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# Hoosier Energy REC
# 2014 Integrated Resource Plan
# Volume I: Main Report

## Redacted Version

**November 2014**

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# Table of Contents

# List of Tables

# Section 1: Introduction

# 1 Introduction

This *2014 Integrated Resource Plan* (the Plan or the IRP) is submitted by Hoosier Energy Rural Electric Cooperative Indiana 106 Statewide ("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 three volumes. Volume I contains the executive summary, the peak demand and energy forecasts, and the resource assessment, as required by the Rule. Volume II contains the appendices with information required under the Rule.

The IRP contains six subsections. The first section (Section 1.0) provides an overview of Hoosier Energy and the Hoosier Energy member systems. The second subsection (Section 2.0) summarizes Hoosier Energy's energy and demand forecasts and the methodology used to develop the forecasts. The third subsection (Section 3.0) describes Hoosier Energy's existing assets, including supply-side assets such as power plants, power purchase and power sales and demand-side assets. The fourth and fifth subsections (Section 4.0 and 5.0) review new resources (both supply-side and demand-side) and the integration of those resources, respectively. Section 6.0 contains the Integrated Resource Plan.

## 1.1 Hoosier Energy REC 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**

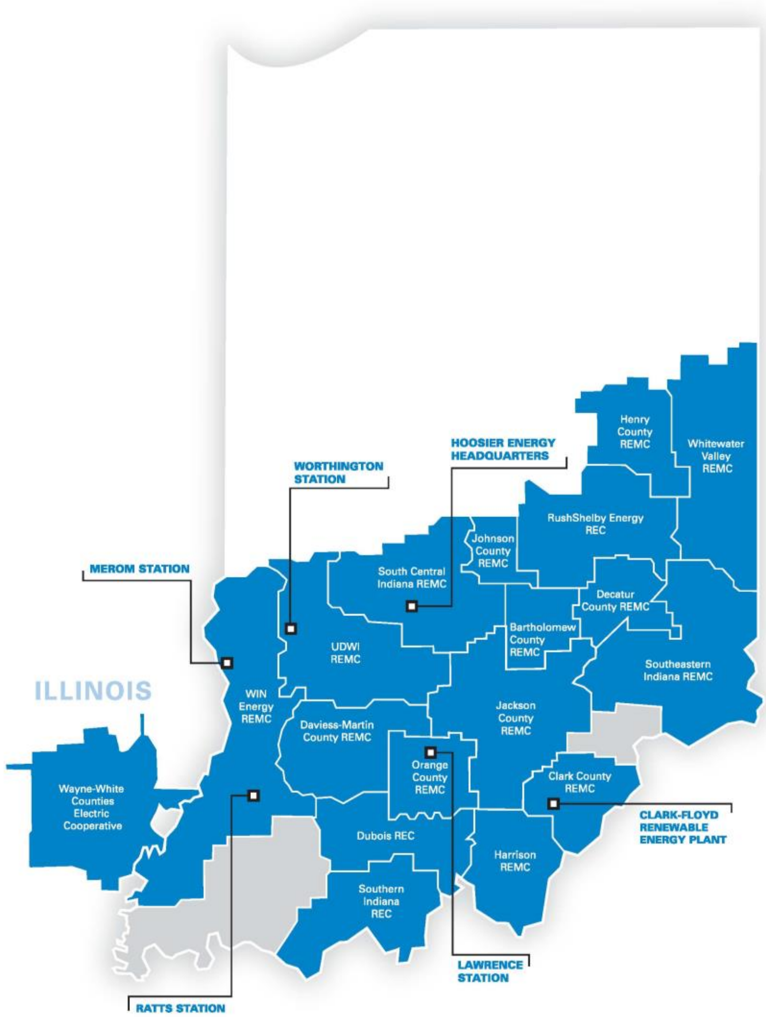
Hoosier Energy began supplying power to Wayne-White Counties Electric Cooperative (WWCEC) on January 1, 2011.

### *1.1.2 Location and Service Territory Characteristics*

Hoosier Energy's headquarters facility is located on State Road 37, just north of Bloomington, Indiana. Hoosier Energy operates power plants in Petersburg, Merom, Worthington, Lawrence County, Indiana and Beecher City, Illinois (detailed further in Section 3.1.1) and has transmission crews stationed in Bloomington, Seymour, Rushville, Worthington, Petersburg, Napoleon, and English.

The approximate boundaries for the Indiana portion of Hoosier Energy's service territory are as follows:

NORTH – A line drawn across central Indiana from a point south of Terre Haute east to the counties immediately south of Indianapolis (Morgan, Johnson and Shelby), then northward to include Henry County, then east-northeast to the Ohio State line.
EAST – The Indiana and Ohio State line.
SOUTH – The Ohio River, which is the Indiana and Kentucky border.
WEST – The Wabash River, which is the Indiana and Illinois border.




The above map shows the approximate boundaries of Hoosier Energy's member systems, which 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 and I-64. 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 27$^{O}$F to 75$^{O}$F, with record temperatures ranging from -27$^{O}$F to 105$^{O}$F.[1] The southernmost edge of the service area has monthly mean temperatures ranging from 31.0$^{O}$F to 79$^{O}$F, with extremes ranging from -23$^{O}$F to 108$^{O}$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 | 5,516 | 1,039 |
| Louisville, KY | 4,349 | 1,440 |
| Evansville, IN | 4,617 | 1,415 |
| Cincinnati, OH | 5,196 | 1,047 |

**Table 2: Normal Heating and Cooling Degree-Days[3]**

The normal annual precipitation for this area is approximately 41 inches per year.[4] Table 3 shows the National Oceanic and Atmospheric Administration (NOAA) Weather Divisions that encompass the Hoosier Energy service area, and the out-of-state weather divisions that border the Hoosier Energy service area.

[1] National Weather Service website http://www.crh.noaa.gov/ind/?n=localcli#h1
[2] National Weather Service website http://www.crh.noaa.gov/pah/climate/evvclimo.php
[3] National Weather Service websites http://www.ncdc.noaa.gov/oa/climate/online/ccd/nrmhdd.html and http://www.ncdc.noaa.gov/oa/climate/online/ccd/nrmcdd.html.
[4] National Weather Service website http://www.nws.noaa.gov/climate/local_data.php?wfo=ind.

| Indiana | Illinois | Kentucky | Ohio |
|---|---|---|---|
| West Central-4<br>Central-5<br>East Central-6<br>Southwest-7<br>South Central-8<br>Southeast-9 | East Southeast-7<br>Southeast-9 | Western-1<br>Central-2<br>Blue Grass-2 | West Central-4<br>Southwest-8 |

**Table 3: NOAA Weather Stations for the Hoosier Energy Service Territory**

### *1.1.3 Consumer Class Breakdown*[5]

The consumer mix on the Indiana portion of the Hoosier Energy system changed slightly over the 2001 - 2011 period. In 2001, 95.1% of the system's consumers were residential, while in 2011, 94.4% were residential. The number of residential consumers increased from 219,228 in 2001 to 277,750 in 2011. By the year 2032, the number of residential consumers is forecast to increase 20.2 percent to 333,793. The percentage of total residential consumers served is forecast to remain the same in the year 2032 (94.4%).

In 2001, 4.8% were Commercial and Other consumers compared to 5.5% in 2011. The total number of consumers in this sector grew from 11,096 to 16,263 during this period, representing a growth of 5.5%. The percentage of Commercial and Other sector in the year 2032 is forecast to be 5.5 percent, similar to the present mix. The number of consumers in this class is forecast to increase 20.5% to 19,593 in 2032.

The total number of consumers from the Industrial sector, which is defined as loads requiring transformation greater than 1,000 kVA, increased from 132 to 209 during the 2001 through 2011 period, for a net gain of 58 percent. The forecast number of 186 consumers in the year 2032 indicates an annual decrease of 0.5 percent.

The proportions of the aggregated member energy sales are different from the consumer mix. The residential class proportion of sales decreased from 64.2% in 2001 to 61.2% in 2011 due primarily to a large increase in sales to the Industrial Sector. The actual member system residential energy sales increased 34.1% from 3,052 GWh in 2001 to 4,093 GWh in 2011. The year 2032 residential sales forecast is 4,896 GWh – 58.7% of total sales.

Hoosier Energy experienced significant growth in sales to the Industrial classification between 2001 and 2011. Energy sales increased 60.3% from 1,209 GWh in 2001 to 1,650 GWh in 2011. The portion of total sales to this sector increased from 21.7% in 2001 to 24.7% in 2011. Total energy sales proportion is forecast to be 26.9% (2,240 GWh) for the year 2032.

The proportion of sales to the Commercial and Other sector remained constant at 14.1% from 2001 to 2011. Actual sales increased from 671 GWh in 2001 to 943 GWh in 2011, for an overall

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

increase of 40.5 percent. Total energy sales of this class are forecast to be 1,203 GWh in 2032, or 14.4 percent of total sales.

In aggregate, member-system energy sales increased 40.7 percent from 4,752 GWh in 2001 to 6,686 GWh in 2011. The member-system energy sales forecast of 8,339 GWh for 2032 represents an increase of 24.7% from the 2011 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 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 the IURC and Hoosier Energy consider conservation, load management, co-generation, 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

This IRP will enable Hoosier Energy to expect the lowest possible 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 Hoosier Energy 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 dramatically affect cost assumption tradeoffs between the type, quality and availability of fuel burned and the allowable emissions level at Hoosier Energy's existing and future generating stations. The Plan was structured to be flexible enough to incorporate not only existing regulations but also possible further restrictions.

In terms of future retail choice, recent events in the industry have slowed down the momentum to embrace a fully deregulated environment. Therefore, this plan contemplates no significant impact of a fully deregulated retail market to Hoosier Energy and its members. However, the plan does consider the relatively high risk environment created by a deregulated wholesale market and its impact on a utility's obligation to serve retail load.

### *1.3.2 Supply-Side Resource Considerations*

In addition to the forecast demand and energy requirements, which dictates the type of generation resource required, and a capital and operating cost analysis, which determines the most cost effective resource for the required need, Hoosier Energy considers additional factors during the evaluation of generation alternatives. For example, Hoosier Energy uses a mix of owned-resources and power purchases and sales to attempt to mitigate risks, such as operating, ownership and market risks.

In addition, Hoosier Energy must consider environmental regulations, permit requirements, construction timelines, and numerous site-specific issues. Besides these considerations, the overall level of generation reserves required to maintain the desired level of system integrity and reliability must be considered.

### *1.3.3 Demand-Side Resource Considerations*

In 2009, Hoosier Energy completed an extensive analysis of energy efficiency and demand-side management programs. This work, which was performed by GDS Associates and Summit Blue Consulting was titled Energy Efficiency & Demand Response Potential Report for the Hoosier Energy Member Territory. The Report provided detailed descriptions and analysis of all demand-side programs considered and recommended for Hoosier Energy and was included is Appendix A1 in this IRP. Hoosier Energy continues to use that report to manage existing and develop new programs. For this IRP, Hoosier Energy has provided its 2013 Demand Side Management Report, which is included as Appendix A2.

### *1.3.4 Conclusions*

As a result of Hoosier Energy's load forecasting 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 has brought 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 and there is currently no capability to effectively store it. Therefore, while power purchases may, at times, be a least-cost alternative, ownership of generation is a necessary component of this least cost plan.

Hoosier Energy will continue to offer member systems a menu demand-side measures to promote the more efficient use of supply-side resources. This includes the new wholesale tariff, which was implemented in April of 2010, and reviewed again in 2013, that provides incentives for both demand response program participation and load shifting. Hoosier Energy's recently completed demand response and energy efficiency market potential study remains an integral part of Hoosier Energy's integrated resource plan.

In compliance with the Hoosier Energy Board adopted policy to pursue the incorporation of renewable resources, Hoosier Energy has included several renewable resources within the integrated resource 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 and supply-side and demand-side resource mix, Hoosier Energy expects to have sufficient resources for the immediate future.

In anticipation of future needs and consistent with a desire to continue to diversify the resource mix with cost-effective resources, Hoosier Energy will continue efforts to add demand-side and renewable resources as follows:

1. Continued implementation and penetration of the demand response and energy efficiency programs identified as cost effective in the 2013 Demand Side Management Report, which is attached as Appendix A2 to this IRP.
2. Hoosier Energy will continue to pursue cost-effective, renewable resources in the future including wind, solar, landfill gas, hydro and coalbed methane generation facilities. These resources are smaller than typical supply-side resources, which provide diversity and risk mitigation advantages. As described in Section 3.1.5, Hoosier Energy has revised its Board Policy in 2014 to set a target of obtaining 10% of member energy requirements from renewable resources by 2025. By the end of 2021, Hoosier Energy expects to have 105 MW of renewable generation capacity in its portfolio.
3. Hoosier Energy will explore additional peaking capacity to fulfill short term needs as identified in Section 6 of this IRP. Options include market capacity purchases, asset purchases and unit sales from existing units. This need is dependent upon Hoosier Energy's ability, and the market acceptance, of continuing unit contingent power sales, which is appropriate for risk management and diversification purposes.

