203	100,041	19,432
Frcst	2027	34,082	23,085	36,666	507	94,341	6,251	100,592	19,717
Frcst	2028	34,417	22,816	36,490	510	94,233	6,251	100,484	19,660
Frcst	2029	34,702	22,378	36,413	513	94,006	6,252	100,258	19,558
Frcst	2030	35,159	22,453	36,631	514	94,758	6,288	101,046	19,621
Frcst	2031	35,565	22,137	36,856	515	95,074	6,323	101,396	19,636
Frcst	2032	36,243	21,989	36,832	517	95,582	6,366	101,948	19,386
Frcst	2033	37,034	21,877	36,799	518	96,228	6,412	102,640	19,478
Frcst	2034	38,058	21,992	37,133	519	97,702	6,511	104,213	19,410
Frcst	2035	39,091	22,127	37,747	520	99,486	6,629	106,115	19,667
Frcst	2036	40,174	22,317	38,538	522	101,551	6,767	108,319	20,157
Frcst	2037	41,201	22,546	39,546	525	103,817	6,917	110,734	20,302
Frcst	2038	42,285	22,837	40,650	527	106,299	7,080	113,379	20,826
Frcst	2039	43,303	23,111	41,652	529	108,596	7,232	115,827	21,425
Frcst	2040	44,413	23,495	42,716	531	111,155	7,399	118,553	21,703
Frcst	2041	45,288	23,809	43,638	533	113,269	7,537	120,806	22,279
Frcst	2042	46,263	24,199	44,634	536	115,632	7,691	123,323	22,717
Frcst	2043	47,161	24,553	45,654	538	117,905	7,843	125,749	22,856

Compound Annual Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
2002-2007	1.69	1.85	0.94	3.63	1.44	1.33	1.43	2.07
2007-2012	-1.11	-0.85	-0.80	-1.32	-0.92	-0.91	-0.92	0.18
2012-2017	-0.80	-0.41	0.09	-0.08	-0.34	-0.32	-0.33	-3.00
2017-2022	1.41	-0.07	-1.46	-3.03	-0.14	-2.43	-0.29	1.27
2022-2027	0.00	-2.21	-0.28	-0.12	-0.68	-0.41	-0.66	0.48
2027-2032	1.24	-0.97	0.09	0.39	0.26	0.37	0.27	-0.34
2032-2037	2.60	0.50	1.43	0.29	1.67	1.67	1.67	0.93
2037-2043	2.28	1.43	2.42	0.42	2.14	2.12	2.14	1.99
2024-2043	1.84	0.08	1.32	0.44	1.22	1.27	1.22	0.78

Indiana Base Average Retail Rates (Cents/kWh) (in 2023 Dollars)

Year	Res	Com	Ind	Average
2002	10.85	9.13	6.43	8.46
2003	10.82	9.01	6.33	8.36
2004	10.89	9.15	6.43	8.47
2005	10.90	9.32	6.60	8.66
2006	11.69	9.87	7.23	9.26
2007	11.23	9.85	6.88	9.02
2008	11.68	10.10	7.35	9.45
2009	12.42	10.84	8.03	10.24
2010	12.17	10.68	7.85	10.03
2011	12.61	10.97	8.08	10.28
2012	12.95	11.27	8.17	10.48
2013	13.41	11.48	8.71	10.94
2014	13.84	11.77	8.97	11.23
2015	13.81	11.50	8.68	11.02
2016	13.36	11.76	8.66	11.00
2017	14.56	12.19	8.90	11.52
2018	14.31	12.06	8.71	11.43
2019	14.77	12.42	8.89	11.74
2020	14.83	12.32	8.10	11.50
2021	15.19	12.44	8.23	11.67
2022	15.82	13.25	9.21	12.54
2023	15.26	12.56	7.98	11.64
2024	14.53	11.79	7.70	11.10
2025	14.70	11.52	8.41	11.38
2026	15.72	12.35	9.05	12.19
2027	16.46	12.89	9.40	12.72
2028	17.39	13.62	9.87	13.44
2029	18.40	14.41	10.31	14.18
2030	19.57	15.34	10.90	15.06
2031	20.41	16.05	11.32	15.70
2032	21.21	16.70	11.69	16.32
2033	21.64	17.11	12.19	16.82
2034	21.57	17.07	12.25	16.85
2035	21.17	16.72	12.06	16.58
2036	21.06	16.64	11.97	16.50
2037	20.60	16.24	11.66	16.12
2038	20.44	16.13	11.58	16.01
2039	20.48	16.21	11.67	16.09
2040	20.22	15.92	11.49	15.86
2041	20.52	16.23	11.66	16.12
2042	20.24	16.02	11.53	15.92
2043	20.18	16.03	11.44	15.88
Compound Annual Growth Rates (%)				
Year-Year	Res	Com	Ind	Average
2002-2007	0.69	1.51	1.37	1.30
2007-2012	2.89	2.74	3.48	3.03
2012-2017	2.38	1.59	1.73	1.92
2017-2022	1.66	1.68	0.70	1.71
2022-2027	0.80	-0.55	0.41	0.29
2027-2032	5.20	5.32	4.45	5.12
2032-2037	-0.58	-0.56	-0.05	-0.25
2037-2043	-0.34	-0.22	-0.32	-0.25
2024-2043	1.75	1.63	2.11	1.90

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

List of Acronyms

AEO	U.S. Energy Information Administration Annual Energy Outlook
AI	Artificial intelligence
BESS	Battery Energy Storage System
BMV	Indiana Bureau of Motor Vehicles
Btu	British thermal unit
CAGR	Compound Annual Growth Rates
CC	Combined Cycle
CEDMS	Commercial Energy Demand Modeling System
CEMR	Center for Econometric Model Research
CT	Combustion Turbine
DLOL	Direct Loss of Load
DR	Demand Response
DSM	Demand-Side Management
EE	Energy Efficiency
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
EV	Electric Vehicle
EVI-Pro	U.S. Department of Energy Electric Vehicle Infrastructure Projection Tool
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GSP	Gross State Product
GWh	Gigawatt-hour
HVAC	Heating, Ventilation and Air Conditioning
I&M	Indiana Michigan Power Company
IBRC	Indiana Business Research Center
IMPA	Indiana Municipal Power Agency
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
IURC	Indiana Utility Regulatory Commission
IVFD	Indiana Vehicle Fuel Dashboard
KLEM	Capital, labor, energy, and materials
kWh	Kilowatt-hour
LPG	Liquefied Petroleum Gas
mmBtu	million British thermal units
MISO	Midcontinent Independent System Operator
MW	Megawatt
NAICS	North American Industry Classification System
NFP	Not-for-Profit
NLR	National Laboratory of the Rockies
NPV	Net present value
NREL	National Renewable Energy Laboratory
OPEC	Organization of Petroleum Exporting Countries
ORNL	Oak Ridge National Labs
PJM	PJM Interconnection LLC
PPA	Purchase Power Agreement
REDMS	Residential Energy Demand Modeling System
REEMS	Residential End-Use Energy Modeling System

RTO	Regional Transmission Organization
RUS	U.S. Department of Agriculture Rural Utilities Service
SIC	Standard Industrial Classification
sqft	square feet
SMR	Small modular reactor
SUFG	State Utility Forecasting Group
TWh	Terawatt-hour
WVPA	Wabash Valley Power Alliance