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Hoosier Energy
2017 Integrated Resource Plan – Public Version
Volume I: Main Report

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Prepared By:

Hoosier Energy Rural Electric Cooperative, Inc.
P.O. Box 908
Bloomington, IN 47402-0908

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Section 1: Introduction

1 Introduction

This *2017 Integrated Resource Plan* (the Plan or the IRP) is submitted by Hoosier Energy Rural Electric Cooperative, Inc. (“Hoosier Energy”) pursuant to the requirements of Rule 170 of the Indiana Administrative Code 4-7 (hereinafter referred to as the Rule). The Plan consists of two volumes. Volume I contains the executive summary, the peak demand and energy forecasts, a description of existing resources, the selection of resources, the resource portfolios and the short-term action plan as required by the Rule. Volume II contains the technical appendices with information required under the Rule.

The IRP contains five subsections. The first section (Section 1) provides an overview of Hoosier Energy and the Hoosier Energy member systems and an executive summary. The second subsection (Section 2) summarizes the energy and demand forecasts and the methodology used to develop the forecasts. The third subsection (Section 3) describes Hoosier Energy’s existing resources, both supply-side and demand-side resources. The fourth subsection (Section 4) addresses the selection of potential new resources (both supply-side and demand-side) and the screening process used. Section 5 describes the development of the FutureWorld scenarios, the portfolio optimization modeling, and the resulting least cost scenarios.

1.1 Hoosier Energy Operational Description

1.1.1 Hoosier Energy Member Systems

Hoosier Energy is comprised of seventeen member distribution cooperatives located in central and southern Indiana and one member distribution cooperative located in south-eastern Illinois. Table 1 shows the member systems that comprise Hoosier Energy.

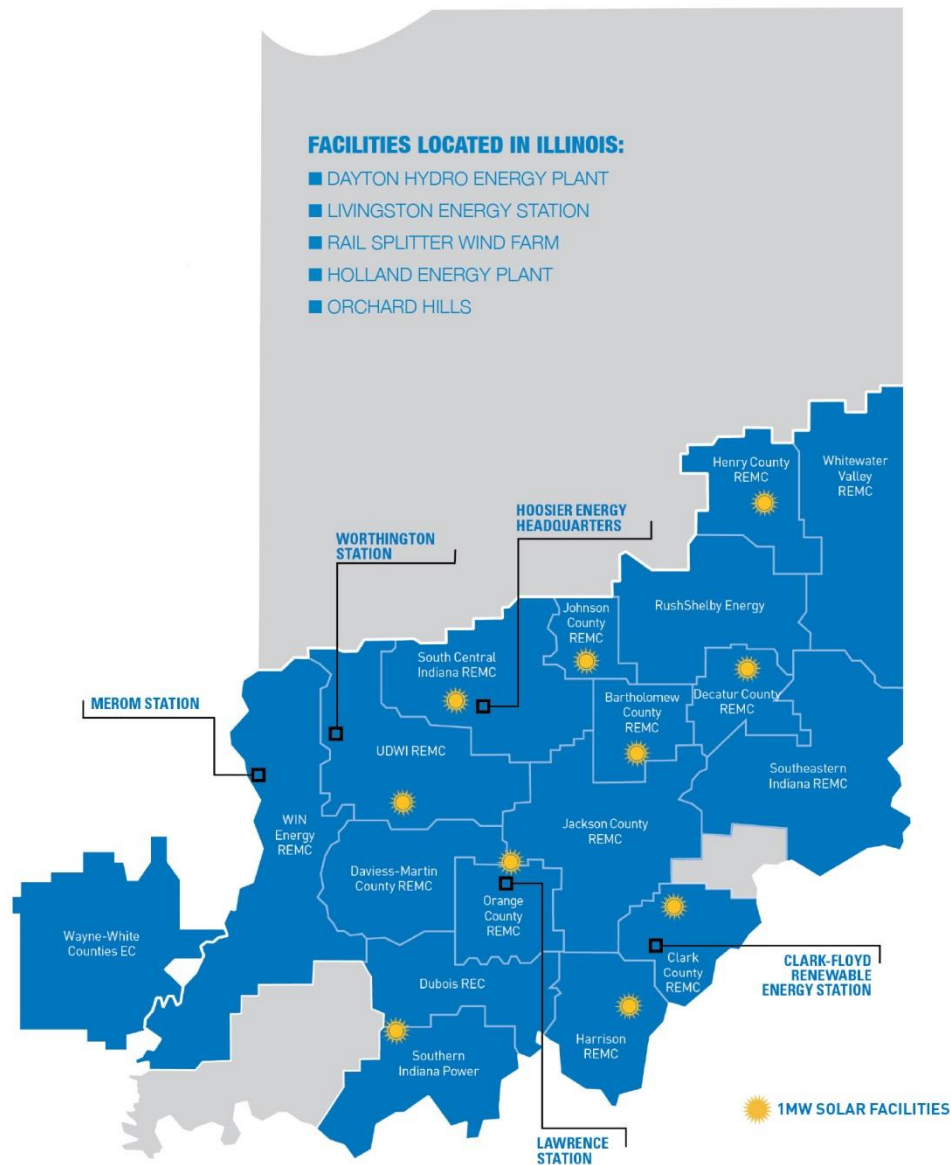
Rural Utilities Service Designation	Name of Cooperative	Location of Headquarters
Indiana 1	Utilities District of Western Indiana REMC	Bloomfield
Indiana 16	Henry County REMC	New Castle
Indiana 21	Bartholomew County REMC	Columbus
Indiana 26	Daviess-Martin County REMC	Loogootee
Indiana 27	Decatur County REMC	Greensburg
Indiana 38	Johnson County REMC	Franklin
Indiana 47	Orange County REMC	Orleans
Indiana 52	Southeastern Indiana REMC	Osgood
Indiana 60	South Central Indiana REMC	Martinsville
Indiana 72	Clark County REMC	Sellersburg
Indiana 83	Dubois REC, Inc.	Jasper
Indiana 89	Harrison REMC	Corydon
Indiana 92	Jackson County REMC	Brownstown
Indiana 99	Southern Indiana REC, Inc.	Tell City
Indiana 109	Whitewater Valley REMC	Liberty
Indiana 110	WIN Energy REMC	Vincennes
Indiana 111	RushShelby Energy REC	Manilla
Illinois 002	Wayne-White Counties Electric Coop	Fairfield, IL

Table 1: Hoosier Energy Member Systems

1.1.2 Location and Service Territory Characteristics

Hoosier Energy’s headquarters facility is located at 2501 South Cooperative Way, on the south side of Bloomington, Indiana. Hoosier Energy operates power plants in Merom, Worthington, Lawrence County and Clark County, Indiana and Beecher City and Pontiac, Illinois (detailed further in Section 3.1.1) and has transmission crews stationed in Spencer, Seymour, Rushville, Worthington, Petersburg, Poseyville, Napoleon, and English.

The approximate boundaries for Hoosier Energy’s member service territory are shown in the map:



Hoosier Energy’s member systems serve 48 counties in rural central and southern Indiana and 11 counties in southeastern Illinois. The service territory includes portions of the suburban areas

adjacent to the metropolitan cities of Indianapolis, Cincinnati, Louisville, Evansville, Terre Haute, Columbus, Bloomington and Vincennes. The major interstate highways serving these cities and Hoosier Energy's service territory are I-65, I-74, I-70, I-64 and I-69. Several major airports serve the Hoosier Energy service territory including the Indianapolis International Airport, which is located near the northern boundary of the service territory. Several railroads also cross the service area.

The terrain in Hoosier Energy's service area varies from flat to rolling farmland to heavily forested hills containing many deep ravines. This terrain is used in a variety of ways:

- Agriculture for the growing of corn, soybeans, wheat and tobacco.
- Animal husbandry for the raising of hogs, beef cattle, dairy cattle and poultry.
- Stone quarries.
- Coal mining (both strip and underground).
- Hardwood forests for logging.

Dozens of Indiana State parks, forests and fish and wildlife areas as well as portions of the Hoosier National Forest are found in Hoosier Energy's service territory. There are also three large, manmade reservoirs in the service territory, Patoka, Brookville and Monroe, which are used for recreation, water supply and flood control.

The climate in this service area is continental, with warm summers and moderately cold winters. There are four distinct seasons with an adequate growing and harvest season for most farm crops. On the northern perimeter of the service area, the monthly average temperatures range from about 28°F to 75°F, with record temperatures ranging from -27°F to 105°F.¹ The southernmost edge of the service area has monthly mean temperatures ranging from 33.0°F to 78°F, with extremes ranging from -23°F to 108°F.² The normal heating and cooling degree-days throughout the area vary as shown in Table 2.

City	Heating Degree Days	Cooling Degree Days
Indianapolis, IN	5,354	1,085
Louisville, KY	4,194	1,549
Evansville, IN	4,498	1,431
Cincinnati, OH	5,048	1,085

Table 2: Normal Heating and Cooling Degree-Days³

The normal annual precipitation for this area is approximately 42 inches per year.⁴

¹ Indianapolis Local Climatological Weather Station Reports (Midwest Regional Climate Center, average period 1981-2010, extreme period 1943-2016).

² Evansville Local Climatological Weather Station Reports (Midwest Regional Climate Center, average period 1981-2010, extreme period 1931-2016).

³ Midwest Regional Climate Center (defined NOAA normal, period 1981-2010).

⁴ Obtained from Midwest Regional Climate Center (Indianapolis Weather Station, period 1981-2010)

1.1.3 Consumer Class Breakdown⁵

The consumer mix on the Indiana portion of the Hoosier Energy system changed slightly over the 2005 - 2015 period. In 2005, 95.0% of the system's consumers were residential, while in 2015, 94.2% were residential. The number of residential consumers increased from 257,250 in 2005 to 281,173 in 2015. By the year 2036, the number of residential consumers is forecast to increase 12.9 percent to 317,455. The percentage of total residential consumers served is forecast to remain approximately the same in the year 2036 (94.1%).

In 2005, 4.9% were Commercial and Other consumers compared to 5.7% in 2015. The total number of consumers in this sector grew from 13,383 to 17,136 during this period, representing a growth of 28.0%. The percentage of Commercial and Other sector in the year 2036 is forecast to be 5.9 percent, similar to the present mix. The number of consumers in this class is forecast to increase 16.0% to 19,870 in 2036.

The total number of consumers from the Industrial sector, which is defined as loads requiring transformation greater than 1,000 kVA, increased from 164 to 206 during the 2005 through 2015 period, for a net gain of 25.6 percent. The forecast number of 202 consumers in the year 2036 indicates a decrease of 0.9 percent.

The proportions of the aggregated member energy sales are different from the consumer mix. The residential class proportion of sales decreased from 64.1% in 2005 to 58.1% in 2015 due primarily to a large increase in sales to the Industrial Sector. The actual member system residential energy sales increased 6.8% from 3,750 GWh in 2005 to 4,003 GWh in 2015. The year 2036 residential sales forecast is 4,982 GWh – 60.8% of total sales.

Hoosier Energy experienced significant growth in sales to the Industrial classification between 2005 and 2015. Energy sales increased 47.5% from 1,292 GWh in 2005 to 1,905 GWh in 2015. The portion of total sales to this sector increased from 22.1% in 2005 to 27.6% in 2015. Total energy sales proportion is forecast to be 23.7% (1,942 GWh) for the year 2036.

The proportion of sales to the Commercial and Other sector increased slightly from 13.8% of total sales in 2005 to 14.3% in 2015. Actual sales increased from 808 GWh in 2005 to 984 GWh in 2015, for an overall increase of 21.8 percent. Total energy sales of this class are forecast to be 1,271 GWh in 2036, or 15.5 percent of total sales.

In aggregate, member-system energy sales increased 17.8 percent from 5,850 GWh in 2005 to 6,892 GWh in 2015. The member-system energy sales forecast of 8,195 GWh for 2036 represents an increase of 18.9% from the 2015 value.

1.2 Summary of the Planning Process

As described in 170 IAC 4-7, the objective of the integrated resource planning process is to give the Indiana Utility Regulatory Commission (IURC) a regulatory model to ensure that the resource initiatives considered by Hoosier Energy conform with the Indiana Legislature's policy goals. The rule requires that Hoosier Energy consider conservation, load management, co-generation,

⁵ Historical statistics prior to 2011 do not include the addition of Wayne-White Counties Electric Cooperative.

distributed generation, refurbishment of an existing facility and purchase of power as alternatives to the construction, purchase or lease of an electrical generating facility.

In accordance with the Rule, the objective of the Hoosier Energy planning process was to develop a strategy for the planning period to afford Hoosier Energy flexibility and latitude in providing electric energy service to its customers. The first step in the IRP process was to prepare an analysis of the historical and forecast levels of peak demand and energy usage. Section 2 of the Plan presents Hoosier Energy's forecast of peak loads and energy consumption. The next step in the resource planning process was to assess the resources existing and potentially available to meet the energy and demand over the planning period. Section 3 details this resource assessment.

The third step in the planning process was to eliminate nonviable resource alternatives through an initial screening of all future resources identified in the resource assessment. Section 4 presents the supply-side and the demand-side resource screening processes. The fourth step was the selection of the best combination of resources that is consistent with the objectives of the IRP. Section 5 describes the resource integration and selection process.

1.3 Executive Summary of the Resource Plan

The goal of this IRP is to achieve low power supply cost, at a targeted level of low market and business risk, for its member distribution systems, while seeking a high degree of generation and transmission reliability. In developing this resource plan, Hoosier Energy considered alternative types of generation (supply-side) and end-consumer usage modification (demand-side) alternatives to seek an optimal blend of capacity resources.

This process has led to a plan that seeks to minimize member-system power supply costs and risks while maintaining a high degree of system reliability. In addition, the Plan seeks to maintain sufficient flexibility to react to changes in member system needs, load forecasts, legislative and regulatory mandates, new technologies and market price volatilities. This Plan will be reevaluated periodically to ensure that the recommended courses of action are having the desired effect and continue to be the best alternatives.

1.3.1 Public Policy Considerations

A major factor in the development of the Plan was the effect of potential legislation and/or regulatory changes. For example, additional environmental restrictions have the potential to further affect cost assumption tradeoffs between the type, quality and availability of fuel burned and the allowable emissions level at existing and future generating stations. The Plan was structured to be flexible enough to incorporate not only existing regulations but also possible further restrictions.

This plan contemplates no significant changes to the current integrated retail market, which could affect Hoosier Energy's Members. However, the plan does consider the relatively high-risk environment created by customer interest in self-generation and its impact on a utility's obligation to serve retail load.

1.3.2 Supply-Side Resource Considerations

Hoosier Energy is required to adhere to specific standards regarding resource adequacy. The overall level of generation required to maintain system integrity and reliability is of paramount importance.

In evaluating supply-side resources, the estimated capital cost and expected operating costs are two primary factors. However, a robust IRP must also consider additional factors, such as current and future environmental regulations, permit requirements, regulatory approvals and customer impacts.

Hoosier Energy has a Board Policy, adopted in 2014, that sets a target of obtaining 10% of member energy requirements from renewable resources by 2025. The Plan should also recognize the value of diversity – fuel, technology, resource type, ownership, location – to mitigate risks, such as operating, ownership and market risks.

1.3.3 Demand-Side Resource Considerations

As a cooperative, Hoosier Energy interests are aligned with its Members and its Members’ retail customers. Hoosier Energy is committed to serving Members reliably and at the lowest possible cost. This commitment is demonstrated as Hoosier Energy and Hoosier Energy’s 18 Members offer an array of energy efficiency and demand-side management programs to member-consumers. Current programs are found at the following link:

<http://teamuptosave.com/>



The image is a promotional banner for the 'Team Up' program. It features a dark green background at the bottom. On the left, the text 'TEAM UP' is written in large, bold, black letters, with 'Together We Save.' in smaller green text below it. To the right of the text is a green plug icon with a grey socket icon below it. Further right, the text 'Providing winning ways for you to save energy and money with the help of your local electric cooperative!' is written in a smaller, grey font. In the top right corner, there is a grey button with the text 'Find Us on Facebook' in white.

Current Roster: Energy-Saving All-Star Lineup



Energy-saving programs and rebates may vary, depending on the participating electric cooperative.

[Click here](#) for additional resources to help you save energy and money.

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Further detail on the energy efficiency and demand response programs can be found in the 2016 Demand Side Management Report, which is included in this IRP as Appendix F. The DSM programs result from work with GDS Associates and Summit Blue Consulting to develop the Energy Efficiency & Demand Response Potential Report, which was included as Appendix A1 in the 2014 Hoosier Energy IRP. The Potential Report, which has been updated twice over the last five years, provides detailed descriptions and analysis of all demand-side programs considered and recommended for Hoosier Energy.

1.3.4 Conclusions

Based upon current load forecast and existing and future resource assessment, Hoosier Energy expects to continue to fulfill its future resource needs through a combination of company-owned generation, long-term power purchases and sales, and short-term purchases and sales. While the Midcontinent ISO adds liquidity and transparency to the wholesale market, the availability and price of market power can be volatile especially during peak periods as electricity requires instantaneous production/consumption (due to a lack of capability to economically and effectively store). Therefore, while short-term power purchases may, at times, be a least-cost alternative, ownership of generation and/or long-term power purchases are a necessary component of this least cost plan.

Hoosier Energy will continue to work with Member Systems to offer a menu of demand-side measures to promote the efficient use of resources. This includes the wholesale tariff, which was

re-evaluated in 2017, with implementation of updates scheduled for April 2019, and provides incentives for both demand response program participation and load shifting. Hoosier Energy's demand response and energy efficiency market potential study and its subsequent updates remain an integral part of the Plan.

In compliance with Board policy, Hoosier Energy has included the addition of a significant amount of renewable resources within the Plan. Consistent with the overall portfolio approach to resource planning, Hoosier Energy has both owned and purchased power from renewable resources.

1.4 Hoosier Energy's Short-Term Action Plan

Section 9 of the Rule requires inclusion of a short-term action plan if Hoosier Energy anticipates taking action or incurring expenses on a specific resource option prior to the filing of the next integrated resource plan. As discussed in more detail within this integrated resource plan, based upon the current load forecast, power and gas market expectations, known environmental regulations and supply-side and demand-side resource mix, Hoosier Energy expects to have sufficient resources for the immediate future. However, Hoosier Energy expects to continue the following efforts:

1. Implementation of current and potentially new, cost-effective demand response and energy efficiency programs.
2. Pursuit of cost-effective, renewable resources that provide fuel and resource diversity and help hedge against future environmental regulation risk.
3. Management of short-term capacity and/or energy excess or needs through the wholesale power market using current market hedging mechanisms. Market interaction remains an integral part of the integrated resource plan and will continue to be an appropriate and economical complement to Hoosier Energy's existing resource mix.

This integrated resource plan does identify a capacity need in the mid-2020s. During the next five years, Hoosier Energy may begin analyzing opportunities to address this need.

1.5 Comparison to Prior Short-Term Action Plan

In the 2016 Update to its 2014 Integrated Resource Plan filing, Hoosier Energy submitted the following short-term action plan:

1. Hoosier Energy will use market purchases to meet short term needs during 2017. In addition, Hoosier Energy will continue to employ hedging strategies to reduce market price risk.
2. Hoosier Energy will continue to develop and implement cost effective demand response and energy efficiency programs in conjunction with member systems.
3. Hoosier Energy will continue to pursue cost-effective, renewable resources to achieve the Board target of 10% of member energy requirements by 2025. Hoosier Energy also expects increased interest from Commercial & Industrial customers to add renewable resources.
4. Hoosier Energy will continue to monitor and analyze potential environmental regulations that may impact intermediate and long-term operations.

5. Strategist modeling performed by GDS Associates indicates the next major resource increment is required around the years 2023/2024.
6. Hoosier Energy will perform additional analysis, including an assessment of existing resources, as part of the 2017 Integrated Resource Plan.

After the 2016 Plan was filed, Hoosier Energy has continued to pursue the strategies described in its short-term action plan, including implementation of demand response and energy efficiency programs. The programs and their results are contained in the 2016 Demand Side Management Annual Report, which is attached as Appendix F to this IRP.

Hoosier Energy has continued to add cost-effective renewable resources to its resource portfolio. For example, Hoosier Energy has added 10 MW of solar generation since 2014, with plans, which have been approved by the Board, to add an additional 291 MW of renewable resources by the end of 2020. The addition of these renewable resources will add fixed price resources to the portfolio, thereby reducing market price risk.

Section 2: Energy and Demand Forecasts

2 Energy and Demand Forecasts

Pursuant to 170 IAC 4-7 Sections 4 and 5, this section presents the energy and demand forecasts for Hoosier Energy. The section is broken into six subsections, and is supported by several appendices. As an introduction, Section 2.1 describes the Hoosier Energy forecasting process. Section 2.2 presents the methodology used to create the forecasts. Section 2.3 and Appendices A1 through A7 present the Base, High, Low, Base-Upper Normal, Base-Lower Normal, Base-Mild and Base-Severe forecasts. Section 2.4 presents the data used to develop the forecast. Section 2.5 and Appendix B present the load shape and electricity consumption patterns for the Hoosier Energy system. Section 2.6 presents a summary of Hoosier Energy's forecasted peak demand and energy for the Base-Upper Normal, High and Low scenarios.

2.1 Forecasting Process

Hoosier Energy compiles a *Power Requirements Study* (PRS) on a two-year cycle. The PRS meets all requirements as established in the Hoosier Energy Power Requirements Study Work Plan and the Rural Utilities Service Rule 1710, sub-part E, sections 1710.200 through 1710.210. The PRS fully documents the forecast of electric energy sales and peak demand for Hoosier Energy. The development of the PRS is a joint effort between the staff at Hoosier Energy and its member systems, with contributions and review from RUS.

The PRS provides an empirical basis for forecasting generation capacity, forecasting substation capacity and planning transmission facilities. The PRS formalizes the analysis of the need for electric energy and demand for the territory served by the Hoosier Energy member systems over a 20-year period. The PRS provides a systematic investigation of the historical growth experienced by the member systems served by Hoosier Energy. This analysis gives a better understanding of the unique features of the individual member system service areas, which allows for a better background for forecasting electrical load growth, and a more accurate perspective on the status of the member systems.

In the end, this study allows for the development of a forecast that meets three specific needs:

- Provide a basis for determining generation, transmission and distribution system modifications and capital investments;
- Develop a consistent framework for Hoosier Energy and the member systems to plan and project system-wide requirements and improvements; and
- Satisfy the requirement made by RUS that generation and transmission cooperatives provide empirical studies of each distribution cooperative that are consistent with system projections, and that reflect an understanding of the system, its loads, its member systems, and its power supply.

The approval process for the PRS includes approval of each member system's PRS by its board of directors, approval of the Hoosier Energy PRS by its board of directors, and review of the PRS by RUS. Hoosier Energy's 2017 PRS dated October 2017 was officially approved by the Hoosier Energy Board of Directors at the November 2017 meeting, as well as reviewed and approved by RUS as of December 20, 2017.

For the IRP, the numbers as presented are based upon the 2017 PRS, which is the active PRS. The 2017 PRS is a 20-year forecast of expected member system load and, as such, covers the period

from 2016 through 2036. For purposes of the IRP, Hoosier Energy assumed load growth of 0.6% in 2037, which is an extension of the expected growth rate from 2030 through 2036.

2.2 Methodology

This section recapitulates the basic methodology used for the Hoosier Energy demand and energy forecast development. A full explanation of the methodology can be found in the PRS.

2.2.1 Description of the Energy Models

Residential

The Hoosier Energy Residential Energy Sales Model (HERESID) is simply the summation of the results from the individual member system’s econometric Residential Model (RESID). Equation (2.1) shows this summation.

$$\text{HERES}_t = \sum_i \text{RESALES}_{it} \quad (2.1)$$

Where:

- i = A subscript representing the member system;
- t = A subscript representing annual data;
- HERES = Annual Hoosier Energy Total Member Residential Energy Sales; and,
- RESALES = Annual Individual Member System’s Residential Energy Sales.

Each member system’s Residential Energy Model (RESID) is represented by three equations. The values of average residential energy use per consumer per month, real average residential price of electricity, and the number of residential consumers are determined by the operation of the simultaneous solution of this system of three equations. In other words, these three variables are determined within the model, and the three-equation system will allow for the development of forecasts for all three.

The three-equation system is shown in Equations (2.2) through (2.4).

$$\ln \text{RAUSE}_{it} = a_0 + a_1 \ln \text{RAUSE}_{i,t-1} + a_2 \ln \text{RRPE}_{it} + a_3 \ln \text{RPCI}_{it} + a_4 \ln \text{HDD}_{it} + a_5 \ln \text{CDD}_{it} + a_6 \text{XR}_{it} \quad (2.2)$$

$$\ln \text{RRPE}_{it} = b_0 + b_1 \ln \text{RAUSE}_{it} + b_2 \ln \text{RADSK}_{it} + b_3 \ln \text{RAWPC}_{it} + b_4 \text{YR}_{it} \quad (2.3)$$

$$\ln \text{RC7}_{it} = c_0 + c_1 \ln \text{POP}_{it} + c_2 \text{ZR}_{it} \quad (2.4)$$

Where:

- i = A subscript representing the member system;
- t = A subscript representing annual data;

RAUSE	=	Average electricity use per consumer per month in the residential sector;
RRPE	=	Real average price of electricity in the residential sector;
RPCI	=	Real average per capita income earned by the people living in the service area;
HDD	=	Annual value of service area heating degree-days;
CDD	=	Annual value of service area cooling degree-days;
XR	=	Other variables that influence average use, such as alternative fuel prices and agricultural production;
RADSK	=	The actual real distribution system cost to operate and maintain the distribution system excluding wholesale power costs;
RAWPC	=	The average real wholesale cost of electricity paid by the cooperative;
YR	=	Other variables that may affect price;
RC7	=	Number of residential consumers;
POP	=	Population in the service area;
ZR	=	Other variables that may affect the number of consumers.

Commercial, Industrial and Other

The Hoosier Energy Commercial, Industrial and Other Energy Sales Model (HECIO) is the summation of the individual member system's results for these classes. The HECIO is shown in Equation (2.5).

$$HECIO_t = \sum_i MCIOS_{it} \quad (2.5)$$

Where:

i	=	A subscript representing the member system
t	=	A subscript representing annual data;
HECIO	=	Annual Hoosier Energy Total Member System Commercial/Industrial/Other Energy Sales
MCIOS	=	Annual Individual Member System Commercial/ Industrial/Other Energy Sales

For each of the member system's Commercial, Industrial and Other class forecast, a judgmental approach was employed. The judgmental approach was selected for the following four reasons:

1. Each cooperative contributed a realistic potential growth estimate. These estimates were developed through a review of past patterns, existing and near-term developments, and expected future growth patterns.
2. The erratic nature of the historical data and the composition of the varied types of loads in this class make it difficult to explain the growth in sales for the Commercial, Industrial and Other class accurately using an econometric model.
3. The growth in the Commercial, Industrial and Other class is highly dependent upon new business developments rather than past patterns of growth.