In addition, the wholesale power market remains an integral part of Hoosier Energy's resource plan. Purchases from and sales into the market will continue to be an appropriate and economical complement to Hoosier Energy existing resource mix.

## 1.5 Comparison to Prior Short-Term Action Plan

In its 2011 Integrated Resource Plan filing, Hoosier Energy submitted the following short-term action plan:

1. Continued implementation and penetration of the demand response and energy efficiency programs identified as cost effective in the 2011 Demand Side Management Report, which is attached as Appendix A2 to this IRP.
2. Hoosier Energy will continue to pursue cost-effective, renewable resources in the future including landfill gas, hydro and coalbed methane generation facilities. These resources are smaller than typical supply-side resources, which provide diversity and risk mitigation advantages. By the end of 2016, Hoosier Energy expects to have 110 MW of renewable generation capacity in its portfolio.
3. As a response to recent and proposed environmental regulations, Hoosier Energy is currently performing an analytical review of its potential long-term resource options. Following approval by its Board of Directors, Hoosier Energy expects to file this assessment with the IURC in April 2012.

During the period subsequent to the Plan filing, Hoosier Energy has continued to pursue the strategies described in its short-term action plan. Hoosier Energy has continued to implement its demand response and energy efficiency programs. The programs and their results are contained in the 2013 Demand Side Management Report, which is attached as Appendix A2 to this IRP.

Hoosier Energy has continued to add cost-effective renewable resources to its resource portfolio. In addition, Hoosier Energy has added 18 MW of renewable generation since 2011, with plans, which have been budgeted and approved by the Board, to add an additional 51 MW by the end of 2016.

Hoosier Energy performed an analytical review of its potential long-term resource options and filed the assessment with the IURC in April 2012. As a result of this study, the decision was made to idle Ratts Unit 1 in 2014 and Ratts Unit 2 in 2015.

# 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 five 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 B through F present the base, high, low, base-mild and base-extreme forecasts. Section 2.4 presents the data used to develop the forecast. Section 2.5 and Appendix G present the load shape and electricity consumption patterns for the Hoosier Energy system.

## 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. These needs are to:

- 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.

Before 1992, RUS allowed Hoosier Energy to develop a full PRS every three years, with annual updates in other years. A full PRS would entail the redevelopment of all models and information. The annual updates would include use of the models developed during the full PRS, with updated annual information. In 1992, RUS issued new rules that allowed Hoosier Energy to develop a full PRS every two years, with no annual updates.

According to RUS rules, Hoosier Energy completed a full PRS in December 1991. After the completion of the December 1991 PRS, RUS revised its filing requirements. As a result of the transition to the new filing requirements, no PRS updates were necessary, or compiled during 1992 and 1993. Since then, Hoosier Energy has developed a PRS in 1994, 1997, 1999, 2001, 2003, 2005, 2007, 2009, 2011 and 2013. At this time all the member distribution boards have approved their individual 2013 PRS documents and Hoosier Energy's 2013 PRS dated October 2013 was officially approved by the Hoosier Energy Board of Directors at the November 2013 meeting. For this IRP study the numbers as presented are based upon the 2013 PRS, which is the active PRS. The 2013 PRS is a 20-year forecast of expected member system load and, as such, covers the period from 2013 through 2032. For purposes of the IRP, Hoosier Energy assumed load growth of 1% in 2033 and 2034, which is an extension of the expected growth rate from 2030 through 2032.

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.

## 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.

$$HERES_t = \Sigma_i \; RESALES_{it} \qquad (2.1)$$

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).

$$\ln RAUSE_{it} = a_0 + a_1 \ln RAUSE_{i,t-1} + a_2 \ln RRPE_{it} + a_3 \ln RPCI_{it} + a_4 \ln HDD_{it} + a_5 \ln CDD_{it} + a_6 XR_{it} \quad (2.2)$$

$$\ln RRPE_{it} = b_0 + b_1 \ln RAUSE_{it} + b_2 \ln RADSK_{it} + b_3 \ln RAWPC_{it} + b_4 YR_{it} \quad (2.3)$$

$$\ln RC7_{it} = c_0 + c_1 \ln POP_{it} + c_2 ZR_{it} \quad (2.4)$$

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).

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

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. RUS recommended to Hoosier Energy that each cooperative contribute 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. In the past, RUS has recognized that 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 345[6].
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 values for the individual member system's Commercial, Industrial and Other classifications were reviewed by each member system for final approval.

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

### *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.

$$HENWP_t = \Sigma_i\ FWINPEAk_{it} \qquad (2.6)$$

$$HENSP_t = \Sigma_i\ FSUMPEAK_{it} \qquad (2.7)$$

$$HECWP_t = \Sigma_i\ FCWINPEAK_{it} \qquad (2.8)$$

$$HECSP_t = \Sigma_i\ FCSUMPEAK_{it} \qquad (2.9)$$

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; |
| HENSP | = | 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).

$$HETIME_t = ACT60HE_t \div ACT30HE_t \qquad (2.10)$$

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).

$$HE60NWP_t = HETIME_t * HENWP_t \qquad (2.11)$$

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

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

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

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).

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

Where:

| | | |
|---|---|---|
| t | = | A subscript representing annual data; |
| x | = | A subscript representing the various types of demands.<br>When:<br>x = 1 it represents the non-coincident winter season;<br>x = 2 it represents the non-coincident summer season;<br>x = 3 it represents the coincident winter season; and,<br>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.

***<u>Individual System Demands</u>***

To develop a peak demand forecast for each member system, relevant historical information was collected. 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).

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

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).

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

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).

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

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.

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

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.

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

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).

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

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

Where:

| | | |
|---|---|---|
| FCWINPEAK | = | Forecast member system coincident winter seasonal peak; |
| $CF_i$ | = | Member system coincident factor when:<br>i=w denotes winter<br>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), several alternative forecast scenarios are developed. The first is development of a forecast range, rather than a single value forecast. This allows review of the model's sensitivity to different economic input assumptions. For the most recent PRS, Hoosier Energy developed five alternative energy forecasts: *Base, Low, High, Base-Severe and Base-Mild Cases*. For the residential sector, the scenarios are differentiated based upon fluctuation of population, real per capita income and fuel prices. For the commercial and industrial sectors, the scenarios were differentiated based upon variation in the number of consumers and energy growth rates.

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 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-Severe* and *Base-Mild scenarios* represent the economic Base Case conditions under varying weather conditions. 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 five 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.

To date these various scenarios have only been developed and analyzed within the PRS econometrics model structure used by Hoosier Energy. The only case scenario that has been extended to an end-use load shape is the Base Case scenario. This scenario has been used in the development of the existing Hoosier Energy IRP analysis.

### *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 $R^2$ values and performing a root mean square percent error (RMSPE) analysis then statistically validates the residential energy model. The $R^2$ 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).

$$RMSPE = \{(1/n)\ \Sigma_i\ [(Y_i - Y_i')^2 / Y_i^2]\}^{(½)} \qquad (2.23)$$

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 as illustrated in Table 4 shows the performance of the econometric model.

| | Within Sample Period (1975-2011) | | |
|---|---|---|---|
| Region 1 | 2.40% | to | 4.38% |
| Region 2 | 2.41% | to | 3.34% |
| Region 3 | 2.70% | to | 3.55% |
| Region 4 | 1.93% | to | 2.38% |
| Region 5 | 1.84% | to | 2.90% |
| Overall Average | 2.85% | | |

**Table 4: 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 a changing population, such as the 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. 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 insure 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*

Hoosier Energy uses several methods to analyze the effects of weather upon forecast energy, forecast demand, historical energy and historical demand. The incorporation of the effects of weather into the future Hoosier Energy forecast is officially completed within the PRS. Hoosier Energy has also established a second methodology that allows examination of weather upon future forecasts on an hourly load shape basis. Currently this hourly load shape methodology is strictly used to support the Production Model needs and to allow for the testing of the weather sensitivity of demand. This load shape method is driven by the PRS energy results.

In the PRS, the effects of weather on future energy and demand are composed of two distinct processes. 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.

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.

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 under varying weather conditions.

The hourly load shape methodology allows for the testing of weather sensitivity of the hourly demand, and uses the Electric Power Research Institute (EPRI) software package HELM. This software allows Hoosier Energy to establish future total system hourly load shapes based upon:

- Forecast annual energy values;
- Defined hourly load shape models based upon seasons, day types and temperature bands;
- Defined calendars; and
- Defined "typical" weather year database.

The defined HELM "typical" weather (i.e., the "most likely to happen" weather condition) is developed using a different method than used in the PRS, since the database consists of average daily maximum and minimum temperatures. This weather database was developed monthly by selecting the actual month's weather that best represents "typical" weather over the study period. The database is representative of the Hoosier Energy service area and was not created for the individual member system service areas.

Listed below are the five steps that were used to develop the typical weather year. (January is shown as the example month.)

1. Total Degree-days (TDD) [i.e., the sum of the Heating and Cooling Degree-days] were calculated for each January in the study period. TDDs were used as a proxy for energy use.
2. The median January TDD value was determined from the sample data, and all of the January TDDs were reviewed and ranked based upon their deviation from the median value.[7]
3. The maximum, minimum, and the daily average of the maximum and minimum temperatures for each January in the study period were determined. As with TDD, temperature was used as a proxy for peak demand.
4. The mean January temperature value was determined from the sample data, and all of the January temperature values were reviewed and ranked based upon their deviation from the mean.[8]
5. The final decision on the "typical" January weather month was then made by the combination of best fitting median TDD and mean temperature values.

[7] The median value was used as a first test because it represented a midpoint of what had occurred over the sample period, and the median value does not suffer from skewing problems associated with a sample mean in the case of radical swings in temperatures.

[8] In evaluating the months for "typical" peak demand, the mean temperature value was used, and not the median, because you want to choose the temperature variable so that extreme values are reached. Mean values reflect extreme conditions.

Because each of the steps was performed for all twelve months (in order to create a typical weather year), this process required a great amount of time and detailed analysis[9]. After the "typical" weather year, seasonal calendar and total system load shape models were developed, an hourly load forecast was developed by using the driving input variable of annual energy[10].

This annual energy represents the "most likely" energy forecast obtained from the PRS under "normal" weather conditions. The resultant energy matches the PRS forecast energy, while the forecast peak hourly demand may vary from the PRS seasonal peak demand due to the alternative manner in which it is developed. With these benchmarks, "typical" weather, energy and demand values established, alternative weather scenarios can be developed and tested by varying the inputted weather conditions. Therefore, use of this process yields an informational database that supports the functioning of the Hoosier Energy production model, along with supplying a tool in which to study weather sensitivity on the Hoosier Energy system forecast hourly demands.

The methodology used to examine the effects of weather on historical energy and demand includes use of the HELM software package and is based on a similar process as discussed with the hourly load shape methodology. However, this process is much more complex, because the gap between the modeled and actual values of energy and demand must be bridged to allow for the actual weather effects on historical energy and demand to be examined. This process to examine the effects of weather does the following:

- Replicates what actually occurred in a modeled environment;
- Simulates the results that a model would produce under "typical" weather conditions by matching the defined typical weather database to the actual weather pattern;
- Calculates the hourly variation ratio between modeled actual and typical hourly demand values (weather adjustment factor); and
- Applies the hourly weather adjustment factor to the actual hourly load values that occurred.

The end result is an engineered hourly load pattern that shows the energy and demand values without the actual weather extremes. Hoosier Energy defines this process as "Weather Normalization" and it reveals the "true growth" experienced by the system over time. It also exposes the historical effects of weather on the system.

### *2.2.7 Potential Self-Generation Analysis*

In 1998, Hoosier Energy and the member systems surveyed the retail customers to determine the number and magnitude of self-generation facilities on the system. The survey found a total of 31 generators with a total rated capacity of 12,022 kVA. The majority of the units were diesel fired (24 units), with a rated capacity of less than 200 kVA (17). Only two units had a rated capacity of greater than 1,000 kVA and only eight had the capability to be synchronized with another power source.

[9] EPRI has updated the HELM software package to include an automated process that performs an analysis that defines a "typical" weather year.

[10] This weather normalization can now be performed within the HELM software, which should make the process easier and more accurate. In the future, Hoosier Energy will utilize this capability.

Given the lack of self-generation currently found on the Hoosier Energy system, the potential for customer development of self-generation during the planning period is considered low. Accordingly, Hoosier Energy does not anticipate self-generation to have any impact on generation, transmission, and distribution planning, or forecasting.

## 2.3 Forecasts

The forecasts generated by the PRS can be found in Appendices D through H.

Appendix B contains the Base Case 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 C and D, respectively, contain the Base-Severe and Base-Mild Case demand and energy forecasts for a 20-year period for the Hoosier Energy System. These two forecasts incorporate weather variations rather than load growth variations.

Appendix E 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 F 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 E, G and H 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
- 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 Form 7 and Bulletin 1-1. Monthly and annual data are reported on RUS Form 7 and annual figures are reported in 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. 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).

This data is reported in a format similar to that used on RUS Form 7.

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 Equations (2.2) and (2.3), 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.

### *2.4.2 Population and Real Per Capita Income*

Population and real per capita income were estimated for each member system's service area through the use of county-level data with the consumer class per county breakdown developed by the member system. Calculation procedures to estimate the two variables were similar with the initial requirement of the development of factors identified as the "county weights." This methodology used in the creation of the county weights, along with the defined service area values, is the same as used by the State Utility Forecasting Group (SUFG) and the Center for Econometric Model Research (CEMR) established within the Kelley School of Business at Indiana University.

The number of people living in a county is estimated and reported annually by a number of public and private agencies. Because each of the member systems serves only a portion of the respective counties, simply adding the total population of the served counties would not have been accurate in representing the member system consumers served. Instead, an estimate was made of the proportion of the county served by the cooperative. This process in determining the proportion of the county served by the distribution system involves the development of a "county weight" for each county served by the system. This "county weight" can be interpreted as the share of the county households served by the member system in that specific county. This interpretation is valid based upon the hypothesis that the average household served by the member system has the same average size as the average household found in the county. The development of these "county weights" involve the establishment of a ratio between the total number of households found in the counties within the service territory and the number of residential consumers (households) actually served by the member system in each of the counties.

The number of households located within each county is obtained through the various public and private agencies which publish this information. 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 these values over the historical time period in review. In order to determine the "county weights" to be used for the forecast period, it is theorized that the weighting, which is occurring in the most recent historical year, will be held constant and carry forward into the forecast time period.

Once all the county weights are developed for each of the counties served, the county level databases for both population and income, which are readily available from the various agencies, can then be transformed into what is known as "service area" population and income database. This is accomplished through the development of the product of the total county variables and the "county weights." 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.

With the population and income service area databases created, the real personal income variable can be developed. This variable is calculated by dividing the service area personal income by the CPI. The nominal dollar value for this variable is converted into constant 1982-1984 dollars. The average annual real per capita income is then calculated as the ratio of real personal income to population. For further explanation and the detailing of the various equations used in this process, refer to the actual Power Requirements Study document developed by Hoosier Energy.

### 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. The weighting is reflective of 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, U.S. Department of Energy and the American Gas Association. 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.

All data was reported in dollars per million Btu.

### 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. Data was collected on these variables from various sources produced by Purdue University and the U.S. Department of Agriculture.

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 review of 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 provides an 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.

Hoosier Energy, in conjunction with the National Rural Electric Cooperative Association-Rural Electric Research (NRECA-RER), the Electric Power Research Institute's Center for Electric End-Use Data (EPRI's CEED), and the private consulting firm ICF Resources, Inc., developed load shapes for twenty-six (26) residential end-uses, and hourly load patterns for commercial and industrial class consumers in 1995. These load shapes were developed from end-use metered data and studies obtained from other utilities, along with engineering models.

### *2.5.2 Total System Load Curves*

Appendix G 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. However, Hoosier Energy can construct its total system forecast load shape by customer class (i.e., residential, commercial, and industrial) and by certain end-uses. At this time, there is a very limited amount of interruptible load on the Hoosier Energy system.

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. Table 5 shows the forecast residential end-use load shapes available to Hoosier Energy.

| Class | End-Use |
|---|---|
| Residential | Water Heating<br>Cooking<br>Refrigerator Primary<br>Refrigerator Secondary<br>Freezer Primary<br>Freezer Secondary<br>Dishwasher<br>Clothes Washer<br>Clothes Dryer<br>Lighting-Regular<br>Lighting-Compact Fluorescent<br>Television<br>Microwave<br>Waterbed Heater<br>Residual<br>Central Air Conditioner<br>Room Air Conditioner<br>Heat Pump, Air to Air<br>Heat Pump, Air Primary<br>Heat Pump, Air Secondary<br>Heat Pump, Geothermal<br>Heat Pump, Dual Fuel<br>Electric Heat-Furnace Primary<br>Electric Heat-Furnace, Secondary<br>Electric Thermal Storage<br>Ventilation (for fossil fuels) |

**Table 5: Hoosier Energy End-Use Load Shapes**

The residential class and end-use load forecast load curves are not based on metering. Rather, they are gained through information based on EPRI's CEED and customized to represent the Hoosier Energy service territory.

For the Commercial and Industrial classes, Hoosier Energy decided to develop composite curves.

For the Industrial class load curve, an industrial load shape model was developed, through use of the HELM software package, from actual end-use metering data obtained from eleven Hoosier Energy member system industrial consumers. The predominant type of manufacturing operation was two-shift, automobile-related manufacturing. Of the eleven consumers from which this metered data was obtained, eight have manufacturing output directly related to the automobile industry. This relationship introduces strong patterns of usage that are inherent to automobile manufacture-type loads. Therefore, at this time the best available industrial model for the Hoosier Energy system primarily represents an automobile manufacturing, two-shift operation type consumer.

The energy forecast for the Industrial class consumer in this study comes from the Power Requirements Study (PRS). This forecast is developed and supported by the member system managers and PRS representatives, and the RUS reported Form 345 documentation. The forecast numbers represent the future load requirements for the entire industrial class at the end-consumer level. The industrial sector comprises less than 1% of all consumers served. The industrial sector contributes approximately 22% of the total annual Hoosier Energy sales to the end consumers.

The Commercial and Other load shape curve was obtained from CEED. This curve was modified to agree with the intuitively correct Hoosier Energy commercial load shape. Similar to the industrial sector, the commercial sector energy forecast driving the commercial load shape is developed within the PRS. This forecast is based upon historical growth patterns experienced by this class, and knowledge of the immediate personnel who work for the member systems.

### *2.5.4 Future End-Use Surveys*

Hoosier Energy conducted a residential end-use survey in 2013 – the fourteenth survey since 1979. The structure of the survey remained the same as that of the most recent survey, which was strictly an end-use, consumer characteristic survey that did not incorporate member system specific questions. Traditionally, Hoosier Energy has conducted its surveys over the telephone. However, as changing technologies have eroded the representativeness of surveying by telephone only, this survey, as well as that conducted in 2011, was conducted via telephone and e-mail, assuring a more representative and expanded sample.

The residential survey is used to support the RUS-required PRS, to develop the energy and demand forecasts, and to support Marketing programs. The survey also provides end-use/consumer characteristic knowledge to the distribution system and Hoosier Energy staffs.

Samples for the more recent surveys have been constructed to produce results that are accurate to within approximately ±5% at a 95% confidence level at the member system level, in accordance with RUS recommendations. At the Hoosier Energy level, the results are therefore accurate to within approximately ±1.25% at a 95% confidence level.

## 2.6 Load Forecast

Hoosier Energy's forecasted peak demand and energy for the period from 2015 through 2034 are displayed in Table 6 below. The forecasted compound average growth rate for both demand and energy is approximately 1.0% for the period. Table 7 displays Hoosier Energy's forecasted energy requirements by customer class, while Table 8 presents the forecasted annual peak demand and energy forecast for the base case, high load growth scenario and low load growth scenario.

| Year | Peak Demand (MW) | Annual Demand Growth (%) | Energy Requirements (MWh) | Annual Energy Growth (%) |
|---|---|---|---|---|
| 2015 | 1,446 | | 7,454,725 | |
| 2016 | 1,474 | 1.9% | 7,600,187 | 2.0% |
| 2017 | 1,502 | 1.9% | 7,756,121 | 2.1% |
| 2018 | 1,530 | 1.9% | 7,821,145 | 0.8% |
| 2019 | 1,557 | 1.8% | 8,086,585 | 3.4% |
| 2020 | 1,571 | 0.9% | 8,160,125 | 0.9% |
| 2021 | 1,584 | 0.8% | 8,233,293 | 0.9% |
| 2022 | 1,597 | 0.8% | 8,310,212 | 0.9% |
| 2023 | 1,606 | 0.6% | 8,364,215 | 0.6% |
| 2024 | 1,617 | 0.7% | 8,427,489 | 0.8% |
| 2025 | 1,629 | 0.7% | 8,498,231 | 0.8% |
| 2026 | 1,642 | 0.8% | 8,572,987 | 0.9% |
| 2027 | 1,657 | 0.9% | 8,656,481 | 1.0% |
| 2028 | 1,673 | 1.0% | 8,740,881 | 1.0% |
| 2029 | 1,683 | 0.6% | 8,792,237 | 0.6% |
| 2030 | 1,700 | 1.0% | 8,885,843 | 1.1% |
| 2031 | 1,719 | 1.1% | 8,985,433 | 1.1% |
| 2032 | 1,738 | 1.1% | 9,086,958 | 1.1% |
| 2033 | 1,755 | 1.0% | 9,177,828 | 1.0% |
| 2034 | 1,773 | 1.0% | 9,269,606 | 1.0% |
| CAGR % | | 1.0% | | 1.1% |

**Table 6: Forecasted Demand and Energy Requirements**

**Hoosier Energy Rural Electric Cooperative, Inc.**
**Breakdown of Forecasted Energy Requirements by Customer Class**
**For Calendar Years 2015 - 2034**

| Year | Residential | Commercial | Industrial | Other | Distribution System Lossses | Transmission System Losses | Total Member Sales |
|---|---|---|---|---|---|---|---|
| 2015 | 4,012,283 | 935,762 | 2,005,840 | 46,873 | 330,349 | 295,980 | 7,627,087 |
| 2016 | 4,053,719 | 942,801 | 2,097,128 | 46,873 | 336,843 | 301,885 | 7,779,249 |
| 2017 | 4,101,451 | 949,908 | 2,188,681 | 46,873 | 343,795 | 308,076 | 7,938,784 |
| 2018 | 4,143,638 | 957,578 | 2,199,001 | 46,873 | 346,844 | 310,629 | 8,004,563 |
| 2019 | 4,183,274 | 966,007 | 2,226,344 | 46,873 | 350,275 | 313,812 | 8,086,585 |
| 2020 | 4,225,357 | 974,512 | 2,243,360 | 46,873 | 353,357 | 316,666 | 8,160,125 |
| 2021 | 4,267,958 | 983,121 | 2,259,404 | 46,873 | 356,432 | 319,505 | 8,233,293 |
| 2022 | 4,313,354 | 991,829 | 2,275,995 | 46,873 | 359,671 | 322,490 | 8,310,212 |
| 2023 | 4,351,843 | 1,002,860 | 2,275,995 | 46,873 | 362,058 | 324,586 | 8,364,215 |
| 2024 | 4,397,369 | 1,015,342 | 2,275,995 | 46,873 | 364,869 | 327,041 | 8,427,489 |
| 2025 | 4,446,161 | 1,031,372 | 2,275,995 | 46,873 | 368,044 | 329,786 | 8,498,231 |
| 2026 | 4,500,201 | 1,045,814 | 2,275,995 | 46,873 | 371,417 | 332,687 | 8,572,987 |
| 2027 | 4,560,874 | 1,061,611 | 2,275,995 | 46,873 | 375,200 | 335,928 | 8,656,481 |
| 2028 | 4,619,479 | 1,080,333 | 2,275,995 | 46,873 | 378,998 | 339,203 | 8,740,881 |
| 2029 | 4,683,226 | 1,099,167 | 2,240,086 | 46,873 | 381,689 | 341,196 | 8,792,237 |
| 2030 | 4,750,067 | 1,118,034 | 2,240,086 | 46,873 | 385,955 | 344,828 | 8,885,843 |
| 2031 | 4,822,419 | 1,136,863 | 2,240,086 | 46,873 | 390,499 | 348,693 | 8,985,433 |
| 2032 | 4,896,486 | 1,155,730 | 2,240,086 | 46,873 | 395,150 | 352,633 | 9,086,958 |
| 2033 | 4,945,451 | 1,167,287 | 2,240,086 | 46,873 | 421,971 | 356,159 | 9,177,828 |
| 2034 | 4,994,905 | 1,178,960 | 2,240,086 | 46,873 | 449,060 | 359,721 | 9,269,606 |