4. Growth of the Commercial, Industrial and Other class can be best estimated by those most familiar with the area, such as the REMC Managers and Hoosier Energy's representatives. Therefore, even if an econometric model were used, the results would be largely dependent upon information regarding new businesses and industries locating in the service area.

The strategy used in developing forecasts for the Commercial, Industrial, and Other sectors included three steps:

1. Request each REMC Manager or PRS representative to review current and expected sales and consumers conditions for each of these classifications. In addition, staff persons from each member system compiled industrial data to allow completion of Hoosier Energy's RUS Form 345⁶.
2. Meet individually with each member system to exchange ideas and information. Historical growth patterns of the Commercial, Industrial, and Other sectors were examined in detail to develop future expected growth potential for each member system.
3. The final step was to compile the expected growth potential values, calculate the future values, and determine if these values represent a realistic future of these sectors. The industrial sector forecast is specifically developed from individual consumer forecasts assigned to this sector. The values for the individual member system's Commercial, Industrial and Other classifications were reviewed by each member system for final approval.

2.2.2 Description of the Demand Models

Hoosier Energy System Demand

To develop a Hoosier Energy demand forecast, information from each member system was combined with Hoosier Energy information. This information includes:

1. Member system non-coincidental peak—winter season,
2. Member system non-coincidental peak—summer season,
3. Member system coincident peak—winter season,
4. Member system coincident peak—summer season,
5. Hoosier Energy actual 30-minute coincident demands,
6. Hoosier Energy actual 60-minute coincident demands without losses, and
7. Hoosier Energy actual 60-minute coincident demands with losses.

Once the collection of these variables is completed, the Hoosier Energy demand forecasts can be developed. First, the member system demands are aggregated. Next, the total is adjusted by the Hoosier Energy estimated demand loss factor and the Hoosier Energy 60-minute to 30-minute time ratio adjustment factor (the 60/30 time factor ratio). Equations (2.6) through (2.9) were used to aggregate the member systems' forecast 30-minute demands.

⁶ These forms were developed for all accounts having a transformation greater than 1,000 kVA.

$$\text{HENWP}_t = \sum_i \text{FWINPEAK}_{it} \quad (2.6)$$

$$\text{HENSPT}_t = \sum_i \text{FSUMPEAK}_{it} \quad (2.7)$$

$$\text{HECWP}_t = \sum_i \text{FCWINPEAK}_{it} \quad (2.8)$$

$$\text{HECSP}_t = \sum_i \text{FCSUMPEAK}_{it} \quad (2.9)$$

Where:

- i = A subscript representing the member systems;
- t = A subscript representing annual data;
- FWINPEAK = Member system winter season non-coincident peak;
- FSUMPEAK = Member system summer season non-coincident peak;
- FCWINPEAK = Member system winter season coincident peak;
- FCSUMPEAK = Member system summer season coincident peak;
- HENWP = Hoosier Energy winter season 30-minute non-coincident peak without losses;
- HENSPT = Hoosier Energy summer season 30-minute non-coincident peak without losses;
- HECWP = Hoosier Energy winter season 30-minute coincident peak without losses; and
- HECSP = Hoosier Energy summer season 30-minute coincident peak without losses.

Once the aggregation of the member systems' coincident demands is completed, the historical Hoosier Energy 60/30 time factor ratio is developed using Equation (2.10).

$$\text{HETIME}_t = \text{ACT60HE}_t \div \text{ACT30HE}_t \quad (2.10)$$

Where:

- t = A subscript representing annual data;
- HETIME = Hoosier Energy 60-minute to 30-minute time ratio adjustment factor;
- ACT60HE = Actual Hoosier Energy 60-minute metered coincident demand without losses;
- ACT30HE = Actual Hoosier Energy 30-minute metered coincident demand without losses.

Through a judgmental process and analysis of the historical Hoosier Energy 60/30 time factor ratio, a value for this ratio is projected for the forecast years and applied to the aggregated member systems' future 30-minute demand values. This process yields a 60-minute Hoosier Energy coincident and non-coincident demand value without transmission losses. These demands are developed using Equations (2.11) through (2.14).

$$\text{HE60NWP}_t = \text{HETIME}_t * \text{HENWP}_t \quad (2.11)$$

$$HE60NSP_t = HETIME_t * HENSP_t \quad (2.12)$$

$$HE60CWP_t = HETIME_t * HECWP_t \quad (2.13)$$

$$HE60CSP_t = HETIME_t * HECSP_t \quad (2.14)$$

Where:

- t = A subscript representing annual data;
- HE60NWP = Hoosier Energy winter season NCP without losses;
- HE60NSP = Hoosier Energy summer season NCP without losses;
- HE60CWP = Hoosier Energy winter season CP without losses;
- HE60CSP = Hoosier Energy summer season CP without losses.

Next, a future annual demand loss factor is predicted through examination of the historical annual demand loss factors. Historical demand loss factors represent the annual average demand loss factors which occurred, calculated as the annual average of the monthly demand losses experienced. Monthly demand loss factors are determined by dividing the difference between the 60-minute demands with losses and actual 60-minute demands without losses by the actual 60-minute demands with losses. After the 60-minute demand values without losses are calculated and a demand loss factor is determined, the final Hoosier Energy 60-minute peak demand with losses included is determined by applying Equation (2.15).

$$HEFPEAK_{xt} = HEPEAK_{xt} * [1/(1 - HELOSS_t)] \quad (2.15)$$

Where:

- t = A subscript representing annual data;
- x = A subscript representing the various types of demands.

When:

- x = 1 it represents the non-coincident winter season;
- x = 2 it represents the non-coincident summer season;
- x = 3 it represents the coincident winter season; and,
- x = 4 it represents the coincident summer season;

- HEPEAK = The various peak values developed via aggregation without losses included (example dependent upon “x”, HE60NWP, HE60NSP, HE60CWP or HE60CSP);
- HELOSS = Hoosier Energy demand loss factor due to member system load;
- HEFPEAK = Hoosier Energy 60-minute peak demand with losses included.

The equations (2.6) through (2.15) are also used to forecast Hoosier Energy peak seasonal demands created by single temperature extremes. The forecast Hoosier Energy peak seasonal demands created by single temperature extremes represent the “Extreme Case” demand forecast. In contrast, the forecast Hoosier Energy peak seasonal demands created by expected, or normal, temperatures represent the “Normal Case” demand forecast.

Individual System Demands

To develop a peak demand forecast for each member system, relevant historical information was collected for the years 1975 to 2015. This information was used to determine the relationship between kWh sales and kW demands. The analysis included the following information:

- Non-coincident peak winter season (October through March);
- Non-coincident peak summer season (April through September);
- Coincident peak winter season (October through March);
- Coincident peak summer season (April through September); and
- Total annual electric energy sales.

Non-coincident peak is the sum of the maximum demand recorded at each substation. Coincident peak is the member systems' contribution to Hoosier Energy's peak demand. Accordingly, coincident peak demand is the sum of demands recorded at each of the member system substations during the same hour of Hoosier Energy's peak. This data was applied in the calculation of the coincident factor analysis.

The first step in the coincident factor analysis is to calculate the member systems' historical load factors, which are found by using Equation (2.16).

$$ALF = [TP / (PEAK * HRS)] * 100 \quad (2.16)$$

Where:

- ALF = Annual load factor;
- TP = Total member system energy purchases;
- PEAK = Annual non-coincident member system peak kW; and
- HRS = Number of hours in the year.

The second step is to determine the relative seasonal adjustment factor, which is the percentage of summer peak value to winter peak. The relative seasonal factor is found by using Equation (2.17).

$$RSF = (SUMPEAK / WINPEAK) * 100 \quad (2.17)$$

Where:

- RSF = Member systems' relative seasonal factor;
- SUMPEAK = Member systems' summer seasonal non-coincident peak value (April through September in year t);
- WINPEAK = Member systems' winter seasonal non-coincident peak value (October in year t-1 through March in year t).

The third step is calculation of the historical coincident factor, which is found by using Equation (2.18).

$$CF_i = (CPEAK_i/NCPEAK_i) * 100 \quad (2.18)$$

Where:

- i = Season (winter or summer);
- CF = Coincident factor;
- CPEAK = Member systems' coincidental peak in the month of Hoosier Energy's coincidental peak;
- NCPEAK = Member systems' non-coincidental peak in the month of Hoosier Energy's coincidental peak.

The load factor, the seasonal adjustment factor, and the coincident factors are used as a basis to forecast the system peak demand for each member system. The system peak demand values are based upon the historical patterns seen in these variables in conjunction with information provided by the REMC/REC representative.

The first step in determining the member systems' forecast system peak demand values is to project the future system winter seasonal non-coincidental peak. Equation (2.19) is used to determine the future system winter seasonal non-coincidental peak by applying future annual load factors and energy purchases.

$$FWINPEAK = FTP / [(FALF/100) * HRS] \quad (2.19)$$

Where:

- FWINPEAK = Forecast member system winter season non-coincident peak;
- FTP = Forecast member system total energy purchases;
- FALF = Forecast member system annual load factor, based on the interpretation of historical trends;
- HRS = Number of hours in the year.

The next step is calculating the future summer seasonal non-coincident peak demand for each system using a forecast relative seasonal factor and the estimated non-coincident winter peak demand from Equation (2.19). Equation (2.20) shows this formula.

$$FSUMPEAK = FWINPEAK * (FRSF/100) \quad (2.20)$$

Where:

- FSUMPEAK = Forecast member system summer seasonal non-coincident peak;
- FRSF = Forecast relative seasonal factor input based on expected future trends;
- FWINPEAK = As defined above.

Finally, the coincident seasonal peaks are found by applying the summer and winter coincident factors to the calculated non-coincident peaks. These formulas are listed below as Equations (2.21) and (2.22).

$$FCWINPEAK = CF_w * FWINPEAK \quad (2.21)$$

$$FCSUMPEAK = CF_s * FSUMPEAK \quad (2.22)$$

Where:

- FCWINPEAK = Forecast member system coincident winter seasonal peak;
CF_i = Member system coincident factor when:
i=w denotes winter
i=s denotes summer
FCSUMPEAK = Forecast coincident summer seasonal peak;
FWINPEAK = As defined above;
FSUMPEAK = As defined above.

2.2.3 Alternative Forecast Scenarios

As a part of Hoosier Energy's forecasting process (the PRS), the forecast process is "ranged based", rather than based upon a single value forecast. Several forecast scenarios are then developed allowing for review of the model's sensitivity to different economic and weather input assumptions. For the most recent PRS, Hoosier Energy developed seven alternative energy forecasts: *Base-Normal*, *Base-Upper Normal*, *Base-Lower Normal*, *Base-Severe*, *Base-Mild*, *Low and High Cases*. For the residential sector, the scenarios are differentiated based upon fluctuation of population, real per capita income, fuel prices, and weather. For the commercial and industrial sectors, the scenarios were differentiated based upon variation in the number of consumers and energy growth rates. As explained in Section 2.7, Hoosier Energy is using the Base-Upper Normal forecast as its base forecast in its IRP modeling.

The following factors were considered in order to determine the magnitude of changes to the variables to produce the alternative cases:

- The observed change in the variables over the historical period that the forecast is based;
- The range of variation that exists for the variable;
- The elasticity of the driving variables in the models (i.e., the size of the coefficient compared with the coefficient of the other variables included in the model).

Hoosier Energy's ultimate goal in making changes to the variable assumptions was to establish alternative scenarios that represent conditions that could realistically occur. This pragmatic approach was also used in determining the magnitude of fluctuation for the commercial and industrial classes' alternative scenarios.

The most probable energy case is called the *Base-Normal Case*. The Base Case was developed using the most likely input assumptions. These assumptions are based on extensive research involving the member systems' knowledge of the area, utility operational databases and forecasts for variables provided by many external sources. After the Base Case is completed, the alternative scenario cases are developed.

The first alternative scenario, the *Low Case*, represents the forecast under poor economic development conditions. The Low Case scenario was developed for the residential sector by a) reducing the real per capita income and fuel price growth rates by 1 percent and b) assuming the population growth to be 0.5 percent lower than under the Base Case. To determine the Low Case scenario forecast for the commercial class, the base case growth rates for both the number of consumers and energy growth were reduced by 0.5 percent with a lower bound to be zero. To determine the Low Case scenario forecast for the industrial class, the number of consumers for each system was reduced by one for the entire forecast period, with a lower bound to be zero. Under this scenario the energy for the industrial class was decreased in the initial year using a step function. The energy was decreased by an amount equal to the average industrial consumer's energy use in the calibration year. In addition, the energy was decreased by 0.5 percent annually over the remaining forecast period.

The *High Case* scenario represents robust economic development conditions and is a mirror image of the Low Case. In the High Case, the residential sector was forecast assuming the real per capita income and fuel price growth rates increased by a full percentage point greater than the Base Case and the population growth was 0.5 percent greater than under the Base Case. For the commercial class High Case scenario, the number of consumers and energy growth were increased by 0.5 percent over the Base Case. For the industrial class High Case scenario, the number of consumers for each system was increased by one for the entire forecast period. The energy for the industrial class was increased in the initial year using a step function.

Base-Upper Normal, *Base-Lower Normal*, *Base-Severe* and *Base-Mild* scenarios represent the economic Base Case conditions under varying weather conditions. The Base-Upper Normal and Base-Lower Normal Cases represent base economic conditions with alternate parameters for heating degree days (HDD) and cooling degree days (CDD) developed representing an upper bound of normal weather, as well as lower bounds for each member system. This range provides a forecaster a means to examine how the forecast may fluctuate within a normalized weather range. The Base-Severe case represents the economic Base Case conditions under extreme cold and hot weather conditions. The Base-Severe Case was developed through use of the maximum annual heating and cooling degree-day values recorded during the historical period for the service area. The Base-Mild Case was created using the economic base conditions under mild weather conditions. Mild weather conditions were defined as the annual minimum heating and cooling degree-day values for the service area during the historical period. The primary benefit of seven different scenarios is the allowance for both economic and weather model sensitivity analyses.

For each energy scenario, two demand scenarios are examined. These are based upon historical average and extreme annual system load factors. The demand scenarios represent the effects of typical weather and extreme single temperature weather conditions on the system under the various energy scenarios established. As with the energy forecasts, the variety of demand scenarios allows weather sensitivity analysis of the system demand.

2.2.4 Evaluation of Model Performance

Having the models backcast the period from which they were developed validates how well the residential energy models perform. Once developed, the backcast and the actual data are plotted and visually examined. This analysis assists in determination of whether the model can replicate historical patterns. Examining the model R² values and performing a root mean square percent error (RMSPE) analysis then statistically validates the residential energy model. The R² for each

model reflects the variation in the dependent variable explained by the independent variables being used. This reflects the goodness of fit of the regression models. The RMSPE gives a summary of how close the model's predicted values are to the actual, assuming no error in the input assumptions. The RMSPE is calculated using the Equation (2.23).

$$\text{RMSPE} = \left\{ \frac{1}{n} \sum_i [(Y_i - Y_i')^2 / Y_i^2] \right\}^{(1/2)} \tag{2.23}$$

Where:

- n = The number of observations;
- Y_i = The actual value of the variable projected under the modeling framework, i=1, . . . , n;
- Y_i' = The predicted value.

RMSPE was calculated for the historical period from which the econometric models are developed. The RMSPE in Table 3 illustrates the average performance range of the various individual regional econometric models.

Within Sample Period (1975-2015)		
Region 1	2.30%	to 5.12%
Region 2	1.54%	to 4.42%
Region 3	2.37%	to 3.96%
Region 4	1.41%	to 3.33%
Region 5	1.40%	to 3.35%
Overall Average	3.05%	

Table 3: Average Estimated Root Mean Square Percent Error

The methodology employed to forecast the Commercial, Industrial and Other Sectors relies on individual member system growth rates, and empirical evidence supplied by the member systems. As such, the methodology does not lend itself to verification of the method's performance. However, Hoosier Energy does have confidence in the Commercial, Industrial and Other Sector forecasting method. The veracity of the approach is confirmed through the comparison of the RUS Form 7 energy and demand breakdowns. Historically, the Hoosier Energy forecast has fallen well between the High and the Low Scenarios.

2.2.5 Justification of Forecasting Approach

Hoosier Energy prefers an econometric modeling approach to forecast the Member Systems' residential energy sales. Other forecast modeling methodologies, such as trend-line analysis, time series models, and end-use models, have strengths and weaknesses. Trend-line and time series methods are entirely based on past trends of electric energy sales. As such, these approaches do not incorporate the impact of changing population and/or changing average incomes, in influencing these trends. End-use models are theoretically appealing because they focus on appliance use at the consumer level. However, end-use models require an extensive investment in consumer surveys over several years. Once these sizable databases have been developed, an understanding

of the appliance usage patterns and events shaping them is necessary before an accurate forecasting model can be developed.

An econometric model simultaneously considers the historical impact of certain variables on residential electric energy sales. These variables can include population, per capita income, weather, alternate fuel prices, average residential electric price, and system costs. Although the development data for an econometric model is time consuming, the information required for the econometric approach is available at low cost from published government sources and the consumer billing records.

As with all econometric models, the Residential Sub-model equations will be re-estimated to incorporate new data as it becomes available, including impacts of defined demand-side management programs. This process will involve updating the database and exploring the need to include additional variables to reflect changes in average residential use and the number of consumers. The member systems and Hoosier Energy will continue to cooperate to ensure that the PRS review, data development and revisions reflect a consensus. Hoosier Energy will also continue to evaluate possible alternative methodologies for both energy and demand forecasting.

2.2.6 Weather Normalization

Weather is a primary parameter impacting Hoosier Energy's energy and demands, as well as a key driver contributing to future movement of these components. The incorporation of the effects of weather into the future Hoosier Energy forecast is completed within the PRS. Ultimately, the IRP results are driven by the PRS energy and demand results.

In the PRS, the effects of weather on future energy and demand are composed of two distinct processes. The first process is tied to degree day analysis as related to energy and the second being single-temperature tied to peak demands. The energy forecast is developed using econometric modeling and is accomplished on a per member system basis. Hoosier Energy forecast energy is an aggregated result of each individual system's econometrics energy forecast. Within each system model the two important variables are heating and cooling degree-days (HDD and CDD, respectively). These variables represent the relationship, as established in the modeling process, between energy and weather for the service area being forecast.

Reaching beyond a "single-point based" long-term forecast, the methodology used within the PRS is "range based". This methodology enhances the forecaster's understanding of the impacts of key parameter variances such as weather on the movement of the forecast. In addition, this "range based forecast" provides the user some flexibility in selection of the final forecast values to be used in supporting subsequent analysis. Within the PRS, six alternative basic scenarios are established providing general examination of weather and economic flexibility from the established "base case". Four of these six are alternative base scenarios demonstrating weather sensitivity on the system's energy component.

Hoosier Energy, as with most companies, develops its Base Case forecast based upon "normal" weather conditions. Hoosier Energy defines "normal" weather conditions as the average weather that has occurred over a past period. This follows the general definition as established by the NOAA and published in their monthly and annual weather reports. To drive the member systems' econometric models, "normal" HDD and "normal" CDD variables are developed for each of the service areas. This is accomplished by determining which NOAA defined weather divisions border or cover the various service areas being reviewed. Historical average HDD and CDD across the

selected weather divisions are developed by using NOAA values and are then defined as the “normal” weather condition. These defined “normal” HDD and CDD values, specific to the various service areas, drive the econometric models to yield an energy forecast. The individual member system energy forecasts are then aggregated to produce a Hoosier Energy total system “normal” weather energy forecast.

To better understand sensitivity and movement within the defined “normal” weather band, as related to energy movement, the two case scenarios of “Base-Upper-Normal” and “Base-Lower-Normal” are developed. Establishment of the HDD and CDD values for these scenarios follows the methodology used in defining the “normal” weather conditions as described above. However, an additional step is incorporated allowing examination of more detailed movement within the “normal” weather classification, creating upper and lower ranges of HDD and CDD that are still considered “normal.” This is accomplished through statistical standard deviation analysis on historical weather movement of these parameters within the normalized range. Ultimately this provides a means in which to examine how the forecast may fluctuate as well as fine-tune the base energy forecast while remaining within the “normalized” weather range.

Finally, to comprehend the full impact of weather sensitivity on energy and demand of the system, “Base-Severe” and “Base-Mild” scenarios are created. The Base-Severe case represents the economic Base case conditions under annual extreme cold and hot weather conditions. This is created by using the annual maximum heating and cooling degree day values which occurred over the historical study period. The Base-Mild case represents the economic Base case conditions under annual mild weather conditions. This is created by using the annual minimum heating and cooling degree days which occurred over the historical study period. Results from these scenarios provide an expanded perception of weather sensitivity, while maximizing the capability of using a “ranged based” long-term forecast.

Similarly, demand is temperature normalized. The demand temperature normalization process is completed on a per system basis and aggregated to obtain demand at the Hoosier Energy level. The demand methodology uses a combination of forecast energy values and forecast annual system load factors. Accordingly, no specific weather variable is used directly in the development of the demand value. Weather impacts are incorporated by reviewing the historical annual load factors for each system to determine a typical and an extreme load factor. Since the typical load factor represents what is most likely to happen, it also represents a “normal” weather demand. The extreme load factor represents demand conditions that may exist on the system under single-temperature, extreme weather conditions, and represents the “extreme” weather scenario. Through this method, a demand range is established representing normal and extreme demands for each case scenario.

2.3 Forecasts

The forecasts generated by the PRS can be found in Appendices A1 through A7.

Appendix A1 contains the Base Upper-Normal scenario demand and energy forecasts for a 20-year period for the Hoosier Energy System, and for its individual member systems. These forecasts are divided based upon Hoosier Energy customer class, the member systems’ customer classes and the member systems in aggregate.

Appendices A2, A5, A6 and A7, respectively, contain the Base-Normal, Base-Lower Normal, Base-Severe and Base-Mild Case demand and energy forecasts for a 20-year period for the Hoosier Energy System. These forecasts incorporate weather variations rather than economic and/or demographic growth variations.

Appendix A3 contains the High Case demand and energy forecasts for a 20-year period for the Hoosier Energy System. These include forecasts by Hoosier Energy customer class and the member systems in aggregate.

Appendix A4 contains the Low Case demand and energy forecasts for a 20-year period for the Hoosier Energy System. These include forecasts by Hoosier Energy customer class and the member systems in aggregate.

Energy values shown in Appendices A2, A3 and A4 assume normal weather conditions.

2.4 Forecasting Data

An integral part of the development of a database for the analysis of electricity sales is the construction of the demographic, economic, and weather variables for each member system's service area. Since operating statistics are already recorded for the service area, the database begins with this reliable set of historical information. The challenge is compiling the remaining variables, which are gathered from external sources (e.g., the U.S. Census Bureau) and not differentiated on the same basis (i.e., the same geographic definition) as the member system data. Rather, the auxiliary information is collected on a county, state, or weather division basis. Therefore, compilation of this information requires extensive manipulation to reflect the activity in the service area, usually a combination of sub-county regions.

The data needed to produce the forecasts can be broken down into these categories:

- Operating Statistics
- Demand-Side Management (DSM) Statistics
- Population Information
- Income Information
- Weather Data
- Fuel Prices
- Agricultural Variables
- Other Variables

Each of the following sections describes the data development in detail.

2.4.1 Operating Statistics

Operating statistics reflecting historical sales, revenues, and consumers of each member system were collected from two major sources – RUS and CFC Form 7s, and when available, the United States Department of Agriculture Rural Electrification Administration Informational Publication

201-1 (formally identified as Bulletin 1-1) entitled Annual Statistical Report, Rural Electric Borrowers. Monthly and annual data are reported on RUS Form 7 and annual figures are reported in Publication 201-1. Two sources of operating statistics allowed for the implementation of a validation methodology. If substantial differences between the two sources existed, the cooperative's records were checked to identify the reason for the discrepancy.

For previous PRS studies, each member system provided monthly kWh sales, revenues, and the number of consumers by class. The consumer categories include:

- Residential (includes year-round and seasonal residential);
- Commercial/Industrial Small (non-residential customers with transformation less than or equal to 1,000 kVA);
- Industrial (non-residential customers with transformation greater than 1,000 kVA); and,
- Other electric service (irrigation sales, public street and highway lighting sales, and other unclassified sales).

While the PRS Energy Model was estimated using annual data, the collection of monthly data was also important to allow identification of reclassifications and annexations. The monthly data also provided another source of data to check whether or not observed annual outliers represented an incorrect data entry or an unusual occurrence. In addition, RUS required this monthly data report as part of the PRS document.

Several variables reported are given in nominal dollar values, such as operating deductions, the cost of power, actual distribution system costs and revenues received from the consumer class. Nominal dollar values reflect inflation and the real change in price levels. Therefore, in all the equations, all dollar values have been deflated by the Consumer Price Index (CPI), with a base period of 1982-1984, to reflect real rather than nominal relationships.

To stay abreast of Demand-Side Management (DSM) activity, Hoosier Energy collects information per program per member system annually. This information is applied where necessary to the historical operational data streams in order to understand the DSM impacts on energy and demand, as well as to properly model historical relationships. In order to attain an accurate DSM program performance forecast for the future, Hoosier Energy uses a two-part approach. The first part requires estimating a realistic forecast on a short-term base tied to the most recent study completed by an outside consulting firm. This study incorporates data updated with actual DSM performance through the most recently completed year and the addition of new programs. The second part incorporates Hoosier Marketing Department staff meeting with each of the member systems to develop estimated forecasts, making adjustments as needed, and discussion of long-term forecast impacts.

2.4.2 Population and Real Per Capita Income

Externally obtained county level databases for both population and income have been transformed into what is known as “service area” population and income databases. For each member system, this is accomplished by multiplying county-level variables by “county weights”, then summing the result for all counties served by the member. Service area databases are developed for each of the

Hoosier Energy member systems. These databases are established not only for the historical time period in review, but also for the forecast time period.

Use of county weights are necessary because each of the member systems serves only a portion of the respective counties and simply adding the total population or incomes of the served counties would not have been accurate in representing the member system consumers served. The methodology used in the creation of the county weights, along with the defined service area values, has been reviewed and previously used by the State Utility Forecasting Group (SUGF) and the Center for Econometric Model Research (CEMR) established within the Kelley School of Business at Indiana University.