**Table 7: Forecasted Demand and Energy Requirements by Customer Class**

**Hoosier Energy Rural Electric Cooperative, Inc.**
**Summary of Forecasted Demand and Energy Requirements - Base Case, High Load Scenario and Low Load Scenario**
**For Calendar Years 2015 - 2034**

| Year | Peak Demand - Base Case | Annual Energy Requirements - Base Case | Peak Demand - High Load | Annual Energy Requirements - High Load | Peak Demand - Low Load | Annual Energy Requirements - Low Load |
|---|---|---|---|---|---|---|
| 2015 | 1,446 | 7,454,725 | 1,540 | 7,869,521 | 1,412 | 7,186,154 |
| 2016 | 1,474 | 7,600,187 | 1,577 | 8,072,047 | 1,431 | 7,291,801 |
| 2017 | 1,502 | 7,756,121 | 1,610 | 8,283,840 | 1,443 | 7,403,581 |
| 2018 | 1,530 | 7,821,145 | 1,627 | 8,403,752 | 1,439 | 7,420,388 |
| 2019 | 1,557 | 8,086,585 | 1,648 | 8,541,284 | 1,441 | 7,452,758 |
| 2020 | 1,571 | 8,160,125 | 1,671 | 8,671,990 | 1,445 | 7,475,727 |
| 2021 | 1,584 | 8,233,293 | 1,696 | 8,803,755 | 1,448 | 7,497,635 |
| 2022 | 1,597 | 8,310,212 | 1,720 | 8,940,875 | 1,450 | 7,522,444 |
| 2023 | 1,606 | 8,364,215 | 1,741 | 9,056,214 | 1,449 | 7,523,962 |
| 2024 | 1,617 | 8,427,489 | 1,764 | 9,182,795 | 1,449 | 7,233,612 |
| 2025 | 1,629 | 8,498,231 | 1,789 | 9,318,630 | 1,451 | 7,549,821 |
| 2026 | 1,642 | 8,572,987 | 1,816 | 9,460,354 | 1,453 | 7,569,039 |
| 2027 | 1,657 | 8,656,481 | 1,845 | 9,612,613 | 1,457 | 7,596,105 |
| 2028 | 1,673 | 8,740,881 | 1,874 | 9,767,494 | 1,461 | 7,623,305 |
| 2029 | 1,683 | 8,792,237 | 1,898 | 9,891,777 | 1,459 | 7,616,033 |
| 2030 | 1,700 | 8,885,843 | 1,930 | 10,060,523 | 1,465 | 7,649,867 |
| 2031 | 1,719 | 8,985,433 | 1,965 | 10,237,827 | 1,471 | 7,688,220 |
| 2032 | 1,738 | 9,086,958 | 2,000 | 10,419,279 | 1,478 | 7,727,392 |
| 2033 | 1,755 | 9,177,828 | 2,036 | 10,606,826 | 1,484 | 7,766,029 |
| 2034 | 1,773 | 9,269,606 | 2,073 | 10,797,749 | 1,490 | 7,804,859 |

**Table 8: Forecasted Demand and Energy Requirements for Base Case, High Load Scenario and Low Load Scenario**

# 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, environmental factors and demand-side management. Future Resource Assessments are presented in Section 4 of this IRP.

The 2014 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 Resources

### *3.1.1 Generation Facilities*

Hoosier Energy operates generating stations with a total summer production capacity of approximately 1,750 MW. This capacity consists of 1,080 MW of coal-fired capacity and 670 MW of natural gas-fired capacity.

The Frank E. Ratts Generating Station is located near Petersburg, Indiana and began operation in 1970. The facility consists of two coal-fired steam generating units. Hoosier Energy will be idling the Ratts facilities in order to meet EPA mandates. Unit One is scheduled to be idled on December 31, 2014 and is not included as an active generation resource in this IRP. Unit Two is scheduled to be idled on April 15, 2015 and is included as an active generation resource only until its scheduled idling date.

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. Except for those 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 rating of 172 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.

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.

Hoosier Energy produces power from coalbed methane at its Osprey Point Renewable Energy Station, which began operations in May 2013. The facility is located in on the Merom station grounds in Sullivan County and consists of four reciprocating engines, which are fueled by the combustion of coal bed methane gas collected through an underground collection system linking several CBM wells on the Merom property. Coalbed methane technology has been widely used to collect gas for pipelines. This project was built under IURC certificate of need authority granted in Cause No. 43893.

Hoosier Energy's newest generating station is the Livingston Renewable Energy Plant, located near Pontiac, Illinois. 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.

Table 9 summarizes Hoosier Energy's owned generation facilities.

| Unit | Summer Capacity | Winter Capacity |
|---|---|---|
| Ratts 2 | 100 | 105 |
| Merom 1 | 492 | 500 |
| Merom 2 | 490 | 498 |
| Clark-Floyd | 3.4 | 3.4 |
| Holland | 314 | 336 |
| Worthington | 175 | 184 |
| Lawrence | 175 | 190 |
| Livingston | 15 | 15 |
| Osprey Point | 3 | 3 |
| Total Rated Capacity | 1,767 | 1,834 |

**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 least-cost service to member systems. Hoosier Energy purchases 200

MW from Duke Energy Indiana under two separate, cost-based, long-term purchase agreements. Both agreements are for 100 MW and 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. The first agreement runs through 2017 and the second runs through 2023. Hoosier Energy has also signed a third agreement with Duke Energy Indiana to purchase an additional 50 MW of capacity and energy for the period beginning in January 2016, and ending on December 31, 2025.

### *3.1.3 Unit Power Sales*

Hoosier Energy sells unit contingent power to Wabash Valley Power Association (WVPA). This unit contingent sale includes both Merom units (120 MW off each) and the Ratts units (30 MW off each) for a summer total of 300 MW of unit contingent power through 2014. As a result of the Ratts idling, the sale decreases to 276 MW (120 MW off each Merom unit and 36 MW from any source) in 2015. The WVPA sale runs through 2017.

### *3.1.4 Firm Power Sales*

Hoosier Energy serves a single municipal customer, Troy Municipal. The Troy Municipal agreement is a full-requirements contract.

### *3.1.5 Renewable 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 first 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 first project under the Renewable Energy Program was development of the Clark-Floyd Landfill methane gas project. This 2 MW project was commissioned in October 2007. Capacity was increased in June of 2009 to 3.4 MW. The sole source of fuel for the project is methane gas collected from the Clark-Floyd Landfill in southern Indiana. This project was built under IURC certificate of need authority granted in Cause No. 43140.

Hoosier Energy's second project under the Renewable Energy Program was the Story County wind project. Story County 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 purchased power agreement for energy, capacity, and renewable energy credits. Hoosier Energy is participating in conjunction with other cooperatives with coordination provided by ACES.

Hoosier Energy's third project under the Renewable Energy Program was the Dayton Hydro facility in Dayton, IL. This project is a 20-year power purchase agreement to procure 3.6 MW of generation from Dayton Hydro facility in Dayton, IL. Hoosier began receiving output from this facility in August 2011.

In Cause No. 43893, the IURC granted Hoosier Energy's certificate of need request to build and operate the Osprey Point Renewable Energy Station. Osprey Point is designed to be a baseload generation facility fueled by the combustion of coal bed methane gas collected through an underground collection system linking several CBM wells on the Merom property. The methane, which would otherwise be released into the atmosphere naturally over time, contains between 95% and 97% methane – comparable to natural gas. Phase 1 of the project commenced operations in May 2013 and currently produces approximately 3 MW. It is expected that Phase 1 will produce 13 MW when at full capacity. Tentatively, Phase 2 would increase capacity an additional 12-15 MW when it comes online later this decade.

Hoosier Energy is developing a third landfill gas generation facility in Davis Junction, Illinois. This facility, known as Orchard Hills, is projected to provide 16 MW of capacity and energy with an expected online date of January 2016. This project is being built under IURC certificate of need authority granted in Cause No. 43987.

In 2011, Hoosier Energy purchased the 15.6 MW Livingston Renewable Energy Plant landfill gas facility near Pontiac, IL. The plant consists of three turbine engines fueled by landfill methane gas, which is sourced from the 460-acre Livingston Landfill. Hoosier Energy began receiving generation output from this facility in October 2013.

Other renewable initiatives include:

- The development of seven small-scale solar facilities and three small-scale wind facilities across Hoosier Energy's southern Indiana service territory. The solar facilities are located in the following counties: Decatur, Johnson, Sullivan, Bartholomew, Rush, Morgan and Dubois. The wind facilities are located in Sullivan, Dubois and Bartholomew counties. Interested persons can track the output of each facility at the following website: http://www.hepn.com/renewablespilot.asp.
- Participation in EPA's Landfill Methane Outreach Program (LMOP).
- Participation in the National Renewable Cooperative Organization. This organization will focus on developing large-scale renewable projects on a national or regional level.
- Developed a renewable program called EnviroWatts. This program allows Hoosier Energy's member cooperatives to offer their retail customers the option of buying power from a renewable resource.

### *3.1.6 Demand-Side Resources*

As defined by 170 IAC 4-7-1 Hoosier Energy operates several DSM measures.[11]

<u>*Wholesale Tariffs*</u>

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

[11] 170 IAC 4-7-1 (j) defines DSM resource as a resource (i.e., a project used by a utility to provide electric energy service to the customer) that reduces the demand for electrical power by applying a DSM program to implement a DSM measure(s).

pricing. The tariffs were reviewed and confirmed by Hoosier Energy in 2013. Below is a description of the changes to the Standard Wholesale Tariff:

1. Production Demand Charge - To support residential control programs, significant changes were made for recovering production demand-related costs. The new Standard Wholesale Tariff better 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. The tariff bases production demand in off-peak periods on average use in peak periods. Charges are calculated based on metered demand in June, July and August with demand in September, October and November based on the average of these three peak months. To better ensure that the members are able to earn a return on their load control investment, the metered, coincident demands used for member billing will be based on the Hoosier monthly system maximum load during which load control was operated. A similar mechanism at a lower rate was developed for the peak winter months of December, January and February with demand in March, April and May based on averages from the three peak months.

   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 and opportunities to avoid costly market energy purchases. Load control protocols will also consider the impact on consumer satisfaction. Based on these load control criteria, the primary mechanism for the flow through of power supply benefits to the members is through the Production Demand Charge.

   The new Standard Wholesale Tariff better 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.

2. Energy Charge - The new Standard Wholesale Tariff includes both on-peak and off-peak energy charges, with the on-peak charges set much higher than the off-peak energy charges. On-peak periods for energy charges are narrowly defined as including ten 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.

3. Transmission Demand Charge - Costs related to 69 kV radial transmission lines were shifted from transmission to substation/radial line demand charges to achieve a more consistent treatment of radial line costs. Transmission charges remain unbundled in the new Standard Wholesale Tariff. Current transmission charges are based on non-

coincidental (NCP) demand at each point of delivery during the highest “rolling 30-minute interval” in the month. Charges in the new Standard Wholesale Tariff 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 revision in the Transmission Demand Charge can reduce the members’ cost to serve Electric Thermal Storage (ETS) heating loads under certain circumstances. Under the old tariff, it was possible for a member to incur additional cost under the Transmission Demand Charge if the ETS load on a delivery point causes a monthly peak demand on the substation during the over-night hours when the heating system is charging the bricks for heat storage. Under the new Standard Wholesale Tariff, the billing demand has been modified to a demand coincident with the Hoosier system monthly peak, which is very unlikely to occur during the hours that the ETS is charging.

*Optional Wholesale Tariffs*

Hoosier Energy offers four optional 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

Distributed Generation Purchase Tariff
- Consumers with qualifying distributed generation facilities
- 50 kW to 2,000 kW nameplate rating
- Interconnection and other requirements
- G&T will pay $0.053 per kWh

Voluntary Curtailment Rider to Industrial Power Tariff (IPT)
- Available to IPT 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)
- Intended for few customers who generate own power on continuing basis
- Service option and rates for back-up, supplemental, or standby service
- Requires minimum annual contract demand

*Interruptible Power Tariff*

The Interruptible Power Tariff provides a demand charge discount in exchange for either load curtailment by the retail customer or the purchasing of buy-thru power at market prices by the retail customer. Although the Interruptible Power Tariff has been available since 1994 and Hoosier Energy has consistently marketed the Tariff to customers, only one customer has elected to take service under this Tariff. As required by the tariff, this customer has designated 3 MW of load as interruptible. Because the customer has elected to purchase buy-thru power at market prices, the interruptible load is not included as a resource. Due to the offering of Interruptible Power Tariff No. 2, this Interruptible Power Tariff is no longer available for new customers.

*DSM Programs*

Hoosier Energy has developed a number of demand response and energy efficiency programs. These programs are detailed in the 2013 DSM Report attached as Appendix A2.

## 3.2 Significant Issues Affecting Resources

### *3.2.1 Environmental Factors*

*Environmental Rules and Regulations*

Coal generation continues to be a target for new rules and tightening regulations. A broad strategy to reduce dependency on coal and increase reliance on natural gas and renewables is warranted. The chart below reflects an outlook for current rules developed by IHS-CERA.

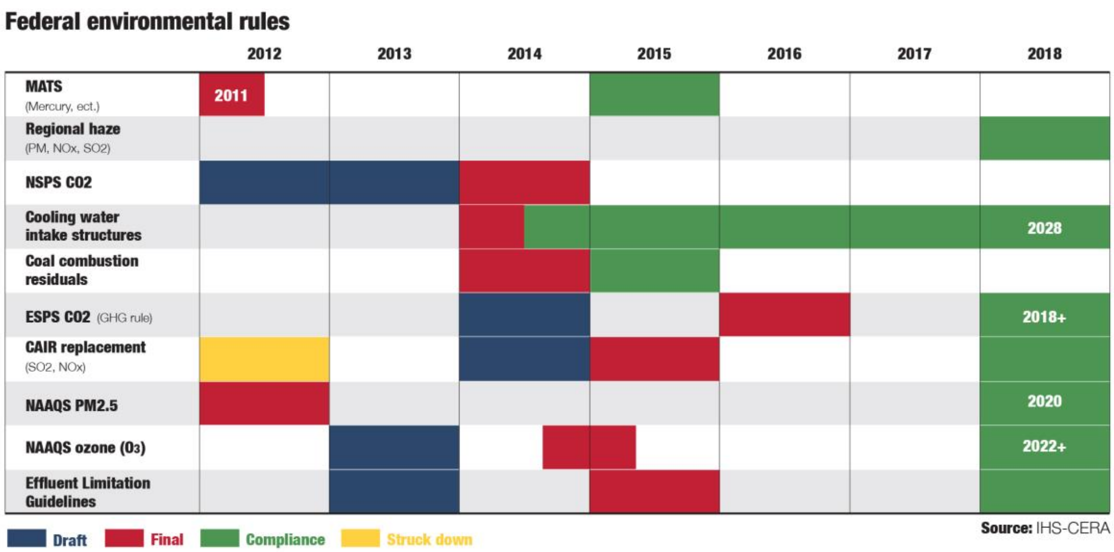



**Table 10: Federal Environmental Rules**

As shown in the timeline above, the Mercury and Air Toxins (MATS) rule is effective in 2015 or 2016 for coal generators that are granted a one year waiver by the state. The MATS rule will require closure of coal units and creates the potential for supply disruptions under extreme conditions, such as a repeat of this past winter's Polar Vortex.

*SO2 and NOX Emission Reduction Requirements under CSAPR*

On August 8, 2011, the Cross-State Air Pollution Rule (CSAPR) was finalized to replace the Environmental Protection Agency's Clean Air Interstate Rule (CAIR). Unlike CAIR, CSAPR designates an overall state cap for annual emissions for SO2 and NOx, as well as individual allocations on a unit by unit basis. This means that trading allowances outside of an individual state increases the risk of EPA determining that the state has exceeded its cap and those who have traded allowances will be held liable at a 2-1 penalty.

CSAPR was challenged by a number of states and the rule was vacated by the US Court of Appeals for the District of Columbia in August 2012. However, the Court allowed CAIR to remain in place until EPA developed a replacement rule. EPA requested the Supreme Court in June 2013 for a review of this decision. On April 29, 2014, the Supreme Court reversed the lower court's opinion vacating CSAPR. On June 25, 2014, the EPA petitioned the lower court to lift the stay on CSAPR. A decision is expected in 2015. CAIR remains in place and no immediate action from States or affected sources is expected while the court considers the motion.

*Consent Decree with Environmental Protection Agency*

On November 4, 2010, Hoosier Energy finalized a consent decree with the EPA and the state of Indiana that requires reduction in primary pollutants commencing in 2011. Under the terms of the Consent Decree, Hoosier Energy is required to limit the level of $SO_2$ and NOx emissions on system-wide basis, as well as on a unit basis. Hoosier Energy is also required to limit Particulate Matter emissions on a unit basis at both Merom and Ratts and limit $H_2SO_4$ emissions at Merom on a unit basis. To the extent that emissions reductions are more stringent in other Federal emissions rules, Hoosier Energy must comply with the more stringent of the individual requirements.

Hoosier Energy's fundamental strategy for environmental compliance is rooted in a least cost philosophy through a coordinated effort encompassing fuel selection, installation and operation of environmental control systems, and reliance on emission markets. Environmental control technologies are evaluated on an ongoing basis for potential benefits to reduce the overall cost of compliance.

*Mercury Emission Reduction Requirements*

On March 15, 2005, EPA issued the Clean Air Mercury Rule (CAMR) to permanently cap and reduce mercury emissions from coal-fired power plants for the first time. Indiana, through IDEM, adopted the EPA version of CAMR in October 2007. On February 8, 2008, the U.S. Court of Appeals for the District of Columbia ruled that EPA's 2005 Clean Air Mercury Rule violated the Clean Air Act by evading mandatory cuts in mercury pollution from coal-burning power plants. This decision invalidated the EPA's controversial cap-and-trade approach to regulating mercury emissions, effectively eliminating federal regulations requiring mercury emission monitoring and control.

The EPA announced its proposed CAMR replacement, the Utility Boiler Maximum Achievable Contol Technology (MACT) standards, in March 2011. The final rule, the Mercury and Air Toxics Standards (MATS), was finalized in 2012, with a three-year implementation period ending on April 16, 2015, and a one-year extension option for sources unable to meet the compliance deadline. This proposed rule was appealed by numerous entities, but was upheld by the U.S. Court of Appeals for the District of Columbia on April 15, 2014. The MATS rule establishes minimum emissions reductions amounts at power plants that will reduce their mercury emissions by 90% and acid gases by 88%. Compliance with the MATS rule will be costly and will likely force the retirement, or fuel conversion, of a large amount of coal-fired generating capacity in the Midwest, including Indiana. The impact of these retirements is likely to tighten reserve margins in the Midcontinent ISO for the next few years.

*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.

*National Ambient Air Quality Standards*

The EPA has set National Ambient Air Quality Standards (NAAQS) for six principal pollutants, which are known as “criteria” standards. These standards include Carbon Monoxide, Lead, NO2, Ozone, Particulate Matter and SO2. A number of these standards are under review, which could potentially lead to more stringent limits. The extent of the review, as well as the timing of implementation remains uncertain.

*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.

| 2013 Data | Ratts | Merom | Total |
|---|---|---|---|
| Fly Ash Generated (Tons) | 25,700 | 238,800 | 264,500 |
| Bottom Ash Generated (Tons) | 4,500 | 26,200 | 30,700 |
| FGD Sludge Generated (Tons) | 0 | 475,500 | 475,500 |
| Stabilizing Additive Used | 0 | 6,000 | 6,000 |
| Total CCBP (Tons) | 30,200 | 746,500 | 776,700 |

**Table 11: Hoosier Energy By-Products Summary**

Despite Hoosier Energy's interest in promoting utilization of its CCBP materials, onsite disposal is the destination for the vast majority of the combustion by-products generated by Hoosier Energy's facilities. The Merom Station disposes of its CCBP in an onsite landfill regulated by IDEM. The current active disposal area, as designed, is capable of providing volumetric capacity for 21 years of station operation.

The Ratts Station disposes of its CCBP in wet impoundments (ash ponds). Four ash ponds have been constructed to date. Two ponds are currently active. In 2011, an on-site landfill was developed on top of one of the inactive ash ponds. The ash ponds are dredged and removed as is allowed to be dewatered prior to placement in the new landfill. IDEM regulates the wastewater discharge from the ash ponds under the National Pollution Discharge Elimination System permit program and the landfill through its solid waste program.

For both plants, the most significant environmental effect associated with onsite disposal of CCBP is groundwater contamination. At Merom, as a condition of the solid waste disposal permit issued by IDEM, a groundwater-monitoring program has been in service for over 30 years and will continue until well after the disposal operation is discontinued. Thus far there has been no indication of off-site groundwater contamination. With the addition of the landfill at Ratts, the plant has begun to monitor groundwater also.

*Hazardous Waste*

Per the Resources Conservation and Recovery Act (RCRA), each of Hoosier Energy's generating stations is considered a "conditionally exempt small quantity generator of hazardous wastes." To qualify for this exemption, each of Hoosier Energy's generating stations produce less than 100 kilograms of hazardous waste per month. Hazardous wastes are accumulated onsite and transported off site for disposal as necessary. All applicable regulatory requirements are followed. Also, as allowed under RCRA, both stations burn used oil generated onsite for energy recovery.

*Clean Air Act 111 (d) Existing Plant Rulemaking*

EPA released the proposed greenhouse gas rules for existing plants in June 2014 and this new regulation represents the primary risk to consistent operation of coal-fired facilities. The rule established different target emission rates (pounds of CO2 per MWh) for each state due to regional variations in generation mix and electricity consumption, but overall a 30 percent reduction by 2030 is the target. EPA project the rule will cost between $7.3 and $8.8 billion by 2030, but lead to only a 3 percent increase in electricity rates.

While the rule requires the states to develop and submit implementation plans, the rule uses four "building blocks" to determine expected CO2 reductions. EPA targets for Indiana include:

1. Improve efficiency of all coal plants by 6 percent
2. Increase dispatch of existing natural gas combined-cycle facilities to 70 percent capacity factor displacing coal generation.
3. Increasing generation from renewable resources.
4. Increase energy efficiency to a 11.1 percent cumulative savings level by 2029.

EPA plans to issue a final rule by June 2015. The target date for states to submit their proposed plans to EPA is June 2016, but states can apply for a one-year extension. After a plan is submitted, EPA will have a year to either approve plans or send them back to states for revision. If a state does not submit an adequate plan, EPA is authorized to impose a federal plan to drive the necessary reductions. Along with NRECA, the state and many others, Hoosier Energy is now analyzing the 1,600 page rule.

MISO developed an analysis of the EPA proposal that was discussed with stakeholders on September 17, 2014. The current analysis provides some insights on the cost of implementing 111(d), but appears to be a high-level view and therefore lacks some significant cost items. Hoosier Energy will encourage MISO to quantify the additional costs of new transmission development, natural gas pipeline development (including the cost of firm transportation and supply), and heat rate improvements at existing power plants that the analysis appears to require. Inclusion of these and perhaps other requirements would make this a more complete analysis.
In addition, as a FERC-approved RTO, MISO is responsible for the provision of reliable electricity to its footprint. MISO is uniquely positioned to identify the reliability concerns that may result due to the accelerated retirement or reduced output of existing units, increased reliance upon natural gas CCs, additional renewables, and the short compliance timeline. MISO should identify the reliability issues, develop transmission solutions and estimate those costs. A combination of these two analyses would provide a more complete picture of the challenges faced by this region to comply with the EPA's 111(d) rule.

### 3.2.2 Economic Factors

*Fuel Prices and Fuel Practices*

Hoosier Energy fuel 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 $SO_2$ removal)
- Fuel oil (for unit start up)
- Chemical additives for FGD
- Ammonia for SCRs

An assessment of the present cost and availability shows that coal has the most significant impact on Hoosier Energy costs – equal to roughly 85% of fuel-related program costs. Table 122 shows Hoosier Energy's recent historical coal costs.

| Fuel Cost ($ per MWh) | 2011 | 2012 | 2013 |
|---|---|---|---|
| Ratts | 31.14 | 34.36 | 34.21 |
| Merom | 21.14 | 25.40 | 26.54 |

**Table 12: Recent Historical Fuel Costs**

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.