County weights are the share of the county households served by the member system in a specific county. County level household estimates are obtained annually from external agencies. The number of consumers (households) served by the member distribution system in each county is obtained directly from the operating statistics of the system. The county weight for each individual county served by the member system is then established on an annual basis via the ratio of consumers served in a specific county to total consumers in that county. These calculations are performed for each historical year. The weighting in the most recent historical year is held constant and carried forward into the forecast time period.

2.4.3 Weather

Weather is one of the most significant factors in the determination of the variability of electricity sales. Therefore, heating degree-day and cooling degree-day figures are essential variables. A heating degree-day is a unit representing one degree of deviation below 65 degrees Fahrenheit in the mean temperature for one day. Similarly, a cooling degree-day reflects average temperatures above 65 degrees. These degree-day indices provide a measure of how much space heating or air conditioning would have been used over a month.

The weather data used by Hoosier Energy is a weighted average of the readings from the weather stations in the region, with the weights reflecting the average Hoosier Energy population surrounding the weather station. Data on both monthly and annual heating and cooling degree-days for the weather divisions and/or weather stations in Indiana, Kentucky, Illinois and Ohio are published by the National Oceanic and Atmospheric Administration. Weather information is required from the surrounding states since they also border several of Hoosier Energy's service areas.

2.4.4 Fuel Prices

Another important factor affecting the use of electricity is the price of alternative fuels. For example, if the price of fuel oil or LP gas is high, people who are installing new space heating systems (either replacement systems or equipment for new homes) may decide to heat with electricity rather than oil or gas. To capture the potential fuel substitution effects, historical data on fuel prices were collected at the national, regional and state levels. These variables in the past were collected at the specific service area region level within the state; however, these detailed values are no longer available.

The various data on fuel prices are obtained from publications produced by the Energy Information Administration and U.S. Department of Energy. The data in the PRS database included the average prices of:

1. Total energy by residential consumers (primary energy and electricity)
2. Coal
3. Natural gas
4. Petroleum products
5. Distillate fuel
6. Kerosene, liquid petroleum gas, and ethane.

2.4.5 Agricultural Variables

Twelve agricultural variables were collected for the database to reflect the use of electricity on the farms served by the member systems. When possible, these variables were collected at the county level, with estimates developed for the service area using the county weighting procedures. In some instances, where county-level data was unavailable, state-level data was used.

Corn, milk, hay, oats, soybeans, wheat, cattle, beef cattle, milk cattle, chickens, turkeys and hogs represent major agricultural products in southern Indiana and Illinois. Data was collected on these variables from Indiana Agricultural Statistics, compiled by the Indiana Agricultural Statistics Service and from Illinois Agricultural Statistics, compiled by the Illinois Agricultural Statistics Service.

Various procedures are used in the development and analysis of these variables. These procedures include reviewing the variables through a simple sum of production in all counties served by the member systems; a county weighted production number summation representing the service area value; and the variable production magnitudes at the state level. The simple sum of production process involves the adding of the county-level production values incurred across each county for each variable. The county weight process is similar to what was described in the population and income sector of this report. This process involves applying a county weight factor to county-level information in order to develop a number more representative of the true member system service area. In addition to reviewing the number at a county and/or service area level, the variable can also be reviewed at the state level.

Theoretically, if the service area agricultural production is correlated to the state's production trends, these agricultural data are strong proxies for reflecting agricultural activity for the service area. The cost of collecting these state-level variables for the database is also much lower.

2.4.6 Other Variables

Many other variables are available for the database. These variables can provide a basis for possible future extensions of the PRS Energy Model. The Indiana University STATS INDIANA computer network and the Illinois Department of Commerce and Economic Opportunity provide excellent resources in gathering county, state and U.S. economic data. Unemployment rates, number of establishments, personal income, and number of people employed are a few examples of the type of information available to users. Future use of this data will help in understanding the characteristics of the various areas served by the Hoosier Energy member systems.

2.5 Load Shapes and Other Consumption Pattern Databases

2.5.1 Hoosier Energy Customer Databases

Hoosier Energy currently maintains a database of monthly and annual energy sales by customer class. The database was developed for use in the econometric forecast models of the Power Requirements Study and is maintained through the annual collection of member system RUS Form 7s. The customer class breakdowns in the data set are based upon the RUS Form 7 definitions, and are as follows:

1. Residential - includes year-round and seasonal residential.
2. Commercial and Small Industrial - non-residential consumers with transformation less than or equal to 1,000 kVA.
3. Industrial - non-residential consumers with transformation greater than 1,000 kVA.
4. Other - irrigation, public street and highway lighting, and other unclassified sales.

With respect to rate classes and SIC codes, data is not collected either through regulatory forms or metering, and databases of such consumption patterns have not been developed.

2.5.2 Total System Load Shapes

Appendix B contains various load shapes for the total Hoosier Energy system. These include the Hoosier Energy load duration curve, winter and summer peak day load curves, typical winter, summer, spring and fall load curves, for weekdays and weekend days. These load curves are historically based. While Hoosier Energy expects the magnitude of the loads to increase, at this time, Hoosier Energy does not expect the fundamental shape of these curves to change over the planning period.

2.5.3 Disaggregated Load Shapes

Hoosier Energy does not have the resources to disaggregate the historical total system load shape by customer class (i.e., residential, commercial, and industrial) nor by specific end-uses. However, to study the feasibility of economical DSM programs, Hoosier Energy in 1995 undertook a project to develop end-use load shapes. Hoosier Energy, in conjunction with EPRI, focused its efforts on development of 26 specific residential end-uses. These load shapes were developed from end-use metered data and studies obtained from other utilities, along with engineering models. No further activity in this area has taken place within Hoosier Energy. However, work supporting DSM program analysis by outside consultants would most likely contain similar analytical load shape data, along with engineering models.

2.5.4 Future End-Use Surveys

Hoosier Energy has conducted a residential end-use survey typically on a two-year to three-year cycle since 1979. The structure of the survey remains the same as that of the most recent survey, which was strictly an end-use and consumer characteristic survey. This research is conducted to support Hoosier Energy and its 18 member distribution cooperatives in better understanding their consumers' demographics and electricity use, as well as each members' PRS. Prior to 2009, Hoosier Energy had conducted its surveys over the telephone. However, as changing technologies have eroded the representativeness of surveying by telephone only, the survey process has evolved

into a blended effort employing both telephone and internet. This in-turn, assures a more representative and expanded sample.

The residential survey total sample quotas for each of the 18 cooperatives are established such that the number of completed surveys provides for a sampling error of plus or minus 5.0% at the individual cooperative level, hence producing an overall sampling error of plus or minus 1.25% at the Hoosier Energy system level. Both sampling error magnitudes are based upon a 95% confidence level. Each survey provides a snapshot of the residential consumer's appliance saturation and characteristics at a specific time. In addition, through continuous building and maintenance of a survey database such as the one established, historical appliance and consumer characteristic trends can be examined. Through these historical observations that are valid at each individual system level, insight into the development of future appliance and consumer characteristics may be developed, along with processes to better serve and meet the needs of consumers in the distribution system.

2.6 Continuing Model Development

Modeling is a dynamic process. Each modeling exercise is a learning experience, during which possibilities for model reformulations are often uncovered. Each stage of the model development process, from database development to model estimation and validation to model simulation, brings additional insights that can be applied to the next round of development. The modeling process must be approached in terms of continual development, not only to reflect new ideas but also to incorporate changing patterns of electricity use. The estimated coefficients of an econometric model are subject to obsolescence because of periodic structural change. The values of the estimated coefficients of the independent variables are dependent upon a number of factors. Many of these factors, such as people's attitudes, beliefs, habits and perceptions are intangible, while others are tangible. All of these factors and relationships implicitly must be captured via all of the coefficients built within the model. When it becomes apparent that the variable relationships have changed significantly, causing the model to no longer adequately track electricity sales, the econometric models must be re-estimated. In order to identify when it is necessary to re-estimate the model, model performance must be continuously monitored.

The most direct strategy for monitoring model performance is to compare the predicted with actual electricity sales when new data is available. There are two possible sources of error in the forecasts. One source is inherent in the model itself, if the model specification is incorrect or if it is outdated. The actual values of the input variables will be used to run a model simulation and the predicted values will be compared with the actual. If the model predictions are considerably different from actual sales and consumers when actual historical inputs are used, a re-estimation of the model with an updated database may be warranted. Another source of error is in the predicted values of the input variables. If input projections are unrealistic, the model results based on these inputs will be unrealistic. Therefore, the model may produce relatively accurate forecasts only when the projected input values are themselves accurately reflecting future patterns.

A second procedure for monitoring model performance is to collect updated information on the projections of the input variables to the models. As time passes, organizations such as Moody's Analytics, Woods and Poole Economics, the Bureau of Economic Analysis, etc., will be publishing updated projections of population and real per capita income. These new forecasts will be incorporated into new scenarios to update the forecasts of electricity sales. Model results must be evaluated in terms of change in the system that might affect how the variables of the models

interrelate. There must be a periodic assessment of the impact of system-wide changes such as DSM program positioning or rate structure modifications. These changes may affect model reliability and require an adjustment to the forecasts derived from the model. Indirect and direct consideration of items such as these have been taken into account in this forecast through the exchange of ideas and information with the member system PRS representatives and managers.

As with all econometric models, the Residential Submodel equations will need to be re-estimated to incorporate new data as it becomes available. This process will involve updating the database and exploring the need to include additional variables to reflect changes in average residential use and the number of consumers. Methodologies of incorporating the initial and long-term impact of demand side management programs on energy and demand levels will also be reviewed in the model review process. Because of a lack of information in the past, the impacts of these types of programs were analyzed only at the Hoosier Energy system level. Since 2011, they were incorporated into the member system forecasts to produce final forecasts with DSM. There will be continued dialogue between the member systems and Hoosier Energy to ensure that the PRS review, data development and revisions reflect a consensus.

The approach chosen in the PRS is one of many forecast methodologies used by electric utilities. As the electric market becomes more competitive, new DSM programs are introduced, along with the structure of the market being altered; methodologies on how to incorporate these effects of these programs into existing and/or new modeling techniques for all classifications must be explored. There will be continuing evaluation of possible alternative methodologies to be used in forecasting energy and demand values.

2.7 Load Forecast

Hoosier Energy's forecasted peak demand and energy for the period from 2018 through 2037 are displayed in Table 4 below. For purposes of this IRP, Hoosier Energy has decided to use the Base-Upper Normal weather scenario as its base case. The demand and energy forecasts provided by the Base-Upper Normal scenario deliver the best fit when compared to Hoosier Energy's 2016 actual load. The forecasted compound average growth rate for both demand and energy in the Base-Upper Normal scenario is approximately 0.7% for the period. Table 5 displays Hoosier Energy's forecasted energy requirements by customer class, while Table 6 presents the forecasted annual peak demand and energy forecast for the base case, high load growth scenario and low load growth scenario.

Base Upper Normal Scenario including DSM (at Generation)¹						
	Winter Peak Demand (MW)	Winter Peak Growth (%)	Summer Peak Demand (MW)	Summer Peak Growth (%)	Annual Energy (MWh)	Annual Energy Growth (%)
2018	1,539		1,478		7,874,114	
2019	1,556	1.1%	1,497	1.3%	7,965,782	1.2%
2020	1,571	1.0%	1,516	1.3%	8,041,589	1.0%
2021	1,584	0.8%	1,533	1.1%	8,113,523	0.9%
2022	1,591	0.4%	1,553	1.3%	8,169,523	0.7%
2023	1,600	0.6%	1,581	1.8%	8,223,903	0.7%
2024	1,610	0.6%	1,593	0.8%	8,281,293	0.7%
2025	1,619	0.6%	1,606	0.8%	8,340,335	0.7%
2026	1,629	0.6%	1,620	0.9%	8,400,830	0.7%
2027	1,640	0.7%	1,632	0.7%	8,457,571	0.7%
2028	1,653	0.8%	1,646	0.9%	8,520,984	0.7%
2029	1,666	0.8%	1,659	0.8%	8,583,315	0.7%
2030	1,678	0.7%	1,673	0.8%	8,646,091	0.7%
2031	1,690	0.7%	1,687	0.8%	8,708,837	0.7%
2032	1,704	0.8%	1,701	0.8%	8,775,978	0.8%
2033	1,708	0.2%	1,706	0.3%	8,793,464	0.2%
2034	1,716	0.5%	1,715	0.5%	8,828,191	0.4%
2035	1,723	0.4%	1,723	0.5%	8,865,949	0.4%
2036	1,737	0.8%	1,738	0.9%	8,941,953	0.9%
2037	1,747	0.6%	1,748	0.6%	8,995,605	0.6%
CAGR %		0.7%		0.9%		0.7%

1 - Energy forecasts include forecasted Demand Side Management/Energy Efficiency impacts.
Source: Hoosier Energy's 2017 PRS and 2018 - 2022 Business Plan

Table 4: Forecasted Demand and Energy Requirements

Breakdown of Forecasted Energy Requirements by Customer Class (MWh)¹

Year	Residential	Commercial	Industrial	Other	Distribution		Total Energy Requirements
					System Losses	Transmission System Losses	
2018	4,223,295	979,893	1,975,561	38,923	325,729	330,713	7,874,114
2019	4,266,182	992,823	2,003,596	38,923	329,695	334,563	7,965,782
2020	4,308,852	1,006,520	2,016,693	38,923	332,854	337,747	8,041,589
2021	4,347,589	1,016,755	2,033,668	38,923	335,820	340,768	8,113,523
2022	4,384,634	1,025,878	2,038,772	38,923	338,196	343,120	8,169,523
2023	4,419,482	1,034,960	2,044,637	38,923	340,497	345,404	8,223,903
2024	4,455,192	1,045,356	2,051,122	38,923	342,886	347,814	8,281,293
2025	4,489,119	1,059,188	2,057,433	38,923	345,378	350,294	8,340,335
2026	4,526,742	1,071,223	2,063,187	38,923	347,920	352,835	8,400,830
2027	4,566,215	1,086,911	2,060,482	38,923	349,822	355,218	8,457,571
2028	4,608,528	1,102,662	2,060,482	38,923	352,508	357,881	8,520,984
2029	4,649,772	1,118,478	2,060,482	38,923	355,161	360,499	8,583,315
2030	4,691,361	1,134,358	2,060,482	38,923	357,831	363,136	8,646,091
2031	4,732,853	1,150,303	2,060,482	38,923	360,505	365,771	8,708,837
2032	4,778,073	1,166,551	2,060,482	38,923	363,357	368,592	8,775,978
2033	4,824,768	1,182,864	2,013,044	38,923	364,539	369,326	8,793,464
2034	4,875,434	1,199,242	1,977,466	38,923	366,342	370,784	8,828,191
2035	4,928,776	1,215,689	1,941,888	38,923	368,304	372,369	8,865,949
2036	4,981,800	1,232,201	1,941,888	38,923	371,579	375,562	8,941,953
2037	5,011,691	1,239,594	1,941,888	38,923	385,693	377,815	8,995,605

1 - Energy forecasts include forecasted Demand Side Management/Energy Efficiency impacts.

Table 5: Forecasted Energy Requirements by Customer Class

Summary of Forecasted Demand and Energy Requirements¹
Base-Upper Normal Scenario, High Economic Scenario and Low Economic Scenario

Year	Summer Peak Demand - Annual Energy Base-Upper Requirements -		Summer Peak Demand - High Annual Energy Economic Requirements -		Summer Peak Demand - Low Annual Energy Economic Requirements -	
	Normal Case	Base Case	Scenario	High Load	Scenario	Low Load
2018	1,478	7,874,114	1,508	7,981,410	1,393	7,337,406
2019	1,497	7,965,782	1,535	8,115,398	1,401	7,371,402
2020	1,516	8,041,589	1,562	8,239,202	1,409	7,391,707
2021	1,533	8,113,523	1,589	8,362,684	1,416	7,409,372
2022	1,553	8,169,523	1,625	8,472,780	1,430	7,411,503
2023	1,581	8,223,903	1,648	8,583,181	1,432	7,412,120
2024	1,593	8,281,293	1,672	8,698,331	1,434	7,415,443
2025	1,606	8,340,335	1,696	8,816,556	1,437	7,420,234
2026	1,620	8,400,830	1,721	8,937,826	1,440	7,425,759
2027	1,632	8,457,571	1,745	9,056,631	1,442	7,427,288
2028	1,646	8,520,984	1,771	9,183,572	1,445	7,434,859
2029	1,659	8,583,315	1,797	9,310,803	1,447	7,440,904
2030	1,673	8,646,091	1,823	9,439,958	1,450	7,446,775
2031	1,687	8,708,837	1,850	9,570,411	1,453	7,452,229
2032	1,701	8,775,978	1,878	9,707,026	1,456	7,461,076
2033	1,706	8,793,464	1,897	9,795,737	1,450	7,419,395
2034	1,715	8,828,191	1,919	9,903,364	1,447	7,394,129
2035	1,723	8,865,949	1,942	10,015,541	1,444	7,371,323
2036	1,738	8,941,953	1,971	10,167,517	1,447	7,386,227
2037	1,748	8,995,605	2,001	10,320,030	1,450	7,400,999

1 - Demand and Energy forecasts include forecasted Demand Side Management/Energy Efficiency impacts.

Table 6: Summary of Forecasted Demand and Energy Requirements

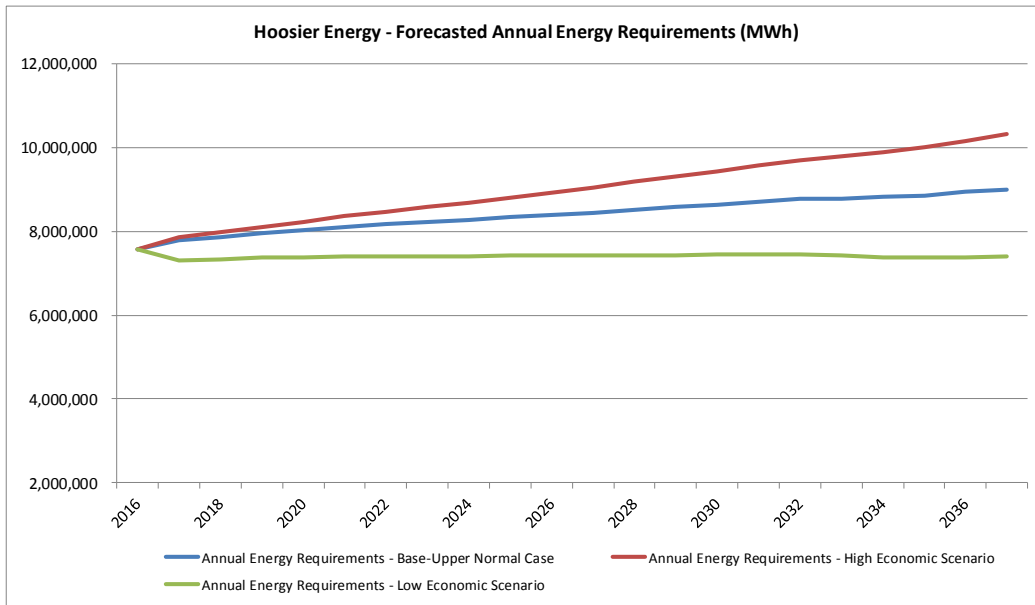


Table 7: Forecasted Annual Energy Requirements (includes DSM impacts)

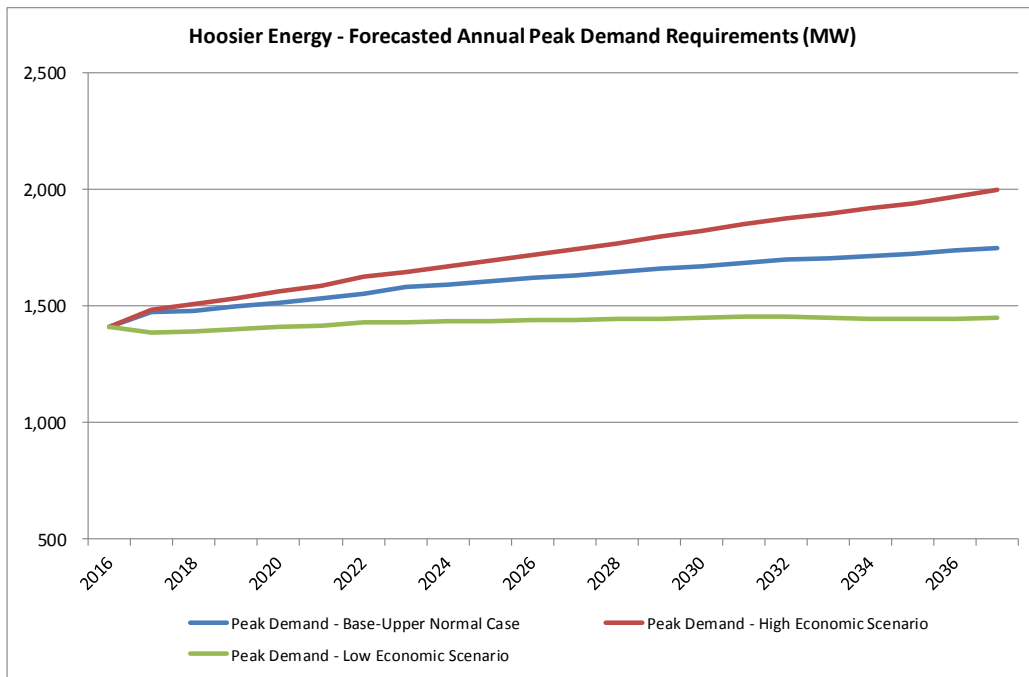


Table 8: Forecasted Annual Peak Demand Requirements (includes DSM impacts)

Section 3: Resource Assessment

3 Resource Assessment

As required by 170 IAC 4-7-6, Section 3 of this IRP describes Hoosier Energy's existing resources, including generation, transmission, rate design and demand-side management. Future Resource Assessments are presented in Section 4 of this IRP.

The 2017 Hoosier Energy Integrated Resource Plan was developed to enable Hoosier Energy to seek the lowest power supply cost possible for member distribution systems for a targeted level of low market and business risk, while maintaining a high degree of generation and transmission reliability. Through this IRP, Hoosier Energy has attempted to include all economic and reliable resources, both traditional supply-side resources and demand-side resources, to meet future electric service requirements.

3.1 Existing Resource Assessment

Since 2007, Hoosier Energy has made a number of changes to its resource portfolio demonstrating a commitment to an "all of the above" power supply strategy. Hoosier Energy has added resources fueled by natural gas, landfill gas, wind, solar, hydro as well as continued energy efficiency and demand response efforts.

- Acquisition of 50% ownership interest in the Holland combined-cycle generation facility.
- Implementation and update of new wholesale tariff options to support demand response efforts.
- Completion of an extensive analysis of member consumer energy usage to develop and implement appropriate energy efficiency and demand-side management programs.
- Purchase of 25 MW of wind generation from the Story County Wind Farm in central Iowa through a PPA.
- Purchase of 3.6 MW of generation from Dayton Hydro facility in Dayton, IL through a PPA.
- Purchase of the 15 MW Livingston Renewable Energy Plant in Pontiac, IL
- Purchase of 25 MW of wind generation from the Rail Splitter Wind Farm in central Illinois through a PPA.
- Development of a 10 MW regional solar program throughout southern Indiana.
- Purchase of 75 MW of wind generation from the Meadow Lake Wind Farm in White County, Indiana through a PPA beginning in 2018.
- Pending purchase of 200 MW of solar generation through a PPA beginning in 2020.

The above resource changes have continued the diversification of Hoosier Energy's resource mix with the goal of maintaining reliable and affordable energy for consumers.

3.1.1 Generation Facilities – Owned Resources

Hoosier Energy operates generating stations with a total summer production capacity of approximately 1,760 MW. This capacity consists of 1,070 MW of coal-fired capacity, 665 MW of natural gas-fired capacity and 30 MW of renewable resource capacity.

The Merom Generating Station is a two-unit, coal-fired steam generating facility located in Sullivan County. Unit One became operational in 1983 and Unit Two became operational in 1982. The plant is equipped with electrostatic precipitators for fly ash removal, a flue gas desulfurization system, or scrubber, to remove sulfur dioxide, selective catalytic reduction technology to remove nitrogen oxide and SBS technology to control SO₃ (acid aerosol) emissions. Mercury control systems were added in 2015. Except for those prospective changes required by more stringent environmental restrictions, Hoosier Energy has not included any planned changes to this facility in the IRP analysis.

The Worthington facility consists of four General Electric LM6000s with a net summer demonstrated capacity of 169 MW. Worthington is directly interconnected to the Hoosier Energy transmission system. The LM6000 combustion turbines are more efficient than “frame-type” combustion turbines with a heat rate of approximately 10,000 Btu per kWh. LM6000s also have quick start capability and their relatively small individual size allows significant scheduling and ramping flexibility.

The Lawrence generation facility became operational in May of 2005. Lawrence consists of six General Electric LM6000s combustion turbines with a net summer capacity rating of 264 MW. Hoosier Energy owns two-thirds of the facility and the output while Wabash Valley Power Association owns one-third. The CTs have a heat rate of approximately 10,000 Btu per kWh and have quick start capability.

In January of 2009, Hoosier Energy took possession of 50% ownership interest in the Holland generation facility. Holland is a gas-fired, combined cycle facility located in Effingham County, Illinois. Holland is a 2x1 CC with two GE 7FA combustion turbine generators and a single Toshiba steam turbine generator. The facility is also equipped with two Nooter/Eriksen Heat Recovery Steam Generators with NO_x selective catalytic reduction (SCR) and 75 MW duct burners for each HRSG. Total plant heat rate is approximately 7,500 Btu per kWh. In 2016, Hoosier Energy’s Board approved gas turbine compressor upgrades for both Holland Units 1 and 2. This work will be performed during 2017 and 2018 outages. The compressor upgrades improve blade damage tolerance, reduce inspection requirements and increase reliability and availability.

Clark-Floyd generating station is a baseload, landfill methane gas-fired facility. This project was commissioned in October 2007 as a 2 MW project. Capacity was increased in June of 2009 to 3.5 MW. The sole source of fuel for the project is methane gas collected from the Clark-Floyd Landfill in southern Indiana.