Fuel inventory practice is based on target, minimum inventories subject to prevailing market conditions. Hoosier Energy currently maintains a target minimum of a 45-day supply at the Merom generating facility. Hoosier Energy also is targeting a 20-day minimum supply at the Ratts generation facility for the Winter of 2014 – 2015, and will be depleting the coalpile after that in anticipation of the facility's idling.

Hoosier Energy has the option of receiving coal shipments either by rail or truck at the Merom generating facility, while the Ratts generation facility is currently 100% truck delivery.

*Natural Gas and Transportation*

Summer and Winter gas service to the Worthington, Lawrence County and Holland stations is secured on a short-term basis. In 2011, Hoosier made an economic decision to serve the Lawrence County and Worthington facilities with interruptible pipeline capacity, rather than firm capacity. Hoosier continues to utilize the natural gas providers' firm pipeline capacity to serve the Holland natural gas facility. Hoosier Energy assumes that adequate pipeline capacity is available to serve the requirements of all current and potential gas fired generating facilities.

*Avoided Cost Calculation*

Table 13 presents the avoided costs for 2013 through 2034 in nominal dollars per kW-month and dollars per MWh. These rates are developed consistent with the IURC's QF calculation. Hoosier Energy included the potential avoided transmission cost in the evaluation of DSM resources. The methodology is detailed in the Energy Efficiency and Demand Response Potential Report attached as Appendix A1.

| | Avoided Fixed Cost ($/kW-mo) | Avoided On-Peak Energy Cost ($/MWh) | Avoided Off-Peak Energy Cost ($/MWh) |
|---|---|---|---|
| 2013 | $ 3.57 | $ 32.03 | $ 26.53 |
| 2014 | $ 3.64 | $ 42.78 | $ 29.92 |
| 2015 | $ 3.69 | $ 36.84 | $ 25.69 |
| 2016 | $ 3.75 | $ 36.99 | $ 26.10 |
| 2017 | $ 3.80 | $ 38.58 | $ 27.42 |
| 2018 | $ 3.86 | $ 40.01 | $ 28.35 |
| 2019 | $ 3.92 | $ 41.50 | $ 29.34 |
| 2020 | $ 3.98 | $ 44.11 | $ 30.86 |
| 2021 | $ 4.05 | $ 46.97 | $ 32.55 |
| 2022 | $ 4.12 | $ 49.04 | $ 33.69 |
| 2023 | $ 4.19 | $ 50.27 | $ 34.80 |
| 2024 | $ 4.26 | $ 50.53 | $ 35.27 |
| 2025 | $ 4.33 | $ 52.70 | $ 36.53 |
| 2026 | $ 4.41 | $ 53.90 | $ 37.66 |
| 2027 | $ 4.49 | $ 55.17 | $ 38.78 |
| 2028 | $ 4.56 | $ 56.61 | $ 39.82 |
| 2029 | $ 4.65 | $ 58.09 | $ 41.47 |
| 2030 | $ 4.74 | $ 57.43 | $ 46.27 |
| 2031 | $ 4.83 | $ 60.06 | $ 48.35 |
| 2032 | $ 4.93 | $ 62.58 | $ 51.34 |
| 2033 | $ 5.03 | $ 65.73 | $ 54.36 |
| 2034 | $ 5.13 | $ 68.18 | $ 57.55 |

**Table 13: Avoided Costs**

### *3.2.3 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-one primary substations and approximately 350 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 2012, and 2013. The next reliability audit will likely occur in 2015. 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.

*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 of the TVMP. Activities associated with TVMP execution include mechanical vegetation clearing/trimming, chemical vegetation control programs, aerial patrols, danger tree identification, erosion control, and wildlife protection.

*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. Hoosier Energy's internal system load is expected to continue to receive grandfathered status from the MISO. Maintaining grandfathered transmission status continues to be a least cost and low risk means to serve load obligations internal to Hoosier Energy's transmission system. The MISO transmission expansion cost allocation methodology will require Hoosier Energy to bear some cost of regional transmission projects. Hoosier Energy personnel have stayed involved in this discussion and generally support regional participant funding so long as benefits can be clearly demonstrated and that the cost is weighted toward those that are receiving the greater benefit. The federal government is encouraging expansion of the bulk transmission system for the purpose of integrating renewable energy (upper Midwest wind energy) into the MISO and PJM power market regions without causing transmission congestion. This could be a significant initiative and is being followed closely.

Table 14 displays Hoosier Energy's historical and expected future transmission investment through 2018.

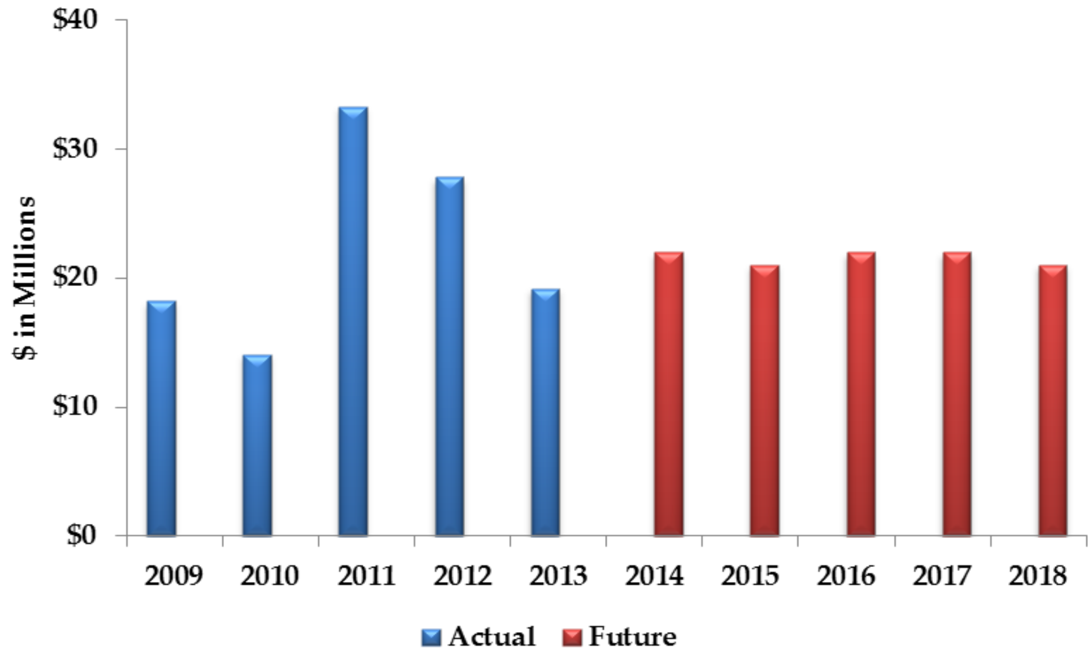



**Table 14: Hoosier Energy Transmission Investment**

*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).

# 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. The section is broken into two subsections. The first subsection describes the screening of the supply-side resources. The second subsection describes the DSM screening.

## 4.1 Resource Screening

Table 155 shows the supply-side resources that are generally considered. These possible capacity alternatives were evaluated based on cost, reliability and a maturity of technology bases. The cost information in this section was obtained from various industry and market resources, the State Utility Forecasting Group, the EPRI Technical Assessment Guide and Hoosier Energy consultants.

| Supply-Side Resources |
|---|
| Market Power Purchases |
| Long-Term Power Purchases |
| Combustion Turbines |
| Combined Cycle |
| Baseload (Coal) |
| Distributed Generation |
| Non-Utility Generation |
| Renewable Resources |
| New Technologies |
| Demand-Side Resources |

**Table 15: Supply-Side Resources Considered**

Initially to consider each of these technologies, a qualitative screening analysis was performed, where Hoosier Energy identified those supply-side options suited to the Hoosier Energy system, and eliminated those supply-side options that were inappropriate based on the following criteria:

- Does the capacity resource match Hoosier Energy's need?
- Is the supply-side addition appropriate for Hoosier Energy's service territory?
- Is the technology commercially available and reliable?
- Are the costs and reliability of the technology quantifiable?

Any supply-side option that passed the qualitative screening was then 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. <u>Installed Cost</u>: Computation of installed cost in $/kW for each supply-side option.
2. <u>Monthly Fixed Costs</u>: 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 supply-side resources are then compared against the aforementioned tests to arrive at the least cost supply-side resource plan.

#### *4.1.1 Market Power Purchases*

The wholesale power market has developed standard products that are commonly traded by market participants. Purchases/sales are usually in increments of 50 MW for specific hours of the day or week, such as on-peak hours (5x16), around-the-clock (7x24), weekend peak hours (2x16), and off-peak only (7x8). Forwards and options are generally traded for the following periods of the year:

- Winter (January and February)
- March and April
- May
- June
- Summer (July and August)
- September
- Fourth quarter (October, November, December)

The two most common products are 5x16 monthly forwards and options. Under a monthly forward contract, energy is on a take-or-pay basis every peak day of the month (usually 20 or 21 days) for the 16 peak hours of the day. This amounts to a capacity factor of approximately 45% making forwards an intermediate resource. Daily options are available for the same 16-hour peak period, but the buyer has a day-ahead option on whether to take the power or not. Therefore, options are more of a peaking resource but still lack the intra-day flexibility and require a longer daily take period (16 hours) than a combustion turbine.

With the Midcontinent ISO Market development, the industry continues to transition to financial products and these market power purchases are now primarily risk management tools.

Hoosier Energy actively purchases both forward and spot market power to serve member and contract load. Hoosier Energy also actively sells power in the wholesale market to maximize the value of resources. Hoosier Energy is a member of ACES, which acts as Hoosier Energy's agent for wholesale transactions. ACES has 21 cooperative members and therefore has a working knowledge of the power market. ACES uses this knowledge to develop proprietary market pricing information for a variety of forward products, including forwards and options. In addition, ACES monitors the internet-based market exchanges to track the power market. Hoosier Energy uses information from ACES and other sources to make resource decisions.

### *4.1.2 Long-Term Power Purchases*

Long-Term Power Purchases represent purchases that are at least one year in length and up to 20-25 years. Long-Term Purchases allow for a more diverse portfolio of generation assets, which tends to reduce overall risk (operating, unit contingent, etc.). Long-Term Purchases 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.

### *4.1.3 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 three years (for procurement, licensing and construction) makes CTs an attractive option from a flexibility standpoint.

Hoosier Energy monitors the capacity and variable costs of the most likely CT resources, including General Electric's LM6000, 7EA and 7FA machines. Hoosier Energy's research is based upon quotes from vendors and consultants as well as industry publications.

### *4.1.4 Combined-Cycle Generation*

Combined-cycle (CC) capacity is generally favorable for providing intermediate energy needs. While variable operating costs are generally lower than CTs due to greater efficiency, capital costs are higher. CCs require a larger footprint and much greater amounts of water for cooling, and CCs experience significant efficiency degradation if cycled. Therefore, in order to recoup higher fixed costs, CCs are likely to be economical with annual capacity factors above 30%.

One key feature of CCs is their ability to be "staged-in" meaning that CTs that are already on the system may be converted to CC through the addition of a steam recovery cycle. This not only improves the efficiency but also adds capacity. Generally, two CTs are combined with a steam recovery unit to make a CC unit.

Combined-cycle resources have traditionally been at a disadvantage in the Midcontinent region because the existing resource fleet is significantly weighted in coal-fired, baseload units. The incremental cost of the older and less-efficient coal facilities in the Midcontinent has tended to drive the forward market and supply the region's intermediate resource needs. This created a negative spark spread for CCs where the price for a 5x16 forward was less than the cost to generate that power from a gas-fired, combined cycle resource. However, due to environmental regulations and coal cost increases these older, less-efficient coal facilities are no longer inexpensive. In addition, demand has outpaced the addition of new baseload resources. These factors have forced natural gas-fired facilities to become increasingly on the margin in the 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.

### 4.1.5 Baseload Coal 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. The economics and availability of Illinois Basin coal makes baseload coal generation an attractive resource for an Indiana utility. However, given the likelihood of the implementation of some type of Greenhouse Gas Regulation in the near future, it will be economically infeasible to build a traditional baseload coal generating facility. For this reason, a coal-fired Integrated Gasification Combined Cycle unit with Carbon Capture Sequestration (IGCC w/CCS) was considered as a supply-side resource option.

An IGCC uses a gasifier to turn coal and other carbon based fuels into synthesis gas (syngas). It 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 baseload coal versus combined cycle is highly dependent upon a number of factors, including environmental costs, transmission conditions, siting issues and, most importantly, the price of natural gas. In general, coal-fired generation can be competitive with CC generation at capacity factors greater than 45% assuming no carbon legislation. The higher capital and operational costs associated with IGCC technology would increase the required capacity factor, particularly with the inclusion of CCS. The potential for carbon legislation, which will likely weigh heavier on the cost of coal-fired generation, dramatically changes the economic cross-over point.

### 4.1.6 Distributed Generation

Options for distributed generation alternatives to meet Hoosier Energy’s peaking power requirements would be Wind, Solar photovoltaic technology, diesel generators and small gas turbines. The installed cost of Solar PV ranges from $2,500 - $4,000 per kW, while the installed cost of wind ranges from $2,500 - $8,000 per kW, depending upon the size of the installation. The cost of distributed generating capacity for diesel or gas turbines is estimated to be above $1,000 per kW depending upon a number of factors, including the type of engine (diesel reciprocating engine or gas turbine), size, manufacturer, emission level, efficiency, etc. Hoosier Energy uses vendor quotes as well as participation in industry organizations, such as EPRI, as sources for this data.

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. Landfill and/or coalbed methane gas projects, which have an economic fuel source and may qualify for renewable benefits (such as renewable energy credits or RECs) can be economic versus central station power.

#### *4.1.7 Non-Utility Generation*

As discussed in Section 2.2.7, Hoosier Energy does not anticipate any significant amount of Non-Utility Generation to be added to the system. Hoosier Energy has investigated cogeneration projects with several large industrial customers in the past and none proved to be economic. At this time, this potential resource remains too uncertain to include in the IRP.

#### *4.1.8 Renewable Resources*

Renewable resources are technologies that draw energy from the sun, wind, oceans and rivers (hydro), plant matter and geothermal heat; in other words, use of the resources does not change their future availability. Other resources considered renewable are technologies fueled by landfill gas, coalbed methane and biomass. These technologies hold promise as generation alternatives in localized applications or for specific regions of the country as continued technological advances and experience reduce the risk related to their use and improve their efficiencies.

The Energy Policy Act of 2005 places significant emphasis on preserving scarce natural resources and protecting the environment. This cause is gaining national attention as new technological advancements and subsidies drive down the cost of some renewable resources. Hoosier Energy is committed to renewable energy as part of our corporate resource planning effort in support of environmental awareness and national energy issues facing the country.

As many as 30 states have adopted a requirement that utilities include a certain percentage of renewable resources within the total resource mix. This is known as a Renewable Portfolio Standard (RPS). Legislation requiring Indiana utilities to adopt a RPS has been proposed in the Indiana Legislature the last few years and debate continues.

Energy from wind resources has become a prominent component of most RPS discussions as cost reductions due to technology improvements and increases in traditional generation costs have combined to allow wind to be more competitive with fossil fuel resources. The problem with wind generation, especially in Indiana, is the intermittent nature of the resource. Although the cost of wind generation is becoming more competitive with coal-fired generation, the value of wind generation 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 the appropriate resource region to the load centers. This is a challenge that both utilities and the regional transmission organizations must solve.

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. Currently, Hoosier Energy is pursuing renewable resource opportunities not only within the Hoosier Energy service territory but also within the Midcontinent ISO footprint.

Incorporating additional economically viable renewable energy resources will be considered in conjunction with least cost and reliability priorities of the integrated resource plan. Likewise, alternative energy projects such as cogeneration and coal waste technologies may or may not qualify as renewable energy but could prove to economically provide supply-side diversification.

#### *4.1.9 New Technologies*

New technologies that may be viable in the future include fuel cells and energy storage. A fuel cell is a device that produces direct current electricity through an electrochemical process using a hydrogen rich gas such as natural gas or propane. No combustion of fuel takes place during the process, which makes the technology environmentally attractive. The only by-products are heat (via hot water or steam) and carbon dioxide which is not considered a regulated pollutant.

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."

It is anticipated that energy storage technologies will gain more importance in coming years as the electric industry evolves in response to environmental mandates, the movement toward a greater incorporation of renewable resources into utility portfolios and the improving economics of distributed generation. These developments will require a greater need for energy storage to allow for the balancing of energy supply and demand. Aside from traditional energy storage technologies, such as pumped storage and compressed air storage, there are a number of rechargeable battery storage technologies that are emerging and, while currently uneconomic for large scale use, they offer potential storage options in future years. Some of the more promising battery storage technologies are:

- Lead acid batteries. These are the oldest form of rechargeable battery technology and have been widely used for decades in the automotive, marine and aeronautical industries. There are two types of lead-acid storage technologies; lead-acid carbon and advanced lead-acid. As a mature technology, these batteries have been deployed in configurations of 10 to 20 MW. Advantages to lead acid batteries include their proven history, power-to-size ratio and life cycle, while disadvantages include their size and weight. Levelized costs of an advanced lead-acid battery system used in a transmission and distribution application are expected to approximate $1,200 per kW-year for a 20 MW installation.
- Lithium ion battery. These are the fastest growing platform for stationary storage applications, and are currently used in applications from laptop computers to plug-in

hybrid electric vehicles. Their application for larger-scale grid storage is still being developed. A lithium ion battery cell contains two reactive materials capable of undergoing an electron transfer chemical reaction. Levelized costs of a lithium ion battery system used in a transmission and distribution application are expected to approximate $1,000 - $1,200 per kW-year for a 20 MW installation.

- Sodium sulfur battery. These batteries are a commercial energy storage technology with demonstrated applications in distribution grid support and wind power integration. Sodium sulfur batteries operate in the range of 300 – 350 degrees C and have a discharge period of approximately 6 hours. Developed and primarily used in Japan, there are currently approximately 20 MW either installed or in process in the United States. Levelized costs of a sodium battery system are expected to range from $640 per kW-year for a 50 MW installation to $740 per kW-year for a 1 MW installation.
- Flow Batteries. Flow batteries refer to a group of batteries that are recharged through a process in which two chemical components are dissolved in a liquid solution within the system. These batteries can potentially provide greater storage than conventional batteries, but lower power flow. Flow batteries are currently an immature technology that are in their demonstration phase. Some types of flow batteries are:
    - Vanadium reduction and oxidation batteries.
    - Iron-chromium batteries.
    - Zinc-air batteries.

#### *4.1.10 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 was updated in 2013. Attached as Appendix A1 is the Energy Efficiency & Demand Response Potential Report for the Hoosier Energy Member Territory. This Report provides detailed descriptions and analysis of all demand-side programs considered and recommended for Hoosier Energy.

## 4.2 Future Resource Assessment

Section 6 includes an Assessment of Supply-Side Resources that provides additional detail on each potential resource considered for Hoosier Energy's future needs. Section 6 also includes the results of Ventyx Strategist Modeling performed by GDS Associates. The Strategist Modeling incorporates the impact of the demand-side management programs recommended by the Energy Efficiency & Demand Response Potential Report.

## 4.3 Future Resource Planning Criteria

### *4.3.1 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:

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

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.[12] The current required reserve margin is 7.30%.

While this may seem much lower than historical reserve margin requirements, unlike prior years 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 16 reflect values for the planning year beginning June 2014.

### *4.3.2 Environmental Analysis*

As Congress proceeds with the development and implementation of a comprehensive national energy policy, it is clear that a key component will be the establishment of a long-term strategy for addressing climate change with particular focus on electric power generation. In the face of growing energy demands and aging power infrastructure, electric utilities need a clear understanding of future emission reduction obligations in order to make the right investment decisions. This includes further reductions of $SO_2$ and $NO_x$ as well as future regulatory restrictions on carbon, mercury, 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.

[12] ReliabilityFirst standard BAL-502-RFC-02

#### *4.3.3 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, 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 the Midcontinent ISO's 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.

#### *4.3.4 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.

#### *4.3.5 Market Analysis*

Hoosier Energy is an active participant in many of the Midcontinent ISO committees and working groups. Hoosier Energy will continue to monitor the LMP market and the potential impact on resource planning.

### 4.4 Capacity Expansion Plan and Energy Requirements

Table 16 presents Hoosier Energy's Capacity Expansion Plan for the period from 2015 through 2024. This table compares the Summer Peak Demand requirements, as determined through Hoosier Energy's load forecasting, to Hoosier Energy's existing capacity resources. Table 16 also reflects the impact of the idling of the Ratts units upon Hoosier Energy's generation capacity and also shows that Hoosier Energy does not expect any impact on its generation capacity as a result of additional retirements, derating, plant life extensions, repowering or refurbishment. Table 17 compares Hoosier Energy's total energy requirements to its generation and other system resources. Tables 16 and 17 demonstrate that, absent the acquisition of additional resources, Hoosier Energy will have a need for additional capacity requirements during the Summer months of the forecasted period.

## Capacity Expansion Plan - Summer Peak

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Peak Demand** | | | | | | | | | | |
| Demand Forecast (1) | 1,490 | 1,521 | 1,539 | 1,549 | 1,560 | 1,574 | 1,587 | 1,600 | 1,609 | 1,620 |
| Reserve Requirement (2) | 109 | 111 | 112 | 113 | 114 | 115 | 116 | 117 | 117 | 118 |
| Peak Requirement | 1,599 | 1,632 | 1,651 | 1,662 | 1,674 | 1,689 | 1,703 | 1,717 | 1,726 | 1,738 |
| | | | | | | | | | | |
| **Resources (MW)** | | | | | | | | | | |
| Merom | 977 | 977 | 975 | 975 | 975 | 975 | 975 | 975 | 975 | 975 |
| Ratts | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Power Purchase | 200 | 250 | 250 | 150 | 150 | 150 | 150 | 150 | 150 | 50 |
| Holland | 312 | 312 | 312 | 312 | 312 | 312 | 312 | 312 | 312 | 312 |
| Worthington | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 |
| Lawrence | 176 | 176 | 176 | 176 | 176 | 176 | 176 | 176 | 176 | 176 |
| Renewables (3) | 33 | 54 | 70 | 85 | 92 | 97 | 105 | 114 | 119 | 124 |
| Unit Contingent Sales (4) | (276) | (276) | (276) | (200) | (200) | (200) | (200) | (200) | (200) | (200) |
| Adj. for Forced Outage Rate (5) | (113) | (115) | (124) | (133) | (141) | (144) | (151) | (158) | (162) | (170) |
| Total Resources Adjusted | 1,484 | 1,553 | 1,558 | 1,540 | 1,538 | 1,540 | 1,542 | 1,544 | 1,545 | 1,442 |
| | | | | | | | | | | |
| **Total Resources minus Peak Req.** | | | | | | | | | | |
| Excess / (Deficit) | (115) | (79) | (94) | (122) | (136) | (149) | (161) | (173) | (182) | (296) |

1 2013 Power Requirements Study Base Case Summer Peak Demand

2 Assumed long-term Midwest ISO reserve requirement of 7.30%

3 Estimated Renewable Resources

4 Assumes 200 MW Unit Contingent Sale beginning in 2018

5 Based upon current MISO capacity rules and plant performance both of which are subject to future changes.

**Table 16: Summer Peak Demand Requirements and Planned Resources**

*Source: PRS and Integrated Resource Plan*

| Year | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|
| Energy Requirements (GWh) | | | | |
| Members | 7,331 | 7,477 | 7,631 | 7,694 |
| Non-member Contract Sales | 1,841 | 1,971 | 1,864 | 1,493 |
| Surplus Sales | 1,001 | 1,126 | 914 | 877 |
| Total Energy Required | 10,173 | 10,574 | 10,409 | 10,064 |
| | | | | |
| Energy Resources (GWh) | | | | |
| Merom | 6,877 | 7,177 | 6,784 | 6,847 |
| Ratts | 111 | 0 | 0 | 0 |
| Power Purchase | 1,373 | 1,484 | 1,593 | 911 |
| Holland | 553 | 616 | 583 | 613 |
| Worthington | 49 | 59 | 55 | 60 |
| Lawrence County | 76 | 90 | 85 | 94 |
| Renewables - Generation | 266 | 356 | 355 | 355 |
| Renewables - PPA | 89 | 90 | 90 | 89 |
| Spot Purchases | 779 | 702 | 864 | 1,095 |
| Total Resources | 10,173 | 10,574 | 10,409 | 10,064 |

**Table 17: Energy Requirements and Planned Resources**

*Source: PRS and Integrated Resource Plan*

# Section 5: Resource Integration

# 5 Resource Integration

Pursuant to 170 IAC 4-7 Section 8, this section presents Hoosier Energy's preferred integrated resource plan (IRP). This section is divided into five subsections. The first subsection describes the Hoosier Energy IRP (or the preferred resource plan). The second subsection describes the development of the preferred resource plan. The third subsection describes certain risks and uncertainties associated with the preferred resource plan. The fourth subsection shows the financial impacts of the preferred resource plan. The final subsection discusses the flexibility of the preferred resource plan.