The 15 MW Livingston Renewable Energy Plant, located near Pontiac, Illinois, is a baseload, landfill methane-gas facility. This facility was acquired by Hoosier Energy in November 2011 and has been refurbished and began operations in October 2013. The plant consists of three turbine engines fueled by landfill methane gas, which is sourced from the 460-acre Livingston Landfill. Energy from the Livingston plant is delivered to the grid through an interconnection with ComEd.

The 16-megawatt Orchard Hills facility near Rockford, Illinois will be Hoosier Energy’s third landfill gas generation facility. This resource is projected to begin operating in 2018.

Beginning in 2015, Hoosier Energy commenced a 10 MW regional solar program. The program consists of construction and operation of ten different 1 megawatt solar arrays located along highly visible roadways across southern Indiana. Each array provides benefits for both the nearby local cooperatives as well as all 18 member systems. The cost for generating solar power through a utility-scale program is significantly less per kilowatt hour when compared with individual, smaller scale systems. Collectively, the ten solar sites will provide approximately 20,000 MWh of energy annually for the 300,000 homes, businesses and farms served by Hoosier Energy’s 18-member distribution cooperatives.

Hoosier Energy’s Osprey Point Renewable Energy Station began operations in May 2013. Osprey Point is a 13 MW unit located on the Merom station grounds in Sullivan County. Osprey Point consists of four reciprocating engines, which are fueled by coal bed methane (CBM) gas collected through an underground collection system linking several CBM wells on the Merom property. In 2016, operations at the Osprey Point station were suspended. Therefore, Osprey Point’s capacity is not included in the calculation of active resources. Currently, Hoosier Energy is studying the feasibility of serving the units from an alternative fuel supply in order to increase unit generation levels.

Table 9 summarizes Hoosier Energy’s owned generation facilities.

Resource	Type	Nameplate Capacity (MW)	Net Demonstrated Capacity (MW)	ISO/RTO Unforced Capacity (MW)
Merom 1	Coal	535	501	455
Merom 2	Coal	535	482	438
Holland	Gas	315	307	301
Worthington	Gas	174	169	163
Lawrence	Gas	176	175	166
Clark-Floyd	Landfill Gas	4	4	4
Livingston	Landfill Gas	15	13	11
Orchard Hills	Landfill Gas	16	16	14
Solar Units	Solar	10	10	5

Table 9: Hoosier Energy's Owned Generation Summary

3.1.2 Power Purchases

In addition to owned generation resources, Hoosier Energy uses a mix of long-term and short-term power purchases to provide reliable and least-cost service to member systems.

Hoosier Energy purchases 150 MW from Duke Energy Indiana under two separate, cost-based, long-term purchase agreements. The first agreement is for 100 MW and runs through 2023, while the second agreement is for 50 MW and runs through 2025. Both agreements contain load factor requirements that qualify them as baseload generation resources. These purchases provide better diversity and less operating risk characteristics than an owned resource.

Hoosier Energy also purchases capacity, energy and renewable energy credits from renewable resources through a number of purchased power agreements. Renewable generation includes wind, hydro, solar and biomass facilities that do not rely on traditional fossil fuels.

The Story County wind project is a 150 MW wind farm developed by FPL Energy, which became operational in November of 2008. Hoosier Energy has rights to 25 MW through a 10-year agreement for energy, capacity, and renewable energy credits. Hoosier Energy is participating in conjunction with other cooperatives with coordination provided by ACES.

A 20-year purchased power agreement was finalized in 2012 for electricity produced by the Dayton Hydro facility. This project is a 3.6 MW hydroelectric facility near Dayton, IL. The plant produces about 18,000 megawatt-hours annually, enough to power about 1,500 homes.

The Rail Splitter facility is a 100 MW merchant facility built in 2009 and located near Lincoln, Illinois. In 2014, Hoosier Energy entered into a 15-year agreement with EDP Renewables to purchase 25 MW from the facility. Energy purchases under the PPA began in December 2014 and continue through the end of 2029. In addition to capacity and renewable energy credits, Hoosier Energy receives approximately 70,000 MWh of energy annually from the facility.

In November 2015, Hoosier Energy's Board approved a PPA with developer EDP on a wind project in White County in northwest Indiana. The PPA includes the purchase of 75 MW from the Meadow Lake V project. The Meadow Lake V project represents an expansion of the existing 500 MW wind farm that has been in service for a number of years. Hoosier Energy will purchase 25 MW starting in January 2018 for a 20-year term and an additional 50 MW beginning in January 2020 for a 20-year term. A 38% capacity factor is anticipated.

In November 2017, Hoosier Energy's Board approved a Resolution authorizing a long term PPA for energy and capacity from a 200 MW solar array. The array will be built in Hoosier Energy's service territory and interconnected to the PJM regional transmission organization. The PPA calls for 100 MW and 205,000 MWh annually beginning January 1, 2020 with an additional 100MW and 205,000 MWh beginning January 1, 2021. The 20-year PPA extends through December 31, 2039. The energy price is fixed throughout the term. In addition, Hoosier Energy will receive Renewable Energy Credits (RECs) as part of this transaction. No capital investment will be required by Hoosier Energy. The agreement also protects Hoosier Energy from exposure to negative LMP prices and includes provisions guaranteeing delivery of 75% of expected annual energy from the array. However, the possibility of a federal tariff on imported solar panels could jeopardize the PPA.

Table 10 summarizes Hoosier Energy's existing contracted power purchases.

Resource	Type	Expires	Contracted Capacity (MW)	ISO/RTO Unforced Capacity (MW)
Duke Indiana	Slice of System	2023	100	100
Duke Indiana	Slice of System	2025	50	50
Story County	Wind	2019	25	0
Dayton Hydro	Hydro	2031	4	2
Rail Splitter	Wind	2029	25	4
Meadow Lake	Wind	2037	25	4
Meadow Lake	Wind	2039	50	8
Solar PPA *	Solar	2039	100	19
Solar PPA *	Solar	2039	100	19

* - pending

Table 10: Hoosier Energy's Power Purchases Summary

3.2 Demand-Side Resource Assessment

DSM is generally defined as utility action or policy that reduces energy consumption or curtails end-use equipment or processes. DSM includes programs that are focused and immediate such as the brief curtailment of energy-intensive processes (demand response). In addition, DSM includes programs that are broad and less immediate such as the promotion of energy-efficient lighting, equipment and devices.

3.2.1 DSM Programs

Hoosier Energy and its member distribution cooperatives have developed a number of demand response and energy efficiency programs. Appendix F is the 2016 Demand Side Management Annual Report, which provides detail on the impact by member system. The Annual Report also provides demand and energy savings and economic benefit projections by program.

Hoosier Energy has developed a website to provide member consumers with online access to information on each of the available DSM programs, including how to sign up for each program.

Member consumers can also purchase energy-efficient lighting through the website. A link to Hoosier Energy's DSM website is below.

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TEAM UP
Together We Save.

Providing winning ways for you to save energy and money with the help of your local electric cooperative!

WELCOME TO TEAM UP!

By participating in one or more of the energy-saving programs listed below, you can become an MVP when it comes to energy efficiency. As an added bonus, when we work together to use electricity wisely, we help keep the cost of power stable and affordable for everyone. When we Team Up, we all win!

Check out the All-Star Lineup of programs below to see how you and your local electric cooperative can team up for a winning game plan.

Check out our online lighting store discounts and rebates.

Source: <http://teamuptosave.com>

3.2.1.1 Residential Lighting Program

Retail cooperative members have access to high quality, energy efficient light emitting diode (LED) products through an online store. Lamps come with an instant rebate and free shipping to make it more affordable to replace inefficient lighting with long lasting, low wattage LEDs. The online store also offers easy, self-install products such as weather stripping, outlet and wall switch gaskets, LED nightlights, and refrigerator/freezer thermometers at low cost and with free shipping.

Agricultural and smaller commercial consumers can also benefit from cooperative membership with additional pricing discounts for bulk quantities ordered through the online store. In 2016, more than 90,000 high-efficiency lamps were ordered through the cooperative online store increasing the overall total to more than 1.7 million lights since the program began in 2009.

3.2.1.2 LED Security Lighting

By using LED models to replace older and more maintenance intensive mercury vapor or high-pressure sodium security lights, cooperative members can reduce energy requirements for those fixtures by as much as 70 percent. Nearly 6,000 security lights were replaced with high-efficiency dusk-to-dawn LED fixtures in 2016.

3.2.1.3 Residential HVAC Rebates

The residential heating, ventilation and air conditioning (HVAC) program provides incentives to homeowners to upgrade to more efficient systems. More than 4,300 HVAC, attic insulation and duct sealing rebates were paid in 2016 to consumers who installed qualifying equipment. The number of geothermal heat pump rebates increased slightly from prior years, likely in anticipation of expiration of a 30% income tax credit for equipment placed in service by the end of 2016. Dual fuel heat pump rebates showed 29% percent growth in 2016 while air source heat pumps and heat pump water heaters experienced steady installation rates. Cooperative rebates for geothermal systems continue but fewer new systems are expected as a result of termination of the tax credit.

3.2.1.4 Attic Insulation and HVAC Duct Sealing

Rebates for duct sealing and attic insulation jumped dramatically in 2016 with 1,901 installations. Difficulties attracting qualified contractors in several areas and related quality control concerns presented significant challenges that contributed to a decision to eliminate these programs in future years.

3.2.1.5 Commercial and Industrial Programs

Commercial and Industrial (C&I) and Direct Install program incentives help make changing to high-efficiency lighting, motors and other equipment easier and more affordable for business owners and managers. The C&I program showed continued strong growth in 2016 with 242 completed rebates for lighting, HVAC, motor and compressed air systems and \$1,284,723 paid for incentives. Those incentives leveraged an additional \$6 million in efficiency investments by C&I facility owners. Program results are projected to reduce lifetime energy costs for participating businesses by more than \$49 million.

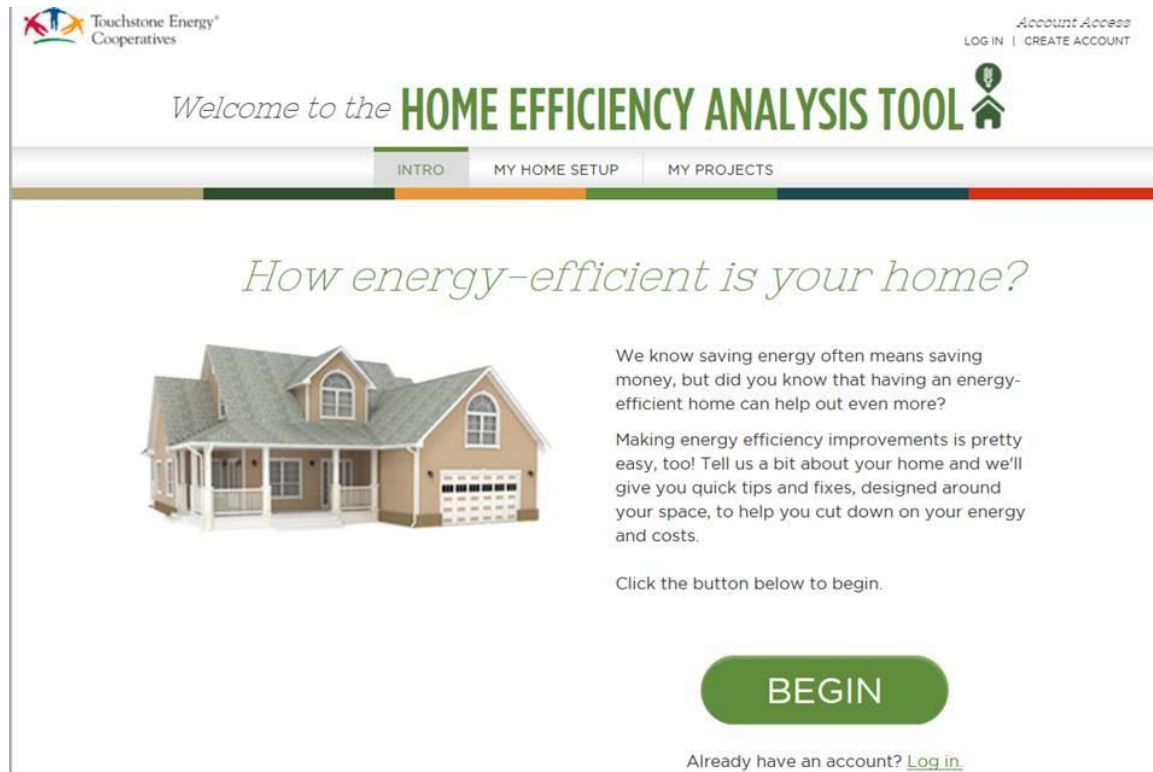
3.2.1.6 Energy Management Savings Switch Program

In conjunction with Member Systems, an energy management switch program is offered. This load control or demand response program is designed to alleviate demand increases by briefly cycling the retail customer's air conditioners, water heaters, pool pumps and irrigation systems. Activation of switches during peak demand periods by Hoosier Energy helps reduce the need for more expensive generation or purchased power. Member System participation is encouraged through price signals from the Standard Wholesale Tariff and Member Systems may also provide incentives to retail customers through bill credits or rebates. All Member Systems have installed advanced metering infrastructure or AMI and some use this to technology to implement this program.

3.2.1.7 Home Efficiency Analysis Tool

Hoosier Energy, through its association with Touchstone Energy, provides access to an online Home Efficiency Analysis Tool, which is an interactive website providing member consumers with information that will allow them to reduce residential energy usage. Consumers are prompted for

information such as home type, location, size, age and number of occupants. In response, the tool will provide suggestions on the types of projects that can be done in each area of the home to reduce energy usage and costs. A screen shot of the Home Efficiency Analysis Tool homepage is displayed below.



Source: <http://homeefficiency.touchstoneenergy.com>

3.2.2 Wholesale Tariffs

In April of 2010, Hoosier Energy implemented new wholesale tariffs designed to encourage demand response participation by the member systems and to introduce time-of-use energy pricing. The tariffs were reviewed and rates updated by Hoosier Energy in 2017 for implementation in April 2019. Below is a description of the Standard Wholesale Tariff:

Production Demand Charge - To support residential control programs, the Standard Wholesale Tariff aligns the G&T tariff and system capacity costs through higher seasonal demand charges that more accurately reflect the greater cost of capacity in summer and winter peak months. Production Demand charges are billed on the Hoosier Energy coincident peak at the time of a load control event in the peak summer months of June, July and August and the peak winter months of December, January and February. The off-peak months of September – November are billed on the average coincident peak for the three previous summer months. Similarly, the off-peak months of March – May are billed on the average coincident peak for the three previous winter months. This better ensures that the members are able to earn a return on their load control investment. The Standard Wholesale Tariff supports load control by reducing the number of months in which load must be

controlled to achieve savings, increases the number of months in which members benefit from peak load reductions, restricts control to months when reductions will most likely produce system benefits, mitigates impacts on consumers, and provides additional protection from cost shifting to members that don't participate in load control programs.

Although not explicitly referenced in the new Standard Wholesale Tariff, the proposed load control program is controlled by Hoosier Energy. Control criteria is primarily based upon reduction in Hoosier Energy system peaks demands, but load control will also be operated for purposes of emergency demand response within MISO. Load control protocols also consider the impact on consumer satisfaction.

Transmission Demand Charge – The charges are based upon system coincident demand (CP) or the 60-minute clock hour during the month between 7:00 a.m. and 11:00 p.m. (EST) in which total system demand reaches its highest point. The transmission charge recovers costs associated with system-wide transmission facilities and MISO costs.

Substation/Radial Line Demand Charge – Billed on the non-coincident peak (NCP) for a 30-minute clock interval, this charge recovers the substation and local line costs for each meter point.

Energy Charge - The Standard Wholesale Tariff includes both on-peak and off-peak energy charges, with the on-peak charges set higher than the off-peak energy charges. On-peak periods for energy charges are narrowly defined as including six hours per day on summer weekdays and two, three-hour periods on winter weekdays. All weekend days and all days in “valley” months of March through May and September through November are defined as off-peak for energy charges. The differentiation between on and off-peak energy charges is intended to recover energy costs in a manner more consistent with the market price signals. In addition, this differentiation provides an incentive to members and end consumers to shift load to off-peak periods.

Optional Wholesale Tariffs

Hoosier Energy offers wholesale tariffs that are intended to provide consumers with options to manage energy costs. The tariffs are also designed to provide the G&T with tools to better manage costs during periods of high demand and market prices and to promote consumer-owned distributed generation, including the purchase of consumer power by Hoosier Energy. While not required by the Energy Policy Act of 2005, the provisions of these tariffs are consistent with key principles of that legislation. The tariffs reflect the G&T's continuing effort to develop efficiency and demand response/demand-side management (DSM) options for consumers. Tariff provisions are summarized below.

Interruptible Power Tariff No. 2

- 500 kW minimum demand and 500 kW minimum interruptible demand
- Customer contracts for “firm” load; remainder subject to interruption
- No buy-through provision
- Interrupt from 7:00 to 11:00 p.m. daily, 1-hour notice, 500 hours per year

Schedule CPP – Avoided Rates for Qualifying Facilities and Distributed Generation Resources

- Customer-owned power production resources between 50 kW and 20,000 kW

- Purchases from Qualifying Facilities paid in accordance with formulae are found at 170 IAC 4-4.1-8 and 4-4.1-9.
- Purchases from Distributed Generation resources shall be negotiated on a case-by-case basis but shall not exceed the rates for purchases of energy and capacity from Qualifying Facilities.

Voluntary Curtailment Rider

- Available to IPT and Industrial Power Transmission Service customers; annual enrollment
- Customer voluntarily agrees to curtail or reduce demand upon request
- Proposed levels are \$0.10, \$0.15 and \$0.25 per kWh
- One hour notice for up to 12 hours of curtailment
- No penalties for non-participation

Standby Service Rider to Industrial Power Tariff (IPT)

- Service option and rates for back-up, supplemental, or standby service
- Requires minimum annual contract demand

3.3 Significant Issues Affecting Resources

3.3.1 Environmental Factors

Environmental Rules and Regulations

In recent years, the U.S. Environmental Protection Agency (EPA) has issued numerous regulations intended to reduce harmful air emissions and wastewater contaminants. Due to challenges from the past and current Administration, the potential impact and timing of these regulations to Hoosier Energy remains unclear in some instances. However, coal generation continues to be a target for new rules and tightening regulations.

Effluent Limitations Guidelines

On November 3, 2015, EPA published the Final Rule for technology-based effluent limitations guidelines and standards (ELGs) to strengthen controls on water discharges from steam electric power plants. The rule established new or additional requirements for wastewater streams from steam electric power plants utilizing coal or other fossil-type fuel. The rule applies to waste streams at coal fired electrical power plants associated with: FGD, fly ash transport, bottom ash transport, combustion residual leachate, and flue gas mercury controls. Compliance costs associated with the ELG rule have been estimated nationwide to cost \$480 million per year.

On March 24, 2017, and April 5, 2017, respectively, the Utility Water Action Group and U.S. Small Business Administration petitioned the EPA to reconsider and administratively stay future deadlines of the final rule. The petitions raise various challenges to the final rule and argue that the new ELGs are not technologically or economically feasible within the proscribed timeframe, which requires compliance as early as November 1, 2018. Subsequently, on April 12, 2017, the EPA announced that it will reconsider and administratively stay future deadlines of the final rule. Hoosier Energy will need to invest \$46 million to comply with the bottom ash transport and FGD wastewater sections of the rule. Hoosier Energy submitted a request to IDEM for an alternative applicability date of December 31, 2023 and received approval from IDEM for the alternative applicability date on February 20, 2018.

Cooling Water Intake Structures – Clean Water Act 316 (b) rule

Section 316(b) of the Clean Water Act requires EPA to issue regulations on the design and operation of intake structures, in order to minimize adverse environmental impacts. On May 19, 2014, the EPA issued its final rule which applies to facilities that each withdraw at least two million gallons per day of cooling water from waters of the U.S. The rule, which will be administered through National Pollutant Discharge Elimination System (NPDES) permits, requires that existing facilities that withdraw at least 25% of their water from an adjacent waterbody exclusively for cooling purposes reduce fish impingement. The final rule also requires that existing facilities that withdraw more than 125 million gallons per day of water conduct studies to help their permitting authority determine whether and what site-specific controls, if any, would be required to reduce the number of aquatic organisms affected by cooling water systems. Hoosier Energy is currently analyzing its compliance options to this rule. Hoosier Energy was required to submit partial study data in 2017 to IDEM for review. Hoosier Energy is required to submit the remainder of the data in 2018. Currently, there is \$3 million in the project work plan for any potential intake traveling water screen upgrades such as fine mesh cloth. Until IDEM completes their review of all the study data, it is unknown at this time what will be needed for compliance.

Solid Waste Disposal

Annually, Hoosier Energy files Form EIA 923 with the United States Department of Energy Information Administration. On page 2 of Form 923, the Coal Combustion By-Products (CCBP) quantities generated for the year are listed. The quantity of CCBP generated in a given year is a function of the amount of coal burned and its quality.

2016 Data	Merom
Fly Ash Generated (Tons)	219,700
Bottom Ash Generated (Tons)	24,100
FGD Sludge Generated (Tons)	437,700
Stabilizing Additive Used	0
Total CCBP (Tons)	681,500

Table 11: Hoosier Energy By-Products Summary

The majority of CCBP is disposed of in the onsite landfill, which is regulated by IDEM. However, due to increasing market demand for CCBP, approximately 20% is now sold and that percentage is expected to increase in the future. The current active disposal area, as designed, is capable of providing volumetric capacity for 16 years of station operation without consideration of CCBP, but could last longer depending on CCBP sales volume going forward.

The most significant environmental effect associated with onsite disposal of CCBP is the potential for groundwater contamination. This risk is mitigated through engineering controls including low density polyethylene liners for existing and new landfill cells, and a groundwater-monitoring

program which has been in service for over 30 years. The groundwater-monitoring program will remain in service for a prescribed period defined in the solid waste permit after disposal of CCBP is discontinued. Thus far, there has been no indication of off-site groundwater contamination.

NOX Emission Reduction Requirements under CSAPR

On September 7, 2016, the EPA finalized an update to the Cross-State Air Pollution Rule (CSAPR) ozone season program by issuing the CSAPR Update. This rule addresses the summertime (May – September) transport of ozone pollution in the eastern United States that crosses state lines to help downwind states and communities meet and maintain the 2008 ozone national ambient air quality standard (NAAQS). Starting in May 2017, this final rule will further reduce ozone season emissions of nitrogen oxides (NOX) from power plants in 22 states in the eastern United States, including Indiana. According to the agency, the rule could cost an estimated \$68 million, a figure that will be likely disputed by industry.

Essentially, the new CSAPR rule adopts federal implementation plans (FIPs) for all 22 states, updating the existing CSAPR NOx ozone season emission budgets for each state’s power generating units. The EPA said it will implement these budgets through the existing CSAPR NOx ozone season allowance trading program. States will be allowed to replace the FIPs starting in 2018 by submitting state plans that adopt the CSAPR update trading program budgets. Hoosier Energy must maintain the selective catalytic reduction systems in order to comply. Approximately \$4 million annually is needed for NOx control. That cost does not include all of the operation and maintenance expenses associated with that control equipment.

Ozone National Ambient Air Quality Standards

The National Ambient Air Quality Standard (NAAQS) for ground-level ozone is an outdoor air regulation established by the U.S. Environmental Protection Agency (EPA) under the Clean Air Act. Ground-level ozone is a gas that occurs both naturally and forms due to chemical reactions between nitrogen oxides and volatile organic compounds, which are emitted from industrial facilities, power plants, vehicle exhaust, and chemical solvents.

In November 2014, the EPA proposed lowering the ozone standard from 75 parts per billion (ppb) to a range between 65 to 70. During the public comment period for the proposed rule, the Chamber, along with a wide range of industry groups, state and local chambers, state governments, and members of Congress, urged the EPA to retain the current 75 ppb standard. On October 1, 2015, under a court-ordered deadline, the EPA finalized the ozone NAAQS standard at 70 ppb.

On December 23, 2015, the U.S. Chamber of Commerce, joined by eight other business groups, filed a petition for review in the U.S. Court of Appeals for the D.C. Circuit challenging the EPA's rule lowering the ozone standard. On October 26, 2015, five states filed a lawsuit challenging EPA's new 70 ppb ozone standard. Additional states subsequently filed challenges to the standard, including Utah, Wisconsin, Kentucky, and Texas. On April 11, 2017, the D.C. Circuit Court of Appeals granted EPA’s motion to indefinitely stay a lawsuit over the 2015 ozone standard in order to provide the agency more time to review the rule. The EPA is required to file 90-day interval status reports to the court on the progress of its review.

Clean Air Act 111 (d) Existing Plant Rulemaking

On August 3, 2015 President Obama announced EPA's issuance of its final rules for reducing carbon emissions from new, modified or reconstructed units (111(b)) and existing units (typically referred to as the Clean Power Plan or 111(d)) along with a proposed Federal Implementation Plan (FIP). Overall the final rule for the Clean Power Plan (CPP) calls for a 32% reduction in power plant CO₂ emissions by 2030 from 2005 levels. States more dependent on coal face greater emissions reductions. Indiana is required to reduce CO₂ emission by 39% from EPA's 2012 baseline by 2030. In February 2016, the U.S. Supreme Court issued a stay of the CPP. The stay freezes implementation of the rule until the judicial review process for the rule is complete. In March 2017, President Trump requested that the U.S. Court of Appeals for the District of Columbia halt its review of the legality of the CPP. He also signed an Executive Order directing the EPA to review the CPP, with the focus upon potentially dismantling the plan. These actions will undoubtedly increase the legal uncertainty surrounding the rule as well as likely extend the compliance timeline by two to three years assuming that the regulation survives judicial review.

The state of Indiana, already a participant in the legal challenges to the rule, chose to end planning for CPP implementation as a result of the stay. In the absence of state activities, utilities and independent third parties continue to refine analysis and compliance strategies with large variations due to uncertainty discussed above.

While the final outcome of the CPP is still uncertain, recent market trends have created a situation that resembles a possible future with the regulation in place. Natural gas fired generation has increased due to low prices spurred by a large supply expansion from unconventional sources. In addition, tax credits, state mandates and declining capital costs have fueled the growth of renewable energy investments. Over this time load growth has slowed due to a combination of energy efficiency gains, economic slowdown and a decline in the energy intensity of gross domestic product. These trends have combined to reduce the amount of coal in the overall generation mix of the U.S. from 45% in 2010 to 32% in 2016.

The EPA's modeling of the CPP did not anticipate the absence of coal from the generation mix. In fact it estimated that coal generation would account for 28% of U.S. electricity supply in 2030 not far from 2016 levels. The market trends are potentially creating new expectations for baseload coal resources. In particular, baseload coal resources will need to become more flexible and may start to be viewed as intermediate resources with strong seasonal run times in the summer and winter. The Merom station has experienced a reduction in capacity factor in recent years related to these trends and similar capacity factors are forecast for the mid-term.

The shift away from baseload coal to renewables and natural gas could increase several sources of volatility. Reliance on natural gas generation, both from increasing capacity factors at existing natural gas plants and new builds to replace retiring coal capacity, would raise power market sensitivity to swings in natural gas fuel prices. Moreover, increases in renewable energy generation drive down marginal energy prices in times of high resource output creating a low price situation due to zero fuel costs. When wind and solar resources are not available more and much higher priced generation has to dispatch to cover the gap. The result will be a wider spread between high and low prices (volatility) occurring more frequently than in the past.

Another potential impact of increasing coal retirements and replacing the energy production with renewables will be an increase in capacity price. In a situation similar to being exposed to a volatile

energy market, Hoosier Energy may face increased risk surrounding capacity prices if historical capacity resources are reduced and create a short capacity position.

3.3.2 Economic Factors

Fuel Prices and Fuel Practices

Hoosier Energy fuel and commodity procurement activities are essentially made up of the following material acquisitions:

- Coal
- Natural gas
- Lime (for flue gas desulfurization sludge stabilization)
- Limestone (a reagent for SO₂ removal)
- Fuel oil (for unit start up)
- Chemical additives for FGD
- Ammonia for SCRs
- Soda Ash for sulfuric acid emission mitigation

Historically, Merom Station burns 3,000,000 tons of Illinois Basin high sulfur coal each year. The program scope for coal includes procurement of both fuel and transportation. Currently, Hoosier Energy acquires all of its annual coal requirements under a blend of short-term and longer-term contracts. Historically, a limited percentage of annual requirements have been acquired on the spot market. Hoosier Energy has the option of receiving coal shipments either by rail or truck at the Merom generating facility.

Coal is Hoosier Energy's primary fuel supply and represents one of its largest expenses. Hoosier seeks to maintain a low risk profile regarding available supply and price stability. Medium to long-term contracts, employing price re-openers, and maintaining adequate inventory levels generally support this goal. Spot purchases and short-term contracts also supplement contracts as market or operating circumstances warrant. Merom inventory levels target a 45 to 60 day supply (450,000-600,000 tons). Table 12 shows Hoosier Energy's recent historical coal costs.

Fuel Cost (\$ per MWh)	2014	2015	2016
Merom	23.33	24.08	22.36

Table 12: Merom's Recent Historical Fuel Costs

Natural Gas and Transportation

Hoosier Energy and Wabash Valley Power are joint owners of the Holland facility and are responsible for procuring natural gas and gas transportation. For the initial operating period, the parties entered into a contract with Tenaska Marketing Ventures to supply natural gas and transportation to Holland. Tenaska was the supplier under prior ownership and has proven to be a

reliable and appropriate service provider. Hoosier and Wabash are continuing discussions concerning the upcoming supply agreement extension.

Hoosier executed an agreement with CIMA, LTD to provide for supply and transportation of natural gas to Worthington Generating Facility. Transportation of supply to Worthington Generation is provided through existing agreements between CIMA, Hoosier Energy, and Texas Gas Transmission. Hoosier administers an Hourly Overrun Transportation (HOT) and Park & Loan (PAL) Service Agreements with Texas Gas to satisfy the supply needs of all four units.

In May 2017, Hoosier Energy entered into an agreement with Citizens Energy Group to connect the Worthington generating facility to their supply system. Having a supply line from Citizens will provide both reliability and fuel diversity to the plant by establishing access to multiple major interstate pipelines as well as Citizens' natural gas storage field. The in-service date for this connection was December 2017.

Transportation of supply to Lawrence County Generation is provided through a new marketing agreement with Sequent Energy, Hoosier Energy, and ANR Pipelines. These changes have provided Lawrence County greater flexibility in transportation and more competitive pricing, thereby creating increased efficiencies and reduced cost to satisfy the supply needs of all six units.

Avoided Cost Calculation

As defined in 170 IAC 4-7-1 (b), "avoided cost" means the incremental or marginal cost to a utility of energy or capacity, or both, not incurred by a utility if an alternative supply-side resource or demand-side resource is included in the utility's IRP. Table 13 presents Hoosier Energy's calculation of the avoided Demand and Energy costs for the years 2018 through 2037 in nominal dollars per kW-month and dollars per MWh. These rates are based upon the cost of a generic Combustion Turbine and have been developed consistent with the IURC's QF calculation. The annual costs have been escalated by a percentage rate consistent with the annual increase in the capacity and energy cost assumptions employed by PA Consulting in the IRP modeling. Hoosier Energy included the potential avoided transmission cost in the evaluation of DSM resources.

	Avoided Fixed Cost (\$/kW-mo)	Avoided On- Peak Energy Cost (\$/MWh)	Avoided Off- Peak Energy Cost (\$/MWh)
2018	\$ 1.34	\$ 32.94	\$ 23.63
2019	\$ 2.71	\$ 31.44	\$ 23.12
2020	\$ 3.37	\$ 31.11	\$ 23.00
2021	\$ 10.48	\$ 31.08	\$ 22.97
2022	\$ 24.10	\$ 31.43	\$ 23.80
2023	\$ 30.64	\$ 33.30	\$ 25.24
2024	\$ 31.09	\$ 34.05	\$ 25.96
2025	\$ 30.20	\$ 35.91	\$ 27.60
2026	\$ 29.70	\$ 37.00	\$ 28.44
2027	\$ 30.36	\$ 37.66	\$ 29.07
2028	\$ 31.20	\$ 38.91	\$ 30.19
2029	\$ 31.96	\$ 40.14	\$ 31.27
2030	\$ 32.85	\$ 41.15	\$ 32.19
2031	\$ 33.34	\$ 42.29	\$ 33.27
2032	\$ 33.45	\$ 44.17	\$ 34.74
2033	\$ 33.71	\$ 45.43	\$ 35.90
2034	\$ 33.66	\$ 46.68	\$ 37.01
2035	\$ 33.34	\$ 47.98	\$ 38.17
2036	\$ 33.63	\$ 48.71	\$ 38.99
2037	\$ 34.37	\$ 49.78	\$ 39.84

Table 13: Summary of Avoided Costs

3.3.3 Transmission Resources

Analysis of Existing Utility Transmission System

Hoosier Energy cooperates with all utilities within the Midcontinent ISO as well as our regional reliability council, ReliabilityFirst Corporation (RFC), to ensure that system changes are compatible with an orderly, economic and reliable development of the entire grid.

Hoosier Energy currently has physical interconnections with the following utilities:

- Big Rivers Electric Corp. (Big Rivers)
- Duke Energy Indiana
- Vectren
- Indianapolis Power & Light Company (IPL)
- Ameren

Hoosier Energy's transmission system consists of more than 1,700 miles of transmission line at 69 kilovolts (kV), 138 kV, 161 kV, and 345 kV. Approximately 56 percent of the member systems' power requirements are delivered to Hoosier Energy substations and delivery points using the transmission facilities of Duke Energy Indiana, Vectren, IPL and Ameren. The remainder is delivered through Hoosier Energy's transmission facilities.

Hoosier Energy's system presently includes twenty-five primary substations and approximately 315 distribution substations/delivery points. The distribution substations that serve the member systems are owned in part by Hoosier Energy and the member system. Hoosier Energy owns all the high voltage equipment, transformers, regulators, metering, the low voltage bus disconnect, all associated structures, the property and all in-ground fixtures (foundations, grounding, fencing, etc.). The member systems own the low voltage equipment and structures used for the service to the distribution circuits. Hoosier Energy performs the required maintenance on the entire substation and is responsible for upgrading of the transformer, etc., to meet increased requirements.

Hoosier Energy must coordinate any maintenance outages, expansions or upgrades on its bulk transmission system with the MISO and report these improvements to Reliability First (RF). Hoosier Energy personnel and contractors actively participate in various MISO and RF committees and work groups. Hoosier Energy complies with NERC standards that are enforceable under FERC Order 693 (reliability) and FERC Order 706 (cyber). Hoosier Energy has recently been audited by Reliability First in 2015 (reliability) and 2016 (cyber). The next reliability audit will occur in 2018. RF is one of eight regions that enforce NERC reliability standards. Significant man-hours, documentation procedures and maintenance tracking software has been added in an effort to adequately comply with such reliability standards under Hoosier Energy's Internal Compliance Program, Administrative Bulletin 28 and Board Policy 3-7. The compliance effort extends throughout the company and continues to expand to involve facilities at the Merom Station.

Transmission Access

Member system loads and power purchases from outside Hoosier Energy have costs associated with them for transmission access, either through agreement with the specific utility involved, or the MISO. The MISO transmission expansion cost allocation methodology requires Hoosier Energy to bear some cost of regional transmission projects. MISO continues efforts to reduce congestion throughout the footprint and recently begun an analysis that could lead to significant expansion of the bulk transmission system.

Capital Asset Management

Capital asset management is focused on ensuring that required maintenance is performed and necessary investments are made to economically maintain the long-term safety, security, adequacy, and reliability of these power delivery assets. A critical element of asset health that must be considered in the long-term planning process is the aging infrastructure of Hoosier Energy’s transmission system; the majority of which was built more than 45 years ago. The current rate of asset replacement will eventually become insufficient to maintain reliability as those assets exceed the end of their serviceable lives. Hoosier Energy performs comprehensive asset inspections to determine which assets require replacement before substantial degradation or failure affects reliability. Ongoing comprehensive inspections, which began in 2015, will continue to guide sustainable asset replacement strategies.

Table 14 displays Hoosier Energy’s expected future transmission investment through 2027.

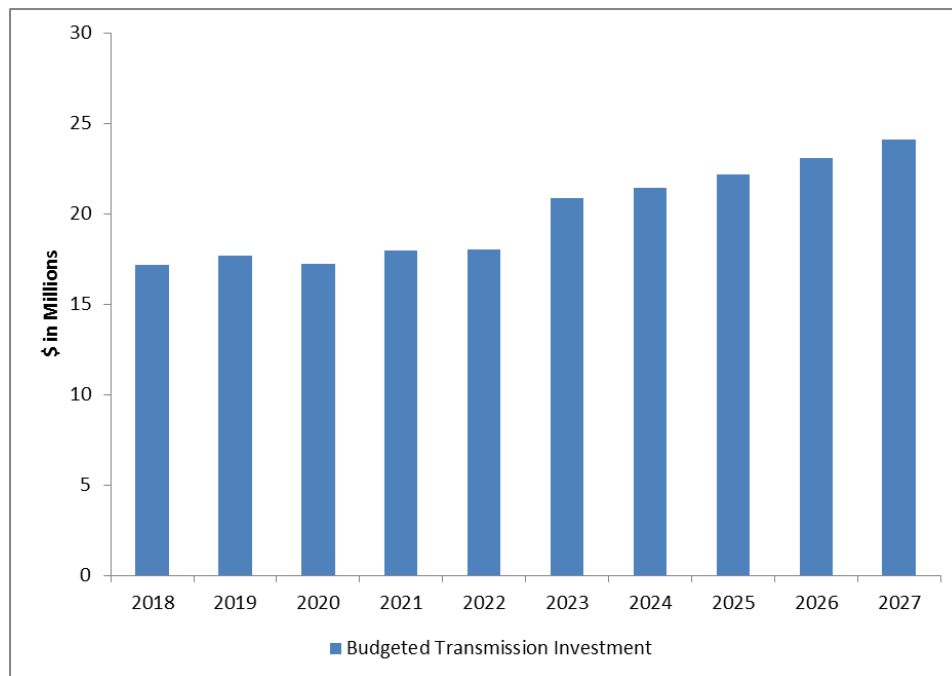


Table 14: Budgeted Transmission Investment

Operations & Maintenance

The operations and maintenance (O&M) function drives the development and execution of maintenance planning practices. These practices are designed to identify equipment maintenance tasks based on the health of equipment assets. Equipment asset health is determined through periodic inspections, monitoring, calibration, evaluation, testing, and repair. The purpose of the maintenance program is to ensure equipment asset health is sustained to ensure the highest level of reliability in a cost effective manner that protects and prolongs asset life.

The operations and maintenance functions serve to collect and report data points for maintenance planning as well as to construct, repair and replace equipment assets. Equipment assets include

substations, transmission lines, communications equipment, and all equipment related to these major assets. In addition to equipment assets, property assets such as rights-of-way (easements) and real property are maintained under a vegetation management program. This program is generally governed by a Transmission Vegetation Management Program (TVMP) which develops the guidelines used to effectively manage vegetation on Hoosier Energy's property assets and undergoes continual improvement as methodologies and equipment evolve and within the scope of current and evolving NERC/RF requirements. The operations and maintenance functions serve as the executing entity for all transmission system maintenance plans, TVMP, and capital improvement projects including oversight of select contractors.

FERC Form 715

Historically, Hoosier Energy has performed an annual analysis of its transmission network to determine whether the system can reliably support the loads and resources placed upon the network. Beginning with the 2014 filing, this analysis, FERC Form 715 Annual Transmission Planning and Evaluation Report (FERC Form 715), will be filed by the Midcontinent ISO as part of the Regional FERC Form 715 filing made on behalf of the Transmission Owning members of MISO. All power flow studies and dynamic simulations incorporated into the FERC Form 715 filing were performed by MISO as part of its MISO Transmission Planning Process (MTEP) and are not specific to Hoosier Energy. MISO's annual MTEP plan assesses transmission requirements and proposes projects to maintain a reliable electric grid and deliver the lowest-cost energy to customers in the MISO region. FERC Form 715 is considered to be Critical Energy Infrastructure Information (CEII).

Hoosier Energy periodically prepares a long-range plan (Plan) as a guide for developing the system to meet present and future needs of its consumers. The purpose of the Plan is to study the current system, including asset health projections, identify system shortfalls and develop system mitigation measures that will provide the most practical and economical means of serving future loads.

The Plan was developed to examine the ability of the Hoosier Energy system to serve the projected load levels for the near term (year 0 to year 5) and longer term (year 10) planning horizons. This Plan included additional study models to align with NERC TPL001-4 Standards. Hoosier Energy is a winter peaking system, therefore, the summer peak, light load and winter peak loading conditions were evaluated. In addition to the ability to serve projected load, the health of existing assets is considered in the Plan.

Results from the transmission studies show that there was no loading in the base case above 100%. Overloads were observed during certain single contingency conditions. The overloads can be mitigated with operational procedures, so other mitigation measures are not required for the long-range plan.

Low voltage issues were observed during base case (N-0) analysis. The low voltage issues during the base case scenario can be mitigated by either adding capacitor banks to the low voltage areas or upgrading the system to increase voltages. This study used capacitor banks to mitigate low voltage issues.

Low and high voltage issues were also observed during the single contingency (N-1) analysis. In addition to the capacitor banks to be added for the base case low voltage issues, current operating

guides, either performed by Hoosier Energy or MISO, were identified to address voltage violations as the preferred approach as opposed to adding additional capacitor banks.

3.4 Capacity Expansion Plan and Energy Requirements

Table 15 presents the Capacity Expansion Plan for the period from 2018 through 2027. This table compares the Summer Peak Demand requirements, as determined through load forecasting, to existing and planned future resources. Hoosier Energy does not project any impact to generation capacity as a result of additional retirements, derating, plant life extensions, repowering or refurbishment. Table 16 compares total energy requirements to expected generation and other system resources.

Capacity Expansion Plan - Summer Peak

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Peak Demand										
Demand Forecast (1)	1,524	1,544	1,562	1,578	1,599	1,628	1,642	1,656	1,670	1,682
Demand Response/Energy Efficiency	(46)	(47)	(46)	(45)	(46)	(47)	(49)	(50)	(50)	(50)
Reserve Requirement (2)	124	126	127	129	130	133	134	135	136	137
Peak Requirement	1,602	1,623	1,643	1,662	1,683	1,714	1,727	1,741	1,756	1,769
Resources (MW)										
Merom	983	983	983	983	983	983	983	983	983	983
Power Purchase	150	150	150	150	150	150	50	50	0	0
Holland	307	307	307	307	307	307	307	307	307	307
Worthington	169	169	169	169	169	169	169	169	169	169
Lawrence	175	175	175	175	175	175	175	175	175	175
Renewables (3)	122	97	247	347	347	347	347	347	347	347
Adj. per MISO RAR (4)	(196)	(171)	(294)	(375)	(375)	(375)	(375)	(375)	(375)	(375)
Total Resources Adjusted	1,709	1,709	1,736	1,755	1,755	1,755	1,655	1,655	1,605	1,605
Total Resources minus Peak Req.										
Excess / (Deficit)	107	87	93	94	72	42	(71)	(86)	(151)	(164)

1 2017 Power Requirements Study Base Case Summer Peak Demand - Without Demand Response/Energy Efficiency

2 Assumed long-term Midwest ISO reserve requirement of 8.40%

3 Estimated Renewable Resources

4 MISO Resource Adequacy Requirements - Based upon current MISO capacity rules and plant performance, both of which are subject to future changes.

Table 15: Summer Peak Demand Requirements

Source: PRS and Integrated Resource Plan

	Year	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>
<u>Energy Requirements (GWh)</u>						
Members		7,657	7,746	7,819	7,889	7,944
Surplus Sales		1,165	980	1,012	1,033	1,051
Total Energy Required		8,822	8,726	8,831	8,922	8,995
<u>Energy Resources (GWh)</u>						
Merom		5,058	4,869	4,853	5,087	5,067
Power Purchase		855	855	857	856	859
Holland		527	592	580	515	537
Worthington		46	42	55	51	57
Lawrence County		33	27	34	32	35
Renewables		378	382	529	526	526
Spot Purchases		1,925	1,959	1,923	1,855	1,914
Total Resources		8,822	8,726	8,831	8,922	8,995

Table 16: Annual Energy Requirements 2018 - 2022

Source: Hoosier Energy 2018 – 2022 Business Plan and Integrated Resource Plan

Section 4: Selection of Future Resources

4 Selection of Future Resources

Pursuant to 170 IAC 4-7 Section 7, this section presents the process that Hoosier Energy uses to select future resources. Table 17 lists the resources that are generally available for consideration in the IRP. Each alternative is evaluated based on construction cost, operating cost, reliability, environmental impacts, maturity, availability⁷ and flexibility⁸. The cost information is obtained from various industry and market resources, including the Energy Information Administration (EIA), the National Renewable Energy Laboratory (NREL) and Hoosier Energy consultants.

Potential Resource Options
Wholesale Rate Design
Demand-Side Resources
Market Power Purchases
Long-Term Power Purchases
Combustion Turbines
Natural Gas Combined Cycle
Coal-fired Generation
Wind Generation
Solar Generation
Other Renewable Resources
Distributed Generation
Non-Utility Generation
New Technologies
Transmission Facilities

Table 17: Potential Resource Options

Initially to consider each of these technologies, a qualitative screening analysis is performed, to identify the resource options suitable to the Hoosier Energy system.

- Does the resource match Hoosier Energy’s need?
- Is the resource appropriate for Hoosier Energy’s service territory?
- Is the technology commercially available and reliable?
- Are the costs and reliability of the technology quantifiable?
- Does the resource meet expected environmental standards at a reasonable cost?

Resource options that pass the qualitative screening are promoted to a second step where it was quantitatively evaluated. For the quantitative screening, the capacity alternatives were evaluated based on the previously mentioned items of cost, reliability, and the maturity of technology.

The quantitative screening can be thought of as a series of three tests as illustrated below.

1. Installed Cost: Computation of installed cost in \$/kW for each resource option.

⁷ Defined as the ability to generate when necessary.

⁸ Defined as the ability to respond to changes in demand.

2. Monthly Fixed Costs: The fixed cost to install the technology which includes debt service costs. This value is then levelized to arrive at a monthly cost on a present value basis.
3. Equivalent Average Cost: The average annual cost in \$/MWh which includes both fixed (capital and O&M) and variable costs to generate electric power at a certain capacity factor. The computation represents a “levelized” rate so that costs are presented on a present value basis.

The resource options are then compared against the aforementioned tests to arrive at the least cost supply-side resource plan.

4.1 Wholesale Rate Design

The current tariffs, as described in Section 3.2.2, were reviewed with the member systems through the Members’ Managers Association and rates updated by Hoosier Energy in 2017. The structure of the wholesale tariffs were confirmed, and rates updated, for implementation in April 2019. The wholesale tariffs are designed to encourage demand response participation by the member systems and to introduce time-of-use energy pricing. Hoosier Energy periodically reviews and updates its rate design for reasonableness and applicability to current market conditions.

4.2 Demand-Side Resources

In 2009, Hoosier Energy completed an extensive analysis of energy efficiency and demand-side management programs. This work was performed by GDS Associates and Summit Blue Consulting and has been updated several times, most recently in 2016. The individual measures recommended by the analysis, and approved through a collaboration with Hoosier Energy’s Member Systems, are then offered to customers through the DSM program. An effort is made to offer a menu of programs to ensure all customers the opportunity to participate. The demand and energy savings and economic benefits of each measure are included in Hoosier Energy’s 2016 Demand Side Management Annual Report, which is provided as Appendix F. The DSM Report provides a description and estimated performance through 2016 and also describes changes for the future.

4.3 Supply-Side Resources

4.3.1 Market Power Purchases

The wholesale power market has developed standard products that are commonly traded in increments of 50 MW for specific hours of the day or week, such as on-peak hours (5x16), around-the-clock hours (7x24), and wrap hours (weekend 2x16 + off peak 7x8). The two most common products are forwards and options. Forward contracts are take-or-pay and, over the period of one month or more, amount to a capacity factor of approximately 45% making forwards an intermediate resource. Option contracts provide the buyer a day-ahead call on the energy. Therefore, options are more of a peaking resource but usually lack intra-day flexibility. With the MISO LMP market, the industry continues to transition to financial products as primary risk management tools.

Hoosier Energy actively participates in the wholesale market to serve member load and maximize the value of resources. Hoosier Energy is a member of ACES, which acts as Hoosier Energy’s agent for wholesale transactions. ACES is owned by and is the market broker for 22 cooperative members and has a working knowledge of the power market. ACES uses this market knowledge

to develop proprietary market pricing information. Hoosier Energy uses information from ACES and other sources to make resource decisions.

4.3.2 Long-Term Power Purchases

Long-Term power purchases are generally at least one year in length and up to 20-30 years. Long-Term purchases may allow for a more diverse portfolio of generation assets, can reduce operating risk, unit contingent risk, and diversify fuel and power supplies. Long-Term Purchases also provide the opportunity to add a resource without taking on construction and operating risk.

Hoosier Energy recognizes the value of purchases as part of a diverse portfolio of generation resources. Hoosier Energy will continue to seek power purchases as not simply an alternative but also as a complimentary component to owned generation assets.

4.3.3 Combustion Turbines

Combustion turbines (CT) are generally used for peaking needs and to satisfy capacity requirements. The primary fuel for CT is natural gas with some potential for diesel as a back-up fuel. The key characteristics of CTs include low capital costs, quick start capability, short construction time and somewhat high variable cost. A shorter decision-making lead-time of for procurement, licensing and construction make CTs an attractive option from a flexibility standpoint. Hoosier Energy monitors the capacity and variable costs of the CT resources based upon quotes from vendors and consultants, as well as industry publications.

4.3.4 Natural Gas Combined Cycle Generation

Natural Gas Combined Cycle (NGCC) capacity is preferred for providing intermediate to baseload energy needs. While variable operating costs are generally lower than CTs due to greater efficiency, capital costs are higher. NGCCs require a larger footprint and usually greater amounts of water for cooling. Due to efficiency degradation if cycled, in order to recoup higher fixed costs, NGCCs are likely to be economical with annual capacity factors above 25-30%.

New NGCCs have traditionally been at a disadvantage in the Midcontinent region versus existing coal-fired, baseload resources. The incremental cost of the older coal facilities tended to drive the forward market and supply the region's baseload and intermediate energy needs. However, due to environmental regulations and natural gas price decreases due to improvements in extraction technology, NGCCs are increasingly on the margin in the spot and forward markets of the Midcontinent region. Future environmental regulations are likely to improve the economics of natural gas-fired combined-cycle facilities due to the CO₂ emission advantage versus coal generation.

4.3.5 Coal-fired Generation

Baseload coal generation is a supply-side option for consistent, baseload demand and energy needs. Baseload coal units are characterized by high capital costs with low operating and fuel costs. In the past, the economics and availability of Illinois Basin coal, along with government restrictions on the use of natural gas, made baseload coal generation an attractive resource for Indiana utilities. However, given the likelihood of carbon and/or greenhouse gas regulation in the future, new coal generation appears unlikely due to increased environmental risks.

A coal-fired Integrated Gasification Combined Cycle unit with Carbon Capture Sequestration (IGCC w/CCS) may be a viable supply-side resource option. An IGCC uses a gasifier to convert coal to syngas and then removes impurities from the syngas before it is combusted. This results in lower emissions of sulfur dioxide, particulates, and mercury. With additional process equipment, the carbon in the syngas can be shifted to hydrogen via the water-gas shift reaction, resulting in nearly carbon free fuel. The resulting carbon dioxide from the shift reaction can be compressed and stored. Excess heat from the primary combustion and syngas fired generation is then passed to a steam cycle, similar to a combined cycle gas turbine. This results in improved efficiency compared to conventional pulverized coal.

The economics of IGCC versus natural gas combined cycle is highly dependent upon the price of coal versus natural gas. In general, given the current abundance of domestic natural gas, resulting prices and forecast of similar expectations in the future, the higher capital and operational costs associated with IGCC technology are difficult to justify.

4.3.6 Wind Generation

Energy from wind resources has become a prominent component of most resource plans as cost reductions due to technology improvements allow wind to be more competitive. The problem with wind generation remains the intermittent nature of the resource, which means the value is significantly lower due to the intermittent and unpredictable nature. Another hurdle for wind resources is the availability and expense of sufficient transmission infrastructure to move the wind energy from producing regions to load centers.

The installed cost of wind ranges from \$1,500 - \$2,300 per kW, depending upon the size of the installation.⁹ For purposes of the IRP, a 100 MW Wind PPA was used as a proxy to model wind generation. The assumed PPA has a 20-year term with an energy cost of \$35/MWh in 2018 dollars, escalated based upon the annual escalation factor found in the NREL's 2016 Annual Technology Baseline. The initial cost assumption is based upon recent prices for Indiana/Illinois wind generation during the past 12–24 months.