## 5.1 Preferred Plan Based on Hoosier Energy Resource Planning Criteria

As discussed in Section 1.3, Hoosier Energy's Integrated Resource Plan was developed based on 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.

Hoosier Energy's capacity expansion plan, as shown in Table 16, demonstrates sufficient capacity resources for the planning horizon.

Since 2004, Hoosier Energy has made a number of changes to its resource portfolio including:

- Construction of the 175 MW Lawrence peaking power plant, which began commercial operations in May of 2005.
- Negotiation of two long-term power purchases of 100 MW each from Duke Energy Indiana, with an additional 50 MW long-term purchase beginning in 2016.
- Renegotiation of a long-term sale with WVPA converting a firm power sale to a unit contingent sale.
- Development and then subsequent expansion of the Clark-Floyd Landfill methane gas facility.
- Purchase of 25 MW of wind generation from the Story County facility in central Iowa.
- Acquisition of 50% ownership interest in the Holland combined-cycle generation facility.
- Implementation of new wholesale tariff options.
- Completion of an extensive analysis of energy efficiency and demand-side management programs.
- 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
- Development of the Osprey Point Renewable Energy Facility in Sullivan County, IN

- Purchase of 25 MW of wind generation from the Rail Splitter Wind Farm in central Illinois through a PPA.

The above resource changes have not only reduced Hoosier Energy's future capacity and energy needs but also diversified Hoosier Energy's resource mix. The addition of the Holland Facility has continued this process as it allowed Hoosier Energy to add an intermediate, gas-fired resource. The Holland Facility has reduced reliance on market purchases and provides diversity for intermediate and peaking needs. The Holland Facility may also serve as a baseload resource if legislation and/or regulations limiting carbon emissions are implemented.

The DSM potential study (Energy Efficiency and Demand Response Potential Report) and the 2013 Demand Side Management Report have identified several cost-effective, demand-side programs to pursue. When implemented, these DSM programs will allow for continued diversification of resources through demand-side additions, such as residential water heater and air conditioner load control.

### *5.1.1 Least Cost*

Hoosier Energy will balance its portfolio of owned resources with a combination of short- and long-term market power purchases/sales. This includes unit contingent sales and long-term power purchase agreements to reduce short-term market reliance. This may also include forwards, options, tolling arrangements, and/or spot market purchases/sales. Market contracts offer the flexibility of varying the term of contracts, thus giving flexibility to respond to changes in market conditions and load forecasts.

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

### *5.1.2 Reliability*

This IRP addresses reliability in three ways:

1. Owned Utility Resources – Ownership of approximately 1,125 MW of baseload, 325 MW of intermediate, 350 MW of peaking generation and a growing portfolio of renewables allows Hoosier Energy to meet native load requirements. As a load-serving entity, Hoosier Energy has an obligation to serve member cooperatives. A portfolio of owned resources assures Hoosier Energy can reliably and economically provide wholesale power to member-owned cooperatives.
2. Planning Reserves – The IRP accounts for planning reserves as established by the Midcontinent ISO 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).
3. Transmission Reliability – Hoosier Energy continues to invest in the transmission system to accommodate growth and ensure reliable service. Membership in the Midcontinent ISO allows access to generation facilities, such as the Holland facility, which is interconnected to another Midcontinent ISO member. Through participation in the Midcontinent ISO,

Hoosier Energy benefits from the Midcontinent ISO's reliability tools such as the state estimator, real-time contingency analysis and regional outage coordination.

### *5.1.3 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. Hoosier Energy's preferred plan lessens risk associated with the market using a strategy of owned resources, long-term purchases and sales and short-term purchased power market contracts as illustrated below:

1. Unit Power Sales - Hoosier Energy has historically balanced a portion of its operating risk through Unit Contingent power sales to various counterparties. These sales provide Hoosier Energy with the ability to balance its generating resources and forecasted member sales and also provides revenue which can lower member rates. As discussed later, Hoosier Energy will continue to explore Unit Contingent sales in the future.
2. Wholesale Market Purchases and Sales -- The wholesale market provides short-term opportunities for both purchases and sales of power. Optionality exists to the extent Hoosier Energy staggers various purchased power contracts with differing expiration terms and conditions.
3. Joint Ventures -- Development of the Lawrence County facility in 2005 and acquisition of the Holland Facility in 2009 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 a resource plan is inherently uncertain and major cost categories require risk management. The following is a list of these major cost 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

Hoosier Energy recognizes that it faces a changing environment. The primary goal for this IRP was to develop a plan that would 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 though various scenario analyses.

#### *5.1.4 Flexibility*

Where practical and reasonably available, Hoosier Energy maintains some optionality to preserve planning flexibility in order to serve its members at a reasonable cost. The ability to pursue alternative strategies depending upon the market environment is an important component of the preferred plan. As stated above, Hoosier Energy's plan of using a mix of owned resources, long-term purchases and sales and short-term purchased power market contracts not only reduces risk, but also provides the flexibility necessary to respond to changing market conditions. The scenarios described below provide a couple of examples as to the flexibility provided by Hoosier Energy's preferred plan.

- High Market Prices-Capacity Shortages: Under this scenario, a seller's market for peaking power develops resulting in prices above that of Hoosier Energy's own cost to generate. Hoosier Energy has limited this exposure through ownership of generation resources and through the sale of unit-contingent power with varying expiration terms as part of the power supply portfolio.
- Low Market Prices-Capacity Surplus: A buyer's market develops resulting in prices below Hoosier Energy's owned generation costs. Again, Hoosier Energy has limited this risk by securing contracts with varying contract terms, while having a sufficient amount of owned resources fixed cost exposure.

#### *5.1.5 Greatest Influences on the Preferred Resource Plan*

Hoosier Energy has identified several variables and conditions that will influence the preferred resource plan, including unit power sales, load and price forecasts, the standard of reliability, the availability of peaking power and the timing of new resources. Hoosier Energy's compliance with CSAPR or its replacement regulations, MATS, the Consent Decree, future environmental regulations, and the retirement of the Ratts power station are also important. Each of these is briefly discussed below.

- The forecast of growth is the primary driver of resource acquisitions. Hoosier Energy's PRS includes five different forecasts (base, high-economic, low-economic, 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 7.30% as its minimum standard of reliability.
- Summer and winter peaking power is assumed to continue to be available in the region.
- Hoosier Energy's plan to comply with CSAPR or its replacement regulation, MATS and the Consent Decree is conservative to account for a variety of uncertain variables, including coal quality and availability and the emission reduction effectiveness of pollution control equipment. The plan also considers the potential for future environmental regulations, including restrictions on other pollutants such as carbon,

hydrogen chloride and sulfuric acid (H2SO4). No financial benefits are assumed because of the sale of emissions credits to other utilities.

- Both Ratts units are assumed to be idled, with Ratts Unit 1 being idled at the end of 2014 and Ratts Unit 2 being idled in April, 2015. Both Ratts units are expected to be and then retired in 2019.

#### *5.1.6 The Present Value of Revenue Requirement of the Preferred Plan*

For a cooperative such as Hoosier Energy, the impact on the total cost of service (the average price per megawatt-hour to members) is one of the primary considerations when determining the proper mix of resources. Based upon the strategy proposed within the Preferred Plan, Hoosier Energy's wholesale rates to members will increase approximately 3 percent annually in the long-term.

#### *5.1.7 Consideration of Non-Traditional Supply*

As detailed in Sections 3 and 4 of this Plan, Hoosier Energy is pursuing non-conventional technology, such as technology relying on renewable resources. In the past ten years, Hoosier Energy has added wind power, increased the capacity of the Clark-Floyd landfill generation project, acquired additional landfill gas generation, constructed a coalbed methane gas-fired facility and entered into a PPA with a hydro facility.

In addition, Hoosier Energy is pursuing additional landfill generation projects, as well as wind and solar generation projects. Hoosier Energy is also making progress toward the expansion of its coalbed methane gas generating facility.

With respect to energy efficiency and demand response, the Energy Efficiency and Demand Response Potential Study details the demand-side programs that Hoosier Energy plans to pursue.

### 5.2 Development of the Preferred Plan

Hoosier Energy's goals in developing its IRP were to enable the Company to achieve the lowest power supply cost for its 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 incorporates 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 scheduled power transactions is found in Section 3.1 Existing Resource Assessment. This section also provides additional detail on environmental, transmission and commodity forecasts. Sections 3.2 Future DSM Resource Assessment and 3.3 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 sources of supply-side resources were considered in the Hoosier Energy plan.

## 5.3 Financial Impacts

### *5.3.1 Effects of the Preferred Plan on Costs and Rates*

The Preferred Plan is forecast to increase Hoosier Energy's wholesale rates to members in the long-term by an average annual rate of approximately 3 percent.

### *5.3.2 Hoosier Energy's Ability to Finance New Resources*

Hoosier Energy's current investment grade status allows for ready access to public and private capital markets at market-based rates. Hoosier Energy anticipates maintaining this credit quality. Therefore, Hoosier Energy feels that adequate capital resources are available to finance the acquisition of a required resource.

## 5.4 The Preferred Plan's Flexibility

As stated, the primary goal of the IRP is to develop a plan that is low risk, reliable and cost effective. A secondary goal of the IRP is to develop a plan that is flexible to enable cost effective responsiveness to changing business circumstances. 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 Hoosier Energy's IRP. These regulations affect cost assumption tradeoffs between the type, quality and availability of fuel burned and the allowable emissions level of Hoosier Energy's existing and potential 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.

# Section 6: Integrated Resource Plan

# 6 Assessment of Resource Options

## 6.1 Introduction

In order to plan a portfolio of resources that will serve its members at the lowest possible cost, while ensuring adequate reliability and minimizing risk, Hoosier Energy has prepared an assessment of resource options. This assessment identifies the list of resources, and all associated cost and operational parameters, that will be included in Hoosier Energy's integrated system modeling process. Hoosier Energy contracted with GDS Associates to perform the assessment. Hoosier Energy's resource assessment and resource integration analysis was produced using the Strategist Integrated Planning System. This model, which is licensed to GDS Associates by Ventyx, has the capability to simulate production operations and develop least cost expansion plans. The production operations simulation establishes the optimal dispatch of generating resources and calculates the associated costs. The development of least-cost expansion plans includes comparisons of all combinations of potential resource additions to determine the portfolio of expansion units necessary to achieve planning reserve margin criteria at the lowest cost. Hoosier Energy's existing and currently planned generating resources were modeled using the Strategist Generation and Fuel ("GAF") module. Potential future units were modeled using the GAF and the Proview ("PRV") modules. (The PRV module of Strategist facilitates, among other things, the calculation of capital costs associated with future units.) The existing and future units were dispatched against the 2015-2034 Load Forecast. The 2015-2034 Load Forecast was modeled using the Strategist Load Forecast Adjustment ("LFA") module. Cost and performance data contained in this portion of the IRP report 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) emission costs, and (5) presence of $CO_2$ emission costs.

## 6.2 Hoosier Energy's Existing Supply-Side Resources

The following supply-side resources were incorporated into Hoosier Energy's assessment of resource options:

**Merom –** [redacted]

**Ratts –** [redacted]

[redacted]

[redacted]

**Holland –** [redacted]

**Worthington –** [redacted]

**Lawrence –** [redacted]

**Purchased Power Agreement –** [redacted]

**Clark-Floyd –** [redacted]

**Story County –** [redacted]

**Livingston -** [redacted]

[redacted]

**Orchard Hills –** [redacted]

**Osprey Point –** [redacted]

**Dayton Hydro –** [redacted]

[REDACTED]

**Table 18: Dayton Hydro PPA Contract Price**

[redacted]

**Sycamore Ridge –** [redacted]

**Rail Splitter –** [redacted]

**Cabin Creek –** [redacted]

**MISO Capacity Purchase** – [redacted]

**Solar PPA** – [redacted]

**Wind PPA** – [redacted]

**Renewable Resources** – [redacted]

[REDACTED]

**Table 19: Forecasted Annual Renewable Resource Energy Additions (MWh)**

### 6.3 Supply-Side Resource Alternatives

Supply-side resources typically include utility-owned generating capacity and/or purchases of power from other entities. Supply-side resources are distinguished from demand-side resources which are used to reduce energy consumption, or shift it to off-peak times, using energy efficient equipment and/or practices. Traditional