4.3.7 Solar Generation

Due to decreasing costs of photovoltaic panels, solar energy generation is becoming more economically competitive relative to other supply-side resources. The intermittent nature of solar generation tends to limit its value unless paired with energy storage. The cost for generating solar power through a utility-scale program is significantly less per kilowatt hour when compared with individual, smaller scale systems.

The installed cost of Solar PV ranges from \$1,600 - \$2,000 per kW for a utility-scale PV installation to \$5,000 - \$7,500 per kW for a Concentrating Solar Power installation including storage⁹. For purposes of the IRP, a 200 MW Solar PPA was used as a proxy to model solar generation. This PPA has a 20-year term and used an energy rate of \$36/MWh in 2018 dollars and was escalated based upon the annual escalation factor provided by NREL's 2016 Annual Technology Baseline. The initial cost assumption for the Solar PPA was based upon recent price quotes for Indiana and surrounding states during the past 12–24 months.

⁹ National Renewable Energy Laboratory – 2016 Annual Technology Baseline

4.3.8 Renewable Resources

Other resources considered renewable are technologies fueled by landfill gas, coalbed methane and biomass. These technologies can be promising as continued technological advances increase efficiencies and experience reduces the development and operating risk. However, in order to be cost effective versus other resources, these technologies generally require a specific need, such as a requirement to find an alternate method to dispose of waste. In addition, in order to be cost competitive these technologies generally require a sufficient, reliable and economically advantageous fuel source.

Other alternative energy projects, such as cogeneration and coal waste technologies, may or may not qualify as renewable energy but could prove economic and provide supply-side diversification. Hoosier Energy has analyzed a number of these proposals and has demonstrated a commitment to considering all economically viable renewable energy resources.

The Hoosier Energy Board of Directors adopted a Renewable Energy Program (Board Policy 5-2) that defines targets and evaluation criteria for renewable projects. As originally adopted, Hoosier Energy's policy sets a goal to secure 2% of total energy generated from renewable resources by 2011 with additional resources going forward matching 5% of member energy growth. As Hoosier Energy has met the initial policy goal, the policy was revised in 2014 to set a target of obtaining 10% of member energy requirements from renewable resources by 2025. The prospective addition of a 200 MW Solar PPA beginning in 2020 will achieve the 10% by 2025 renewable energy target.

4.3.9 Distributed Generation

Options for distributed generation include both fossil and renewable sources. On the fossil side, the cost of distributed generating capacity for diesel or gas turbines is estimated to be greater than \$1,000 per kW. The actual cost is highly dependent upon a number of factors, including the type of engine (diesel reciprocating engine or gas turbine), size, manufacturer, emission level, efficiency, etc. Given the higher capital cost, the economics of distributed generation does not compare favorably to central station power without a customer specific need for increased reliability and/or an economically advantageous fuel source.

Hoosier Energy's Member systems have 256 distributed solar and 24 distributed wind generation customers. These customers installations have a nameplate capacity of 2.2MW of solar and 0.1MW of wind. Hoosier Energy and its Members have adopted a consistent compensation mechanism applicable to all installations of less than 50kW. The rate is based upon Hoosier Energy's projected variable production cost from the G&T's Budget and provided to the members in October for the upcoming budget year.

For customer-owned generation qualifying facilities greater than 50kW (and less than 20MW), Hoosier Energy and its Member Cooperatives have adopted a policy that requires excess energy to be purchased by Hoosier Energy under Schedule CPP. Schedule CPP is consistent with the IURC's QF rules and includes the following compensation amounts:

If the qualifying facility meets the requirements of Schedule CPP, Hoosier Energy will purchase energy at the following rates:

For all on-peak energy supplied	\$0.03951 per kWh
For all off-peak energy supplied	\$0.02694 per kWh.

Hoosier Energy may also purchase capacity supplied from the QF in accordance with the conditions and limitations of the contract at the following minimum rate:

Unadjusted rate for Capacity	\$4.02 per kW-month.
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There are currently no customers with qualifying generation facilities taking service under Schedule CPP.

4.3.10 Non-Utility Generation

Commercial and industrial (C&I) consumers served by Hoosier Energy members have expressed growing interest in developing renewable energy resources adjacent to their facilities. Hoosier Energy and the cooperative member staff have met with several C&I consumers interested in on-site generation to discuss projects ranging from a few hundred kW up to 10 megawatts of capacity with most projects averaging 1 MW. Interest is motivated by multiple factors including corporate sustainability policies and goals, support for marketing programs based on green attributes, pressure from customers who encourage or offer incentives to suppliers to use renewable energy, and interest in locking in a portion of energy costs at a fixed price. Recruiting employees was cited by one business that thought a solar array might help attract new graduates to the company.

C&I interest in on-site renewable generation may accelerate as the cost of solar drops further, as a result of tax credit extensions, as momentum builds at business groups that encourage renewable energy, and as a result of increased marketing by solar vendors. Some companies, including large data centers, are also beginning to include “renewable friendly policies” at utilities in their site selection process.

In response, Hoosier Energy changed Board Policy to provide member systems and the G&T with new tools and renewable generation options that members can offer these consumers. The change, approved in 2016, authorizes Hoosier Energy to work with member cooperatives, end consumers and developers to build on-site generation at C&I locations, largely through purchase power agreements (PPA’s), and pass contractual obligations and costs through the distribution co-op to the C&I consumer via “take or pay” agreements. This is a significant step to better facilitate retail customer interest in on-site renewable energy technologies.

4.3.11 New Technologies

Hoosier Energy monitors mature and emergent generation technologies as potential options to provide low cost, reliable generation. Variable demand power markets, environmental regulations and economic conditions have caused a heightened interest in novel cycle technologies that accommodate intermittent cycles from renewable generation as well as for adding smaller blocks of incremental capacity.

- Adaptive Generation Resources - Certain technologies that convert mechanical work to electrical energy have been in existence for some time now, and have been increasingly incorporated into the bulk electric system. Increasing intermittent generation requires flexible power sources for voltage regulation, grid stabilization and load balancing. Base load and intermediate load facilities cannot easily accommodate the increased penetration of variable generation seen on the electric grid due to thermal

cycles and slow ramp rates. As a result, non-conventional sources of generation are finding a place in bulk electric generation.

- Reciprocating Internal Combustion Engine (RICE) - Reciprocating internal combustion engine (RICE) is a mature technology that has grown in popularity for use in the electric power generation sector. Historically, RICE was not considered for power generation due to economies of scale; however, utilities have increased interest in RICE because of flexibility, complete life cycle costs and operating characteristics including:
 - Flexibility – fast start and fast ramping
 - Modularity – increments of 1 to 20 MW
 - Fuel Diversity – biogas, hydrogen, natural gas, landfill gas and diesel
 - Low Emissions – clean burning requiring minimal water usage
 - Low capital cost – comparable to NGCCs from \$900 to \$1500 per kW

Presently, over 11,000 MWs of RICE generation support the bulk electric system and nearly 2,000 MWs planned for installation.¹⁰ Hoosier Energy is an active participant in the Electric Power Research Institute (EPRI) RICE interest group, which aims to assess the potential need and fit of RICE in the new power market, as well as better understand operating costs and technology characteristics. Information gained in this research may assist in the assessment for restarting the Osprey Point facility, which was idled due to economic reasons in 2016. Restarting the Osprey Point facility remains an option for future generation.

- Battery Storage - Battery storage falls in the broad category of energy storage and is now in the deployment phase of the technology continuum for electrical generation. Frequency regulation and grid support are primary drivers of commercial deployments for battery storage however, as battery costs continue to decrease, a shift towards multiple services such as capacity, ramping support and ancillary services is expected. Further, utility scale projects ranging from 2 to 100 MW have been installed and interconnected to the grid in MISO, PJM and California since 2013. Presently, 562 MWs of battery storage are interconnected to the electrical grid and another 242 MWs are planned.

There is a variety of battery technologies available including metal air, flow, sodium chemistries, lead acid and lithium ion. While lead acid is the most mature, lithium ion is the most widely selected technology by utilities, and in fact is the only battery technology that has advanced from grid support to the bulk-energy management level. Sodium sulfur batteries offer high density and efficiency, and are used for grid support but have experienced some safety concerns throughout the industry. Hoosier Energy is considering applications within its power network for battery storage, and closely following technology advancements, as well as costs. Installed costs for lithium ion technologies, range from \$550/kW to \$2700/kW depending on duty (frequency regulation, grid support, bulk storage) and scale. Potential applications include co-location of a battery storage facility with a consumer solar PV array, or storage located at an existing base load plant to offset auxiliary power during on peak hours.

- Compressed Air Energy Storage - CAES uses off peak electricity to compress air into an underground reservoir, surface vessel or air storage system and when electricity is needed,

¹⁰ Per EPRI.

or prices are high is released. The air is withdrawn, heated with fuel and passed through an expansion turbine to generate electricity. Advantages of CAES is that plants burn 1/3 of the fuel of a CT and corresponding reduction in pollutants. While there are a few, full-scale CAES plants in operation; the technology is relatively immature, requires favorable geologic-geographic conditions and has a relatively poor heat rate.

- Pumped Hydro - Pumped Hydro is a mature technology that is utilized in geographic area where conditions for reservoir storage capacity and elevation changes are favorable. While Hoosier Energy's physical service territory is not well suited for pumped hydro, it is a storage option that is mature and available.
- Flywheel Energy Storage - Flywheel energy storage is primarily used for powering UPS, frequency regulation, wind generation stabilization and power quality. While there are flywheel plants in operation, the technology is relatively immature and not widely used.

Advanced Engine Concepts

Recognizing the growing need for scalable, modular and packaged generation, power generation equipment suppliers are developing novel technologies with the goal of further improving the efficiency of engine based systems. Engine fuel cell hybrid, supercritical CO₂ bottoming cycle and direct carbon injection are technologies in the demonstration and commercial stages that could potentially help Hoosier Energy meet its resource needs in the future. These technologies are discussed further below:

- Engine Fuel Cell Hybrid - Solid oxide fuel cell (SOFC) engines exist at the commercial level and are used with RICE forms of generation achieving 60 to 65% electrical efficiency. The process is known as "fuel cell – combined cycle" where natural gas is supplied to a fuel cell that produces electricity from the fuel cell process, and the tail gas from this process is fed to a reciprocating engine. While this equipment is marketed as distribution level equipment, combining individual engines could result in the production of electricity at the bulk electric system level. Further, existing RICE can be retrofitted with the fuel cell component thus increasing the output and efficiency of the unit.
- Supercritical CO₂ Bottoming Cycle - Supercritical CO₂ (sCO₂) bottoming cycle heat recovery technology obtains a heat source such as exhaust gas from a combustion turbine or RICE and converts it to electricity with a sCO₂ power turbine connected to an electrical generator. This technology utilizes the Brayton Cycle rather than Rankine, which is about 3% to 4% more efficient. CO₂, rather than steam is used as the working fluid to drive the turbine. CO₂ has thermodynamic advantages over other working fluids such as low critical temperature, high density, easy to compress and no phase change during the cycle.

This technology is in the demonstration stage and two vendors have developed working prototype machines. One vendor manufactures a packaged, 8 MW machine designed to retrofit a combustion turbine or RICE which could provide 8 additional MWs from the exhaust flow. In addition, the Department of Energy is actively researching the use of sCO₂ bottoming cycle with concentrated solar. Last, sCO₂ could use direct fired natural gas as the heat source. Vendors are working to scale up the machines to 25 MW to accommodate multiple exhaust gas flows.

Hoosier Energy is closely following sCO₂ technology primarily because its portfolio has 320 MWs of combustion turbine capacity, and 33 MWs of RICE, which provides a significant opportunity to add capacity with sCO₂ turbines in the future. Hoosier Energy is participating in a Supercritical CO₂ Brayton Power Cycle Pilot at Southwest Research Institute with the Electric Power Research Institute and Department of Energy, to gain advanced knowledge of this technology. The final report will be published in December 2017. The technology is expected to be mature in the mid 2020's.

- Direct Injection Carbon Engine - Direct injection carbon injection (DICE) is a diesel engine modified to enable combustion of water based slurry of micronized refined carbon (MRC) fuel. DICE is a mature technology but not widely used. Engine technology and coal water system advancements are enabling renewed interest in DICE technology. Emissions may be lower for DICE due to combustion temperatures and the use of hydro desulfurization. DICE is aiming for engines sized in the 65 MW range compared to 1 MW to 20 MW size for RICE. Research is active in Europe and Asia and DICE is being investigated for use with biofuels as well. DICE technology is suited for baseload, peaking and backup duties. The first commercial DICE power plant is expected to be deployed in the early to mid-2020s. DICE is an attractive technology as it utilizes coal, which is an abundant, domestic fuel, but is also clean burning and claims of 30% to 40% lower carbon capture cost than pulverized coal.

Other Technologies

- Fuel Cells - A fuel cell is a device that converts the chemical energy in natural gas or hydrogen into electricity and water through an electrochemical reaction with oxygen. No combustion of fuel takes place during the process, which makes the technology environmentally attractive. Fuel cells are similar to batteries in structure, except they rely upon an external fuel source instead of stored chemical reactants. While there are different types of fuel cells, each is made up of three layers: an anode, an electrolyte, and a cathode.

Fuel cells are an emerging technology and there are very few commercial applications. Fuel cells have a great deal of technical challenges to overcome before successful commercialization takes place. One challenge in particular is the development of a cost-effective fuel reformer that converts the fossil fuel into hydrogen. While research looks promising, the fuel reformer is not perfect and sometimes fails and poisons the fuel cell by passing carbon monoxide and carbon dioxide through the electrolyte.

Another significant challenge is cost. Fuel cells require expensive and sometimes rare earth metals such as yttrium and zirconium. Furthermore, fuel cells are difficult and time-consuming to manufacture. While costs may decline in the future as research continues, fuel cells remain an expensive technology for most applications. At this time, it is not prudent for Hoosier Energy to commit a significant amount of financial resources on technologies that are not "mature."

4.3.12 Transmission Facilities

Hoosier Energy prepares a Long-Range Transmission Plan to serve as a guide for developing its system to meet present and future needs of its consumers. This Plan is updated on a 5-year cycle or as the result of a significant change to the transmission system, whichever is sooner. As described in Section 3.3.3, the purpose of the Plan is to study the current system, including asset health

projections, identify system shortfalls and develop system mitigation measures that will provide the most practical and economical means of serving future loads.

Additionally, as a member of MISO, Hoosier Energy participates in the MISO Transmission Expansion Plan (MTEP) process, which is an annual assessment of the regional transmission system reliability. This process identifies long-term regional transmission requirements and develops a portfolio of projects designed to maintain grid reliability and address congestion issues.

4.4 Future Resource Planning Criteria

4.4.1 Reserve Margin

Reserve margin is likely the most common reliability measure. Reserves are a necessary addition to the resource requirement plan and are used to offset the effects of contingencies that arise either because of generation unavailability or changes in load (e.g. weather effects, customer mix and usage). Reserve margin is defined as follows:

$$\text{Reserve Margin} = \frac{(\text{Total Resources} - \text{Total Load})}{\text{Total Load}}$$

As a member of ReliabilityFirst (RFC), Hoosier Energy is required to adhere to specific standards regarding resource adequacy. Specifically, RFC requires the calculation of a planning reserve margin that will result in the sum of the probabilities for loss of load for the integrated peak hour for all days of each planning year being equal to 0.1. This is commonly referred to as a Loss of Load Expectation (LOLE) analysis based upon a one day in 10 years criterion.¹¹ MISO serves as the Planning Coordinator for RFC and is responsible for annually calculating the appropriate planning reserve margin. The required reserve margin for MISO's 2018 – 19 Planning Year is 8.40%.

This figure is not based upon unforced generation capacity values but rather on forced generation capacity. That is, each generation resource maximum capacity value must be adjusted based upon either:

- a) The unit's historical forced outage rate as supported by GADS data; or if GADS data is not available,
- b) The historical forced outage rate from a similar proxy group of generators as supported by GADS data calculated by the Midcontinent ISO.

The reserve margin requirement is therefore subject to change in the future due to modifications to either the Midcontinent ISO's LOLE analysis and/or to the historical forced outage rates of the generation resources. The capacity figures found in Table 15 reflect values for the planning year beginning June 2018.

4.4.2 Environmental Analysis

A key component of any future comprehensive national energy policy will likely be the establishment of a long-term strategy for addressing climate change with particular focus on electric power generation. In the face of a challenging operating environment, including uncertain energy demand, competition from alternative energy sources and aging power infrastructure, electric

¹¹ ReliabilityFirst standard BAL-502-RF-03

utilities need a clear understanding of future emission reduction obligations in order to make the right investment decisions. This includes further reductions of air emissions as well as future regulatory restrictions on carbon, particulate and other pollutants.

If a new generation facility is selected through the integrated resource planning process and then proposed, Hoosier Energy will comply with all then-current state and federal environmental regulations.

4.4.3 Risk

The preferred plan seeks to position Hoosier Energy in a low market and business risk profile. Risk is broadly defined in three categories: financial, business, and market risk. Financial risk is a consequence of Hoosier Energy's highly leveraged capital structure. Thus, changes in interest rates, for example, can have significant financial impacts. Business risk, that is risk associated with a stable revenue stream, is relatively low as Hoosier Energy, through its member cooperatives, has defined franchised service territories. Taken together, Hoosier Energy's higher financial risk profile has been balanced by its overall lower business risk.

On the other hand, market risk, reflecting price volatility, can be significant. One objective of Hoosier Energy's preferred plan is to lessen risk associated with the market using a strategy of owned resources, long-term purchases and sales and short-term power market purchases and sales. While the current wholesale market provides short-term economic opportunities, that is unlikely to be the case for the long-term.

Another risk mitigation technique that Hoosier Energy has practiced is the use of joint ventures for owned resource. Development of the Lawrence County facility and acquisition of the Holland Facility demonstrates Hoosier Energy's willingness to partner with neighboring utilities. These joint ventures allow for the sharing of risks and reduce overall costs. Hoosier Energy will continue to review such opportunities as they become available.

Hoosier Energy recognizes that it faces a changing environment. A principal goal for this IRP is to develop a plan that will provide the best service and price, using technologies currently available. Whenever possible, the Hoosier Energy resource screening process recognized these effects and evaluated their impact through various scenario analyses.

4.4.4 Transmission Analysis

From a reliability perspective, Hoosier Energy's preference is to interconnect any new supply-side resource to the Hoosier Energy transmission system. Hoosier would be required to follow Midcontinent ISO rules for generation interconnections. The Midcontinent ISO tariff includes rules for both large and small generation interconnection projects.

From a market perspective, Hoosier Energy's preference is to interconnect any new supply-side resource to the Hoosier Energy transmission system to lessen LMP risk (i.e., resources located near load generally reduces LMP risk). Membership in the Midcontinent ISO allows consideration of supply-side options that are within the Midcontinent ISO footprint, with emphasis on options that are both economical and correlated with the locational marginal prices of Hoosier Energy's loads.

Hoosier Energy continues to expand the bulk transmission network to meet local and regional system needs as well as changing RFC criteria. Any bulk expansion plans require review and approval of the Midcontinent ISO through its MTEP process.

Hoosier Energy continuously monitors the need for additional transmission facilities. At the time the need for additional facilities is identified, the timing, type and approximate costs of additional facilities will be developed.

4.4.5 Reliability Analysis

At this time, Hoosier Energy has not evaluated the impact of each potential resource on system-wide reliability, either transmission or generation. It is clear that resources have varying impacts on system reliability. Generation resources may be used for voltage control and reactive support, spinning reserves, and quick and/or black-start capabilities. In addition, properly sited and operated generation resources are more capable of enhancing or increasing available transfer capability (ATC) or total transfer capability (TTC) than purchased power.

4.4.6 Market Analysis

The ability to access the Midcontinent ISO market as a resource for potential capacity and energy purchases or sales allows Hoosier Energy to balance its needs in the short-to-intermediate term. This mitigates the impacts of market price and load volatility. In this IRP, Hoosier Energy has conducted analyses that include individual market exposure tolerance levels of 5 percent, 10 percent and 20 percent above and below member load. Hoosier Energy is also an active participant in many of the Midcontinent ISO committees and working groups. Hoosier Energy will continue to monitor the LMP market and its potential impact on resource planning.

4.5 Results of Initial Screening Analysis

Based upon an initial screening analysis, the list of potential resource options were reduced to those resources that demonstrated economic viability, operational reliability and were flexible enough to meet expected, and potentially more stringent, environmental standards. These resources were then included in the portfolio modeling scenarios developed by PA Consulting. A summary of the screening analysis results is provided below in Table 18.

Resource/Strategy	Net Nominal Operating Capacity (MW)	Fuel Type	Accepted or Rejected as Resource Alternative?	Reason why Resource was Accepted or Rejected
Single Unit IGCC	600	Coal	Rejected	Not cost effective
Natural Gas Conversion	495	Natural Gas	Accepted	Cost effectiveness and Reliability
Holland CC Conversion (2x1 to 3x1)	906	Natural Gas	Accepted	Cost effectiveness and Reliability
Lawrence CC Conversion (2x1 7FA)	655	Natural Gas	Accepted	Cost effectiveness and Reliability
Merom Brownfield CC (1x1 H Class)	464	Natural Gas	Accepted	Cost effectiveness and Reliability
New CT (H Class)	205	Natural Gas	Accepted	Cost effectiveness and Reliability
Combined Cycle PPA	200	Natural Gas	Accepted	Cost effectiveness and Reliability
Reciprocating Internal Combustion Engine	85	Natural Gas	Rejected	Not cost effective
Onshore Wind PPA	200	Renewables	Accepted	Cost effectiveness and Reliability
Solar Photovoltaic PPA	200	Renewables	Accepted	Cost effectiveness and Reliability

Table 18: Summary of Resources Included in Portfolio Modeling

In addition to the above supply-side resources, additional demand-side resources and reliance upon market purchases and sales are resources options to meet future resource needs.

Section 5: Resource Integration

5 Resource Integration

5.1 Introduction

Pursuant to 170 IAC 4-7 Section 8, this section presents the preferred Plan. In order to plan a portfolio of resources that will economically serve its members, while ensuring adequate reliability and minimizing risk, Hoosier Energy began an assessment of resource options. To initiate this analysis, PA Consulting was hired to conduct an assessment of the long-term viability of existing resources from both operational and economic perspectives. This analysis serves as the basis for the 2017 Integrated Resource Plan. The assessment also identifies potential future resources, and the associated cost and operational parameters to be included in the integrated system modeling process.

5.2 Modeling Methodology

To conduct an assessment of Hoosier Energy's supply-side and demand-side resource portfolio under varying scenarios and sensitivities, PA began with the power market models developed in AURORA^{xmp}. AURORA^{xmp} is at the heart of PA's modeling suite with its rigorous unit commitment and true economic dispatch optimization to capture the dynamics and economics of electric power markets. AURORA^{xmp} produces electricity price forecasts, long term capacity expansion modeling, risk analysis, as well as resource and contract valuation.

Together with AURORA^{xmp}, PA has developed other models which allow further steps in the analyses. With these tools PA conducted an in-depth assessment of some of the key electricity market components, such as electricity price volatility, and the impact on Hoosier Energy's resources dispatch into the LMP markets. Finally, PA used internally developed portfolio optimization model to evaluate the hundreds of thousands of possible resource portfolio combinations that could reliably and economically meet the forecast needs. Table 19 below provides a high-level overview of the IRP modeling methodology.

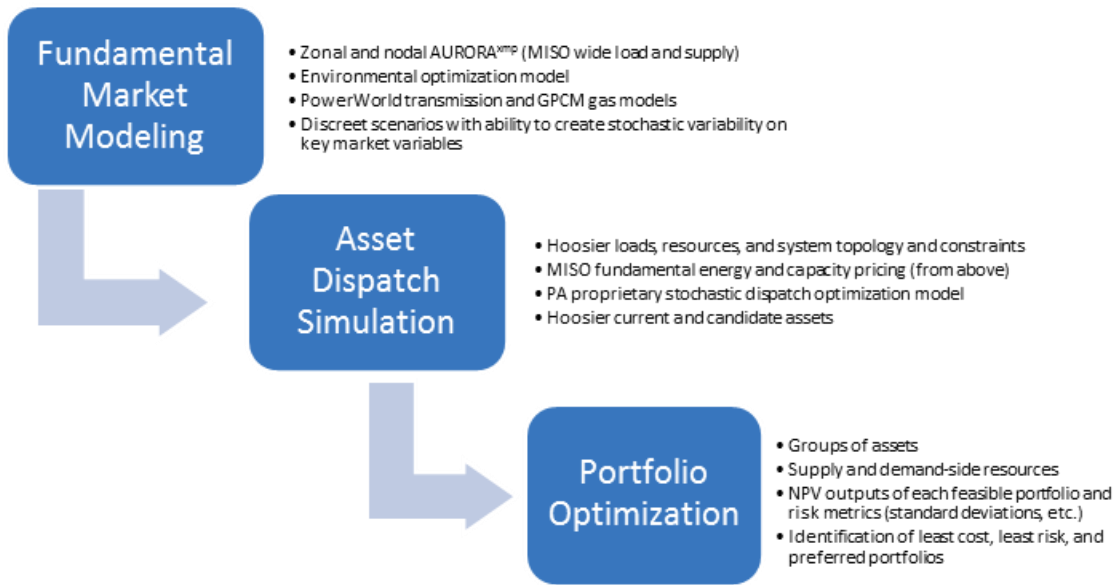


Table 19: IRP Modeling Methodology Overview

Fundamental Market Modeling

In a competitive market, assets dispatch into the market, and the wholesale electricity price is based on the marginal costs of generation. This means prices will rise until the variable costs of the last generating unit meet the demand. Our model is based on this principle. The fundamentals approach reflects the economics and individual characteristics of demand and supply to find the marginal unit per zone. AURORA^{xmp} estimated in an iterative process the MISO market-clearing price for the requested time period and each MISO zone by using hourly demand and transmission constraints as well as the individual characteristics of the generating units.

On the supply side each generating unit is defined in the model with specified fixed and variable cost components, physical characteristics like heat rate and capacity and operating constraints like ramp rates and maintenance rates.

In the long-term analysis changes to MISO’s capacity mix were simulated through retirements of existing and addition of new build units. In addition to publicly announced generator retirements and new builds, the decision for retirements or new builds were also based on economics and the return on investment for an investor. Using the combination of cost components and projected production and associated market revenues, the profitability of each unit was calculated and if a unit was not projected to be profitable over a defined time period, the model assumed it will retire. The opposite accounts for generic new build units which were assumed to be added to MISO if the investment can be recovered in a defined timeframe. PA used the AURORA^{xmp} model in an iterative process for the long-term planning of unit retirements and new builds.

Ultimately, the AURORA^{xmp} modeling process yielded projected market prices for MISO Zone 6, where Hoosier Energy is located. PA then used these market prices to develop the projected dispatch and market revenues for each owned and contracted resources, as well as future candidate resources.

Asset Dispatch Simulation

For Hoosier Energy, PA used our internally developed model to simulate each assets' dispatch that treats the prices of power and fuels stochastically. The model features a Mean Reverting Jump Diffusion (MRJD) process for spot prices. Further, it uses a dynamic program implemented via an American Monte Carlo technique for dispatch, which occurs in 4-hour blocks based on the stochastic behavior of intra-month fuel / and intra-day power prices. Dispatch is performed against a probability array that captures the uncertainty of future prices, i.e. the model does not assume perfect foresight of future prices, and takes into account the physical operating limitations of power generation (i.e. start time, heat rate, VOM, minimum run times, etc.). The resulting output (operations and associated revenues and variable operating costs) represents the expected value of 1,000 individual simulations.

PA utilized this stochastic model in order to:

- Capture actual price volatilities not represented in the AURORA^{xmp} production cost model.
- Model unique plant configurations – examples include cogens, must run requirements, starts/start hour limitations.

Following completion of the AURORA^{xmp} fundamental model, the volatility model was employed.

- The model used a combination of forward power and gas prices in the short term (as applicable) and fundamental prices in the long term as inputs to the process.
- With dispatch against a stochastic price series, the volatility process captured more the granular operating parameters necessary to accurately reflect plant operations.

The following two-step approach was deployed in the model:

1. Detailed the stochastic behavior of intra-month fuel / and intra-day power prices to derive 4-hour block spark spreads, calibrated based on historical data.
2. Implemented Dynamic Programming techniques for optimizing plant operations.

Spot prices for both power and fuel are represented by MRJD price processes. The resulting price volatilities incorporated market, season, and time of day characteristics. Asset dispatch simulations were performed against a probability array that captured the uncertainty of future prices, i.e., the model did not assume perfect foresight of future prices. PA's simulation methodology was based on an independent approach that PA has consistently applied to evaluate multiple types of electric generating assets and asset portfolios for litigation, financing, appraisal, tax, and other purposes. Upon completion of the asset dispatch simulations, the final step in the process was to employ PA's portfolio optimization model.

Portfolio Optimization Modeling

PA's internally developed portfolio optimization model builds potential portfolios of current and future assets that will satisfy any capacity reserve requirements, as well as additional constraints related to capacity and energy exposure to the MISO energy markets.

For Hoosier Energy, the model was customized to consider the existing assets and power supply contracts, as well as the Member Systems' energy and capacity requirements, and calculated the

supply and demand balance associated with those loads and resources. In doing so, the model calculated the capacity and energy shortfalls going forward in time, as assets retire, power supply agreements terminate, and load grows.

The model then constructed supply portfolios consisting of assets and supply contracts as well as potential future resources which Hoosier may add to its system. Additionally, the model considered the possibility of purchasing capacity and energy from the MISO markets on a short-term basis, subject to the pre-defined exposure limits. Ultimately, the model developed potential supply portfolios utilizing all possible combinations of the existing supply portfolio and candidate resources, including the possibility for each candidate resource to reach commercial operations in each year of the study period. In doing so, the model developed up to 1.4 million potential supply portfolios for each scenario, and calculated the projected market revenues from each asset in each potential supply portfolio. Additionally, the model considered the costs of purchasing its energy and capacity requirements from the MISO markets.

The optimization model then incorporated the asset revenues and energy and capacity costs to project the 20-year Net Present Value (NPV) of the power supply revenue requirements for each portfolio, including the costs to serve the Member System loads and the net revenues associated with asset dispatch into the MISO markets. The model produced the NPV associated with each supply portfolio and ranked the portfolios according to least cost NPV. These rankings were then considered for feasibility and risk profile of each portfolio.

Cost and performance data contained in this portion of the IRP update will be used to assemble a set of base case assumptions for use in the modeling process. Supply related assumptions that may vary between the Base Case and sensitivity cases include: (1) fuel prices, (2) natural gas prices, (3) load growth, (4) capital costs and (5) presence of CO₂ emission costs.

5.3 Modeling Assumptions

5.3.1 Risks Inherent in the Modeling Process

Risks are addressed through sensitivity cases in the modeling process. The incorporation of different resource alternatives, market conditions, load growth and future environmental regulations into the modeling process provides a range of scenarios and outcomes. However, it is not possible to predict and capture all risks and the models are simply another tool for management to employ to make resource decisions.

5.3.2 Fuel Price Projections

Hoosier Energy provided estimates of coal prices, which were assumed to remain constant during all months of each year. Natural gas forward prices were developed by PA and vary by month although the charts reflect annual averages. Detailed price projections are found in Appendix D.

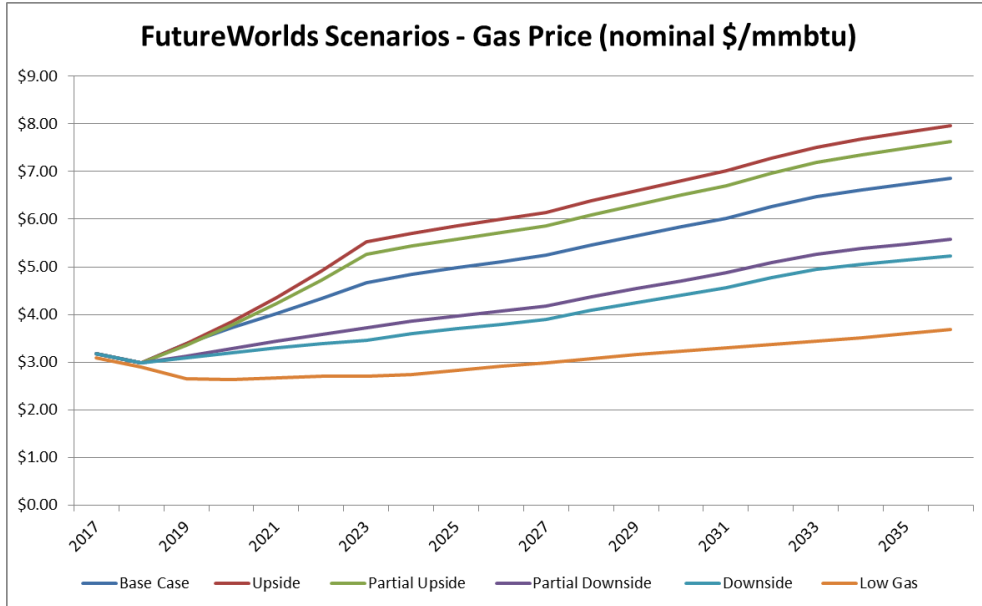


Table 20: FutureWorld Scenario Gas Price Assumptions

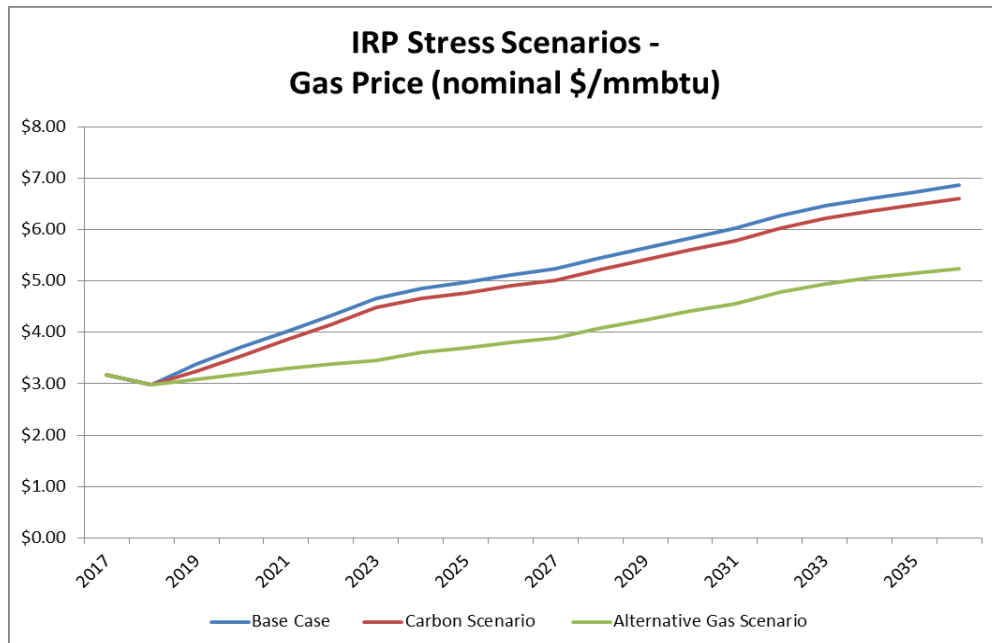


Table 21: IRP Stress Scenario Gas Price Assumptions

5.3.3 Emissions Price Projections

PA Consulting developed emission cost curves used in the production of market price curves, as well as curves for analyses containing prospective future carbon regulations, both of which are provided in Appendix D.

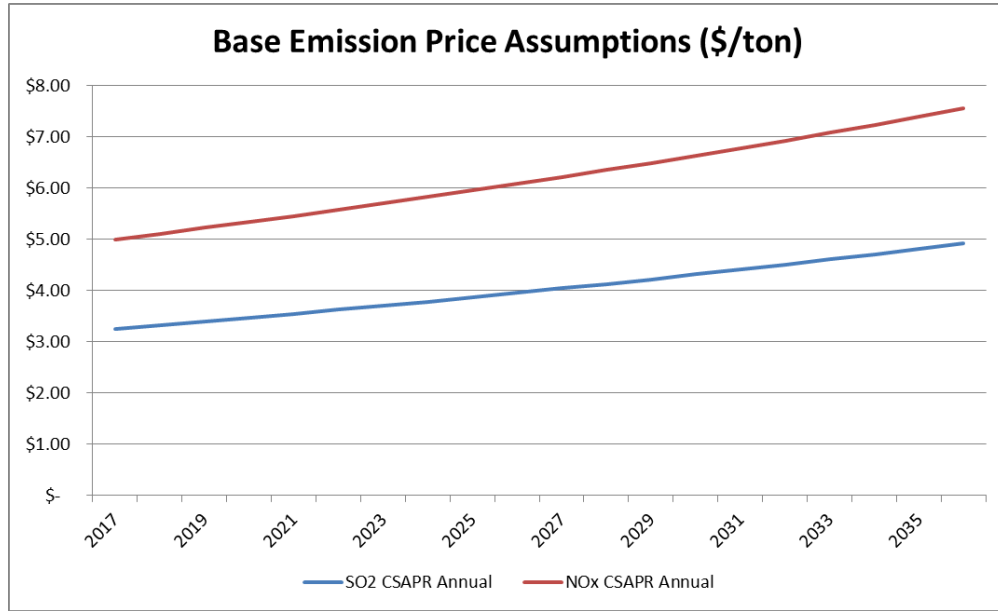


Table 22: Base Emission Price Assumptions

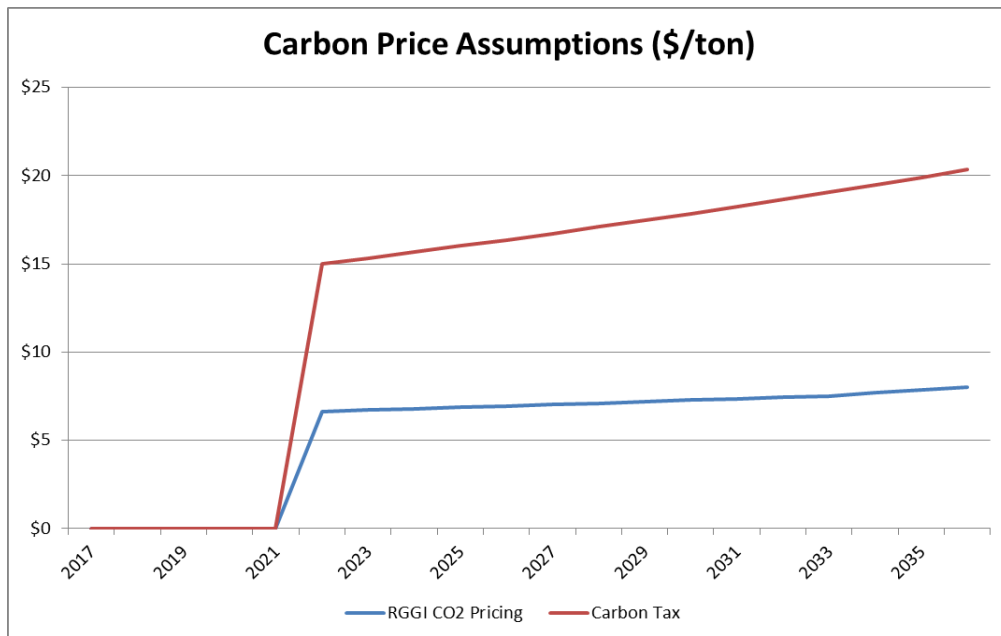


Table 23: Carbon Price Assumptions

5.3.4 Market and Associated Price Projections

PA Consulting supplied annual market energy price projections for on-peak and off-peak power products through 2037, which are provided in Appendix D.

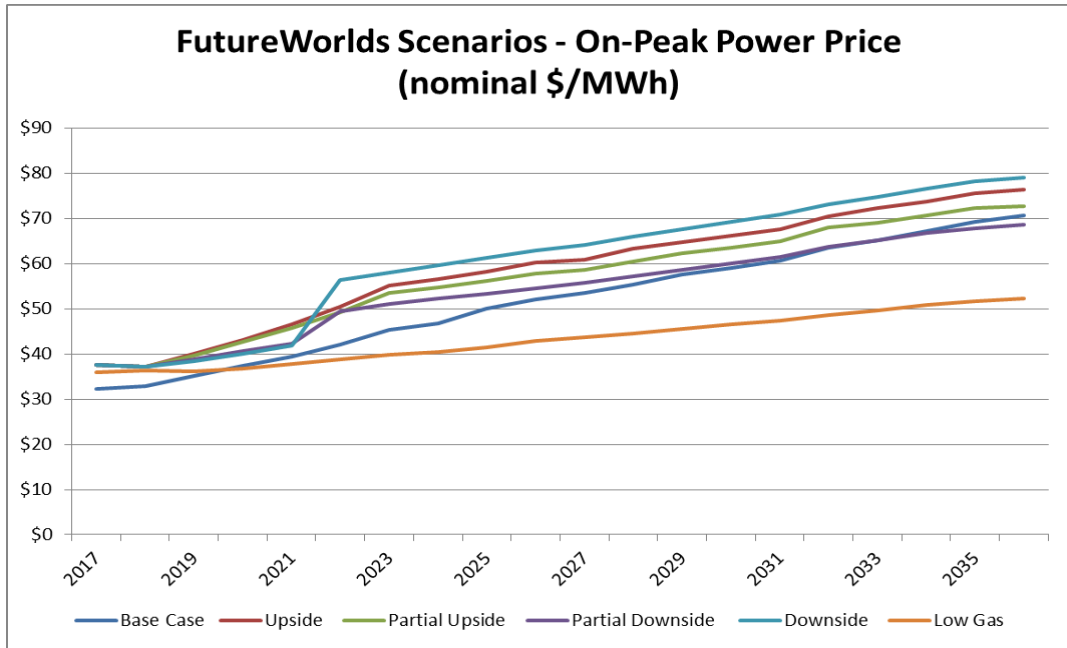


Table 24: FutureWorlds Scenarios - On Peak Power Price Assumptions

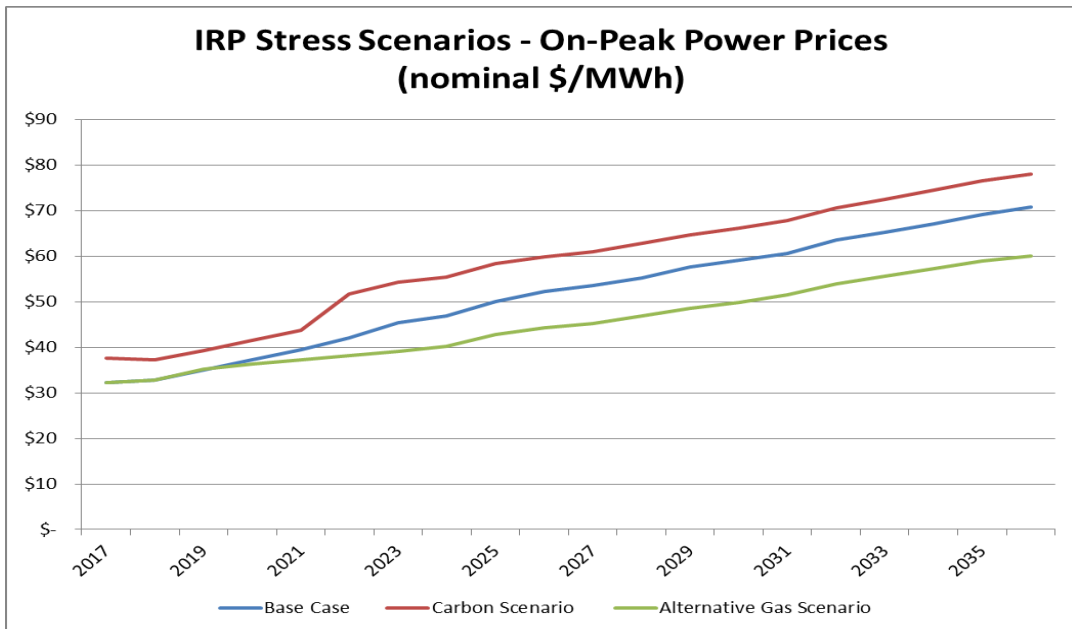


Table 25: IRP Stress Scenario - On Peak Power Price Assumptions

5.4 Global Scenario Development

To evaluate its options, Hoosier Energy contracted with PA Consulting to determine the optimal path to pursue with respect to future resource planning. A primary component of this is Merom's future operations and economics, including the timing and trade-offs associated with its potential retirement. To initiate the process, PA Consulting and Hoosier Energy conducted a day-long workshop to develop key global scenarios. As a result of this workshop, the collaborative efforts of Hoosier Energy and PA Consulting resulted in the construction of a Base Case and four distinct "FutureWorlds" to reasonably bound potential outcomes. These were defined as follows:

1. **Base Case** – The base case is considered to be the most likely future scenario and assumes that future operations are subject to currently forecasted market power, coal, gas, capital and environmental price assumptions as defined in this IRP. It also assumes that demand and energy growth, including DSM program cost and penetration levels remain as forecasted. Additionally, the Base Case assumes that federal and state legislation, including environmental regulations, does not vary significantly from that in place today. It should be noted that the Base Case does not assume implementation of carbon regulations during the forecasted period.
2. **Coal Upside** - Strong economic growth, rising per capita income, new industrial/technology demand, and rural community growth contribute to cooperative growth (including load growth) and limited consumer/grid defection. Advanced Metering Infrastructure (AMI) expansion enhances consumer relationships. Consumers give deference to utility economies of scale, contributing to expanded EV use and low distributed generation penetration.

Meanwhile, societal pressure on coal/emissions is limited which delays environmental regulations, contributes to CCS technology breakthrough, and decreases coal prices (despite the higher demand for coal...regulations trump demand). Anti-fracking gas regulations are instituted and Marcellus/Utica pipeline build out is delayed which contributes to increasing natural gas prices. High capital costs and diminishing renewable demand lead to limited new build wind/solar activity. The MISO capacity market is increasingly competitive with high price outcomes (aided by the retail choice in Illinois and Michigan) and regional transmission build out is accelerated (helping Hoosier's generator vs load power basis discrepancy). Cyber-attacks on the U.S./MISO electric grid result in short term price spikes which improve generator margins, but also result in long term operating expense increases for Hoosier.

3. **Partial Upside** - Weak economic growth, slowing per capita income, declining industrial/technology demand, and urban migration contribute to cooperative growth declines (including load growth) and notable consumer/grid defection. Stagnant AMI expansion diminishes consumer relationships, leading to limited EV growth and high distributed generation penetration.

However, societal pressure on coal/emissions is limited which delays environmental regulations, contributes to CCS technology breakthrough, and decreases coal prices (despite the higher demand for coal, regulations trump demand). Anti-fracking gas regulations are instituted and Marcellus/Utica pipeline build out is delayed which contributes to increasing natural gas prices. High capital costs and diminishing renewable demand lead to limited new build wind/solar activity. The MISO capacity market is

increasingly competitive with high price outcomes (aided by the retail choice in Illinois and Michigan) and regional transmission build out is accelerated (helping Hoosier's generator vs load power basis discrepancy). Cyber-attacks on the U.S./MISO electric grid result in short term price spikes which improve generator margins, but also result in long term cost increases for Hoosier.

4. **Coal Downside** - Weak economic growth, slowing per capita income, declining industrial/technology demand, and urban migration contribute to cooperative growth declines (including load growth) and material consumer/grid defection. Stagnant AMI expansion diminishes consumer relationships, leading to limited EV growth and high distributed generation penetration.

Meanwhile, societal pressure on coal/emissions heightens which accelerates environmental regulations, limits investment in CCS, and increases coal prices (despite the lower demand for coal...regulations trump demand). New regulations on gas are limited and Marcellus/Utica pipeline build out is accelerated which contributes to sustained low natural gas prices. Low capital costs and increasing renewable demand lead to increased new build wind/solar activity. The MISO capacity market auction provides low prices, which do not incent siting of new capacity within the region. Similarly, regional transmission buildout is developed at a slower pace than in the Upside scenarios. There are no cyber-attacks on the U.S./MISO electric grid.

5. **Partial Downside** - Strong economic growth, rising per capita income, new industrial/technology demand, and rural community growth contribute to cooperative growth (including load growth) and limited consumer/grid defection. AMI expansion contributes to enhancing consumer relationships. Consumers give deference to their utility's economies of scale, which contributes to expanded EV use and low distributed generation penetration.

However, increased societal pressure on coal/emissions accelerates environmental regulations, limits investment in CCS, and increases coal prices (despite the lower demand for coal...regulations trump demand). New regulations on gas are limited and Marcellus/Utica pipeline build out is accelerated which contributes to sustained low natural gas prices. Low capital costs and increasing renewable demand lead to increased new build wind/solar activity. The MISO capacity market auction provides low prices, which do not incent siting of new capacity within the region. Similarly, regional transmission buildout is developed at a slower pace than in the Upside scenarios. There are no cyber-attacks on the U.S./MISO electric grid.

5.4.1 Quantitative Assumptions

PA Consulting developed quantitative assumptions for each of the four FutureWorld scenarios, as well as for the Base Case scenario. These assumptions are provided in Table 26 below.

	Coal Downside	Partial Downside	Base Case	Partial Upside	Coal Upside
HH Gas Price (\$/MMBtu)	(\$1.00) lower than Base, phased in beginning 2019	(\$0.75) lower than Base, phased in beginning 2019	\$3.29 (\$2017)	+\$0.75 higher than Base, phased in beginning 2019	+\$1.00 higher than Base, phased in beginning 2019
MISO Coal Prices (\$/MMBtu)	Long term ILB costs: 10% higher than Base	Long term ILB costs: 7.5% higher than Base	\$1.71 (\$2017)	Long term ILB costs: 7.5% lower than Base	Long term ILB costs: 10% lower than Base
MISO Load Growth	0.1% CAGR	+1.0% CAGR	+0.7% CAGR	(0.3%) CAGR	+1.0% CAGR
Capital Costs	(20%) lower than Base	(10%) lower than Base	-	+10% higher than Base	+20% higher than Base
MISO Renewable Builds	Double Zone 6 & 7 economic additions	Double Zone 6 & 7 economic additions	-	Remove Zone 6 & 7 economic additions	Remove IRP related and Zone 6 & 7 economic additions
Environmental	\$15/ST (2022)	RGGI-level (2022)	No Carbon	No Carbon	No Carbon

Table 26: FutureWorlds Quantitative Assumptions

Although the above covers a broad spectrum of future outcomes, Hoosier Energy and PA Consulting determined that there was a need for an additional scenario (Low Gas) and a need for a stress case applied to each of the six scenarios (the Base Case, the 4 FutureWorld cases and the Low Gas case).

The new scenario stresses natural gas prices to recognize the potential for continued robust domestic production of natural gas and resulting low prices. This scenario, the Low Gas scenario, incorporates NYMEX Henry Hub forward prices (as of July 2017) through 2029, and then prices remain flat in real dollars thereafter. A graphical comparison between natural gas cost assumptions incorporated into various scenarios is provided in Table 20.

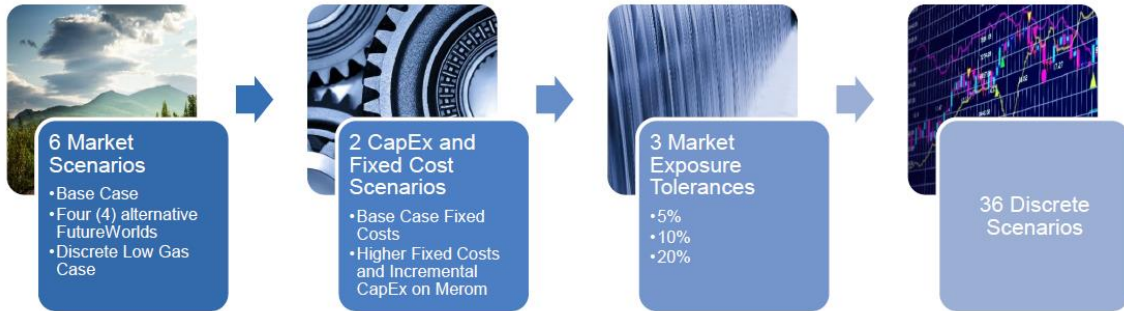
The stress case assumes additional expense in mid-2020s and increased escalation of annual fixed O&M and capital expenses. This case is useful to gauge the potential impact of an unexpected increase in the operating cost of existing generation.

Hoosier Energy’s tolerance for market demand and energy exposure also impacts the timing and economics of the optimal compliance plan. PA Consulting worked with Hoosier Energy to define an appropriate risk tolerance level and conduct analysis using tolerance bands. The tolerance bands were defined as:

- High tolerance: +/- 20% above forecasted member load

- Base tolerance: +/- 10% above forecasted member load
- Low tolerance: +/- 5% above forecasted member load

This results in a total of 36 discrete scenarios:



5.4.2 Future Resource Options

In conducting its initial analysis, PA Consulting assessed a number of supply-side options with respect to Merom’s long-term operational and economic feasibility. The cost and performance characteristics for each of these potential supply-side alternatives are included in Appendix C. The supply-side resources considered were produced through a collaborative effort between Hoosier Energy and PA Consulting. These resources passed the screening analysis and were the best future resource options available. As depicted in Table 27 below, the options considered were:

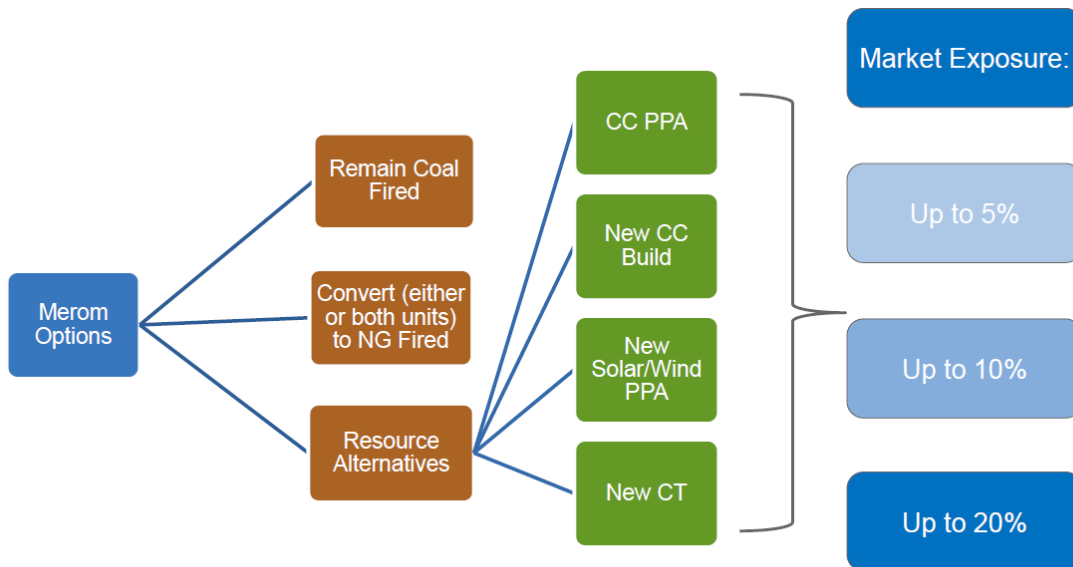


Table 277: Summary of Future Resource Options

It should be noted that the Wind PPA identified as a viable supply-side candidate in Section 4.6 was also considered in this analysis, but was never selected due to the Solar PPA option being more economic.

Based upon its industry expertise, PA Consulting provided operational and cost information related to the identified capacity replacement options. These assumptions are provided in Table 28.

Option	Capital (2017\$/kW)	Net Winter Capacity (MW)	Heat Rate (Btu/kWh)	VOM (2017\$/MWh)	Annual FOM (2017\$/kW)
Convert to NG	550	495	10,549	1.82	20.00
Holland CC Conversion (2x1 to 3x1)	734	843 +63 duct firing	7,170	4.19	14.23
Lawrence CC Conversion (2x1 7FA)	860	655	6,840	3.26	14.23
Merom CC (1x1 H Class)	1,197	464	6,568	3.05	17.35
New CT (H Class)	772	205	9,707	7.65	8.10

Table 28: Merom Capacity Replacement Options

In addition to the above assumptions provided by PA Consulting, Hoosier Energy provided the operational and cost assumptions for a Combined Cycle PPA, a Wind PPA and Solar PPA based upon its discussions with developers over the most recent 12 – 18 month period. These assumptions are provided in Appendices C and D.

5.5 Portfolio Optimization Results

PA Consulting evaluated 36 discrete scenarios to examine the economics trade-offs of future resource options. These scenarios included a combination of the six described market scenarios (Base Case, four FutureWorlds and Low Gas scenario), the High Capex stress case and varying market exposure tolerance levels (5%, 10% and 20%). The results of the scenarios are summarized in Table 29.

In one-half of the scenarios (18), the PA analysis indicates that Merom remains economic through 2040. This includes all variations of the Base Case, Coal Upside and Partial Upside scenarios. In these scenarios, the model selects a PPA based upon the characteristics of a NGCC early in the planning horizon to meet new capacity requirements resulting from expiring purchased power contracts and forecast increased load requirements. Later in the planning horizon, the model selects solar PPAs to meet forecast increasing load.

Not surprisingly, given today’s gas and power market environment, the remaining scenarios indicated that Merom could become challenged economically prior to 2040. These scenarios include the Partial Downside, Downside and the Low Gas scenario. The results are also contingent upon higher than expected capital expenditures, higher coal prices, lower gas prices and new carbon regulations included within those scenarios.

By design, models select specific years to add or subtract a generating resource based strictly upon economic factors. That determination is highly dependent upon the many assumptions made in the model, including the amount and timing of significant expenditures, fuel assumptions, load growth, market price projections, environmental regulations, etc. In reality, any decision related to current or future resources will require additional analysis of factors and potential options. Therefore, the model’s selection of a specific year should be considered a guide and indicates the need for additional analysis.

Market Case	Market Tolerance	Total NPV	CC1	Solar 1	Solar 2	CC PPA 1	Merom Decision Point
Base Case	5%	(\$5,351,957)	2040	2033		2024	2040+
	10%	(\$5,009,262)	2040	2033		2024	2040+
Upside	5%	(\$5,427,383)	2039	2027	2034		2040+
	10%	(\$5,390,261)	2040	2025	2034		2040+
Partial Upside	5%	(\$5,400,700)	2039	2029	2034		2040+
	10%	(\$5,368,055)	2040	2025	2034		2040+
Downside	5%	(\$5,089,265)	2025	2039	2040		2025
	10%	(\$5,061,942)		2039	2040		2024
Partial Downside	5%	(\$5,128,613)	2034	2033		2026	2034
	10%	(\$5,153,453)	2034	2033		2025	2034
Low Gas	5%	(\$4,332,771)	2024	2039		2024	2024
	10%	(\$4,299,381)	2024	2039		2024	2024

Table 29: Summary of Base Case and FutureWorld Results

5.6 Integrated Resource Plan – Supplemental Modeling

The FutureWorlds analysis described above incorporates the load forecast from the 2015 PRS, as that was the most recent available load information. Subsequent to the modeling of the FutureWorlds scenarios, Hoosier Energy completed and released its updated load forecast – the 2017 PRS. Development of the PRS is described in Section 2 of the IRP. As a result, PA was asked to conduct additional modeling using the latest load forecast. An update of the four FutureWorlds scenarios was considered, however, given the differential in Summer Peak Demand between the two PRS documents is only approximately 20–30 MW, it was determined that the findings were unlikely to be different. Therefore, FutureWorlds modeling was not updated with new load information from the 2017 PRS.

Although PA advised that the incorporation of load information from the 2017 PRS was unlikely to change the results of the modeling, Hoosier Energy elected to use the 2017 PRS in the following additional modeled scenarios, which were designed to provide additional information regarding the FutureWorlds results by focusing on the individual parameters that PA Consulting had determined has the greatest impact on the long-term economic viability of current resources.

1. Base Load – Using Base-Upper Normal load scenario from 2017 PRS

- a. Base Case – same assumptions as FutureWorlds Base Case scenario, although load was updated to reflect 2017 PRS.
 - b. Alternative Gas Scenario – Gas prices 20% lower than included in the Base Case which, although lower than the Base Case assumptions, provides a higher forward price than was included in the FutureWorlds Low Gas scenario and provides Hoosier Energy with a midpoint forecast with which to test current resource economic viability.
 - c. Carbon Scenario – RGGI-level prices beginning in 2022, which increases Merom’s dispatch cost relative to alternative resources and tests its ability to operate on an economic basis in that higher-cost environment.
2. Low Load - Using Low Economic load scenario from 2017 PRS
 - a. Base Case – same assumptions as FutureWorlds Base Case scenario, although load was updated to reflect 2017 PRS.
 - b. Alternative Gas Scenario - Gas prices 20% lower than included in the Base Case which, although lower than the Base Case assumptions, provides a higher forward price than was included in the FutureWorlds Low Gas scenario and provides Hoosier Energy with a midpoint forecast with which to test current resource economic viability.
 - c. Carbon Scenario - RGGI-level prices beginning in 2022, which increases Merom’s dispatch cost relative to alternative resources and tests its ability to operate on an economic basis in that higher-cost environment.
3. Merom Capital Costs 10% higher than in Base Case – stresses Merom’s forecasted Capital Cost expenditures to determine if additional long-term investment in the facility is warranted.
 4. Renewables Costs 10% lower than in Base Case – Lowers the prices of the Solar and Wind PPA assumptions to determine current resource economic viability in a low-cost renewables market.

Each individual scenario was run using market tolerance levels of both +/- 5% and +/- 10%. Table 30 shows the most economic expansion plans selected for each of the scenarios. In all cases, the scenarios where Merom remains on-line through 2040 are less expensive. The difference is roughly 6% for the Base Case, Base Load scenario. The lowest differential is 2% under the Low Load, Carbon scenario and the highest differential is 8% under the Base Load, High Capital Cost scenario.

Load Case	Market Case	Market tolerance	Total NPV	CT1	CT2	Solar 1	Solar 2	Solar 3	
Base Load	Base Case	5%	(\$5,147,211)	2024		2030	2036	2037	
		10%	(\$5,152,587)	2024		2030	2036	2037	
	Low Gas	5%	(\$5,034,535)	2024		2030	2036	2037	
		10%	(\$5,043,859)	2024		2030	2036	2037	
	Carbon	5%	(\$6,092,583)	2024		2030	2036	2037	
		10%	(\$6,103,799)	2024		2030	2036	2037	
	High Capital Costs	5%	(\$5,159,821)	2024		2030	2036	2037	
		10%	(\$5,165,196)	2024		2030	2036	2037	
	Low Renewable Costs	5%	(\$5,108,509)	2024		2030	2036	2037	
		10%	(\$5,113,268)	2024		2030	2036	2037	
	Low Load	Base Case	5%	(\$4,614,306)			2035	2036	2037
			10%	(\$4,567,523)			2035	2036	2037
Low Gas		5%	(\$4,503,722)			2035	2036	2037	
		10%	(\$4,474,066)			2035	2036	2037	
Carbon		5%	(\$5,387,417)			2035	2036	2037	
		10%	(\$5,365,869)			2035	2036	2037	
High Capital Costs		5%	(\$4,614,306)			2035	2036	2037	
		10%	(\$4,567,523)			2035	2036	2037	
Low Renewable Costs		5%	(\$4,580,876)			2035	2036	2037	
		10%	(\$4,533,491)			2035	2036	2037	

Table 30: Economic Expansion Plan for Base Load and Low Load Scenarios

5.7 Demand-Side Resource Analysis

The expected base level impact of demand-side resource programs for the 20-year IRP time horizon have been incorporated into the load forecast employed by Hoosier Energy in this IRP. This forecast is based upon the expected demand-side participation captured in Hoosier Energy’s 2017 PRS. The number of forecasted participants, current program costs, projected energy program savings and projected Winter and Summer Demand savings that are included in the load forecast are provided in Appendix G.

DSM Assumptions

Assumptions for current DSM programs, including effective useful life, annual energy and demand savings, measure cost and incentives, is found in Appendix F. To conduct an assessment of potential additional DSM measures, PA collaborated with Hoosier Energy to develop a Levelized Cost of Energy (LCOE) analysis. Each DSM measure was grouped into certain DSM portfolios, and the collective potential of the portfolio to reduce the cost to serve load was projected.

<u>DSM Portfolio #</u>	<u>End Use</u>	<u>Measure Name</u>
1	Residential Lighting	
	Lighting	LED Lighting (Standard)
	Lighting	LED Lighting (Specialty)
2	LED Security Lighting	
	Lighting	LED Security Lights
3	Appliance Recycling	
	Appliances	Refrigerator Recycling
	Appliances	Freezer Recycling

4	Residential HVAC (Single Family)	
	HVAC (Equipment)	Heat Pump (15 SEER)
	HVAC (Equipment)	Heat Pump (16 SEER)
	HVAC (Equipment)	Heat Pump (17 SEER)
	HVAC (Equipment)	Heat Pump (18 SEER)
	HVAC (Equipment)	Heat Pump (15 SEER) E. Furnace Replacement
	HVAC (Equipment)	Heat Pump (16 SEER) E. Furnace Replacement
	HVAC (Equipment)	Heat Pump (17 SEER) E. Furnace Replacement
	HVAC (Equipment)	Heat Pump (18 SEER) E. Furnace Replacement
	HVAC (Equipment)	Geothermal Heat Pumps
	HVAC (Equipment)	Mini Split Heat Pump (16 SEER)
	HVAC (Equipment)	Mini Split Heat Pump (17 SEER)
	HVAC (Equipment)	Mini Split Heat Pump (18 SEER)
	HVAC (Equipment)	Mini Split Heat Pump (19 SEER)
	HVAC (Equipment)	Mini Split Heat Pump (20 SEER)
5	Other Savings	
	Cross-Cutting	Energy Kits A
	Cross-Cutting	Energy Kits B
6	C&I Energy Efficiency	
	Lighting	Traditional C&I Projects Average Savings
	Lighting	Direct Install Project Average Savings
	Lighting	Agricultural Lighting
	Lighting	Occupancy Sensors
	Motors	NEMA Premium Eff. Motor > 10 HP
	Motors	NEMA Premium Eff. Motor < 10 HP
	Motors	VSD on Motors
	HVAC	Programmable Thermostat
	HVAC	Heat Pump (11.3 EER, COP 3.4)
	HVAC	Air Conditioner (12 EER)
7	Load Control	
	Water Heating	<80 gallon water heater control
	Water Heating	>80 gallon water heater control
	HVAC	AC Control
	HVAC	ASHP Control
	HVAC	Geothermal HP Control
	Water Heating	Heat Pump Water Heaters

Levelized Cost of Electricity (LCOE) Analysis

For each measure within each program, the LCOE was calculated in real \$2024 dollars. The analysis assumed that the Measure Costs associated with each measure were originally provided in real \$2016.

Each measure's cost was escalated to nominal dollars in 2024 using an assumed 2.2% annual inflation estimate. The annual costs for each measure were the 2024 Measure Cost in 2024,

followed by zero costs for the remainder of the measure's Effective Useful Life. Estimates for the annual energy savings for each measure were developed.

The LCOE of each measure was calculated using the annual costs and the annual energy savings for the term of each measure's Effective Useful Life. The LCOE analysis assumed a 7.2% discount rate. Each measure's LCOE provides an "at a glance" estimate of the cost and benefits of the measure, which can be compared against market energy prices to gauge the cost effectiveness of each measure.

Estimated Penetration Rates

PA worked with Hoosier Energy's DSM team – those responsible for managing the DSM programs – to develop an estimate of the potential increased penetrations of each measure. Using the current and projected participant counts of each measure, PA calculated additional participants for each measure. The growth in participant counts was limited to one-half of the annual energy growth forecast. For example, if the annual growth was 1%, then the number of additional participants was limited to 0.5% growth above the current participation level.

Each measure's additional energy savings were projected by multiplying the per-measure energy savings by the number of additional participants for each year. Each measure's costs were projected by multiplying the per-measure cost by the number of additional participants for each year. The analysis assumed that measure costs were incurred in the first year of each additional participant's participation, followed by zero costs incurred for the remainder of the measure's Effective Useful Life.

For measures with shorter lives than the study period of 2024-2040, each participant was assumed to renew the measure using the current year's measure costs in nominal dollars, with the corresponding annual energy savings extended through the measure's Effective Useful Life. In cases where a measure's life extended past the study period end, the annual energy savings were extended and incorporated into the NPV of the potential increased penetration.

Each measure's aggregated energy savings were multiplied by the projected Base Case market pricing used in the IRP analysis. The aggregate costs of each measure and the aggregate market energy cost savings were discounted to \$2024 using a 7.2% discount rate, resulting in an estimated NPV impact to the preferred IRP portfolio. This allows estimating the value of adopting a given DSM portfolio within its preferred portfolio.

Certain measures did not have available data related to the current participation counts, and thus it was not possible to project the increased penetration associated with those measures; however, the LCOE analysis was completed for those measures.

Load Control Analysis

Portfolios one through six were modeled as energy savings portfolios, as their ability to achieve peak demand reductions are not material. Portfolio eight was modeled as a demand reduction portfolio as the measures are expected to achieve no or immaterial energy savings; however, with no participant data for all but one of the portfolio eight measures, it was not possible to project the NPV impact associated with those measures. The levelized cost analysis of these measures was completed, though rather than a levelized cost of energy, a levelized cost of capacity analysis was completed.

The Heat Pump Water Heater measure – though originally a part of portfolio four – was included as a load control measure, as it is projected to have no or immaterial energy savings. In addition to the LCOE analysis, the increased penetration analysis was completed for this measure. The analysis found that due to having an LCOE of approximately \$213/kW-year, the measure is not projected to be cost effective and would increase costs of the preferred IRP portfolio.

The cases that included the additional DSM programs did not contain enough avoided energy or capacity to defer or avoid a new generic resource. The portfolio construction, resource penetration levels and cost assumption information is included in Appendix G.

5.8 Preferred Plan Based on Resource Planning Criteria

The preferred resource plan selected is the Base Load/Base Case, including a 10% market tolerance level. As discussed in Section 1.3, Hoosier Energy’s preferred Integrated Resource Plan meets three critical resource planning criteria.

1. The plan is low cost among supply alternatives.
2. The plan assures high reliability with respect to generation and delivery of wholesale power; and
3. The plan is consistent with maintaining a profile of low market and business risks.

The capacity expansion plan (Table 15) demonstrates sufficient capacity resources for the short-term planning horizon. A summary of the preferred resource plan resulting from the Base Case of the Supplemental Modeling is summarized in the following table. Although not shown in this table, Hoosier Energy, in conjunction with the Member Systems, will continue to provide cost effective demand response and energy efficiency programs.

Year	Retirements	Additions
2018		Meadow Lake Wind (25 MW); Orchard Hills LFG (16 MW)
2019	Story County PPA (25 MW)	
2020		Meadow Lake Wind (50 MW); Solar PPA (100 MW)
2021		Solar PPA (100 MW)
2022		
2023		
2024	Duke Energy PPA (100 MW)	Combustion Turbine (205 MW)
2025		
2026	Duke Energy PPA (50 MW)	
2027		
2028	Clark-Floyd LFG (4 MW)	
2029	Rail Splitter PPA (25 MW)	
2030		
2031		
2032	Dayton Hydro (4 MW)	
2033		
2034		
2035		Solar PPA (200 MW)
2036		Solar PPA (200 MW)
2037		Solar PPA (200 MW)
Total MW	208	1,096

Table 31: Hoosier Energy Preferred Integrated Resource Plan

5.8.1 Least Cost

While Table 31 presents the lowest cost resource plan under the Base Case, Hoosier Energy may elect to pursue other cost effective and/or advantageous resources. This could include market products, joint development of supply-side resources, power purchase agreements, renewables, and/or additional demand-side management.

A balanced portfolio of utility owned generation (baseload, peaking and intermediate), power purchases and sales, renewables, market contracts, and demand-side resources diversifies risk in the event load or market conditions change.

5.8.2 Reliability

This IRP addresses reliability in three ways. As a load-serving entity, Hoosier Energy has an obligation to serve member cooperatives. A diverse portfolio of resources assures Hoosier Energy can reliably and economically provide wholesale power to member-owned cooperatives. The IRP also accounts for planning reserves as established by RFC and the MISO and forced outage rates based upon the actual operating history of Hoosier Energy's generation resources. Reserves are a necessary addition to the resource requirement plan and are used to offset the effects of contingencies that arise either because of generation unavailability or changes in load (e.g. weather effects, customer mix and usage). Additionally, Hoosier Energy continues to invest in the transmission system to accommodate growth and ensure reliable service. Membership in the regional transmission organizations (MISO and PJM) allows reliance upon the RTOs' reliability tools, such as the state estimator, real-time contingency analysis and regional outage coordination. In addition, membership in the RTOs allows management of generation facilities that are connected to other RTO utilities but still benefit Hoosier Energy.

5.8.3 Risk

The preferred plan, which includes more renewables and potential gas-fired generation, in combination with Hoosier Energy's current resource portfolio – a diverse mix of owned resources, long-term purchases, renewables, demand-side management and short-term power market purchases and sales – maintains a low market and business risk profile. While the current wholesale market provides short-term economic opportunities, that is unlikely to be the case for the long-term. Therefore, additional resources (PPAs or owned) will likely be required in the future. The risk mitigation technique of joint ventures for owned resources, which allow for the sharing of risks and reduce overall costs, may be an important component of future resource strategy.

5.8.4 Flexibility

As stated in the Executive Summary, the goal is to develop a Plan that is low risk, reliable and cost effective. A secondary goal is a Plan that is flexible to enable cost effective responsiveness to changing business circumstances. Given the lack of required new resource additions contemplated, the preferred plan will enable Hoosier Energy to react to and adapt to load forecast changes, legislative and regulatory mandates, and the potential development or advancement of new technologies.

Environmental legislation and regulations are a significant driver in the development of the IRP. These regulations affect cost assumption tradeoffs between the type, quality and availability of fuel burned and the allowable emissions levels of existing and future generating resources. Therefore,

the IRP must not only comply with existing regulations but also allow Hoosier Energy to be flexible enough to adapt to further emission restrictions.

The ability to pursue alternative strategies depending upon regulatory and market environments is an important component of the preferred plan. The Plan use of owned resources and long and short-term purchases and sales not only reduces risk, but also provides the flexibility necessary to respond to changing market conditions.

5.8.5 Greatest Influences on the Preferred Resource Plan

A resource plan is inherently uncertain and major cost categories require risk management. The following is a list of these major categories:

- Fuel costs
- Interest rates
- Future environmental regulations
- LMP market changes
- Regional power requirements
- Member system growth
- Industrial growth
- Inflation rates
- Transmission pricing
- New technologies

Some of these are briefly discussed below.

- The variable with the prospective greatest influence on the preferred resource plan is future natural gas price expectations. The Low Gas scenario provides an outcome in which gas-fired resources become more economic in the mid-2020s.
- The PRS includes seven different forecasts (base, high-economic, low-economic, base-upper normal weather, base-lower normal weather, base-mild weather and base-extreme weather) to establish reasonable boundaries for expected load growth.
- The preferred resource plan is based on an estimated MISO reserve margin of 8.40% as its minimum standard of reliability.
- The Plan considers the potential for future environmental regulations, including restrictions on other pollutants such as carbon, waste water and coal combustion residuals. No financial benefits are assumed because of the sale of emissions credits to other utilities.

5.8.6 The Present Value of Revenue Requirement of the Preferred Plan

As discussed in the Executive Summary, one of the primary goals of the IRP is to develop a plan that economically meets member requirements. The Net Present Value of the Preferred Plan is \$5.2 billion, which is the base plan with the lowest NPV. The NPV was calculated using a discount rate of 5%.

5.8.7 Consideration of Non-Traditional Supply

As detailed in Sections 3 and 4 of this Plan, Hoosier Energy has implemented non-traditional technologies, such as methane gas-fired renewable resources and demand-side management

through both demand response and energy efficiency, and supporting non-utility generation. In the past ten years, Hoosier Energy has built and operates several landfill gas generation facilities, 10 solar facilities and entered into PPAs for both hydro and wind generation. Hoosier Energy remains committed to pursuing additional renewable resources under its Renewable Energy Program.

With respect to energy efficiency and demand response, Hoosier Energy continues to collaborate with Member Systems to provide a variety of DSM programs to their retail members. These efforts lower demand and energy consumption and reduce retail member electricity costs through these programs wherever economically feasible.

5.9 Development of the Preferred Plan

The goals of the IRP are to achieve low power supply cost for member systems while maintaining a low market and business risk profile and ensuring a high degree of reliability. This IRP considered a variety of generation options (supply-side) and consumer usage modification (demand-side) alternatives to develop an appropriate blend of resources to minimize overall system cost.

An assessment of Hoosier Energy's current generation capacity and purchased power agreements is found in Section 3.1. This section also provides additional detail on environmental, transmission and commodity forecasts. Sections 3.2 Demand-side Resource Assessment, 4.2 Future Demand-Side Resource Assessment and 4.3 Future Supply-Side Resource Assessment outline the demand and supply-side options that are available to Hoosier Energy to meet future demand. Section 4 includes the resource screening analysis for demand and supply-side options. Based on this analysis, the most economical resources were considered in the Hoosier Energy plan.

5.9.1 Effects of the Preferred Plan on Revenue Requirements

For a cooperative, the impact on revenue requirements is one of the primary considerations when determining the proper mix of resources. Hoosier Energy's projects revenue requirements to be basically flat from the period of 2018 – 2023. The PA modeling results shows an annual increase in the generation component of revenue requirements of 2.4 percent for the period of 2024 - 2037. Hoosier Energy will continue to strive to find additional cost and operational efficiencies to minimize the impact of increasing revenue requirements.

5.9.2 Hoosier Energy's Ability to Finance New Resources

Hoosier Energy is rated A by Standard & Poor's and A2 by Moody's as of February 2018. Both ratings are investment grade and allow for ready access to public and private capital at market-based rates. Hoosier Energy anticipates maintaining this credit quality in the future. Therefore, adequate capital resources are available to finance the construction or acquisition of new resources recommended by this Plan.

5.10 Conclusion

Assuming forecasted load growth, Hoosier Energy has a need for additional capacity in the mid-2020s. The optimal online date for new capacity, as well as the most economic type of resource, depends upon the assumptions in the various scenarios, such as member load growth, environmental regulations and market conditions.

Hoosier Energy will pursue a plan based upon the following strategies:

1. Under Base Case assumptions, Merom is expected to remain economic thru the planning horizon. Hoosier Energy will continue to monitor and analyze potential environmental regulations and market economies that may impact intermediate and long-term operations.
2. Continued implementation of cost-effective Demand Side Management resources in conjunction with Hoosier Energy members.
3. Pursuit of cost-effective, renewable resources that provide fuel and resource diversity and help hedge against future environmental regulation risk.
4. Under all market cases (base, low gas, carbon, high capex and low renewable) with the base load forecast, the model recognizes a need for inexpensive, new capacity and selects a gas-fired combustion turbine in the mid-2020s. Under the low load cases, the resource need does not occur until later in the planning horizon and the model favors solar resources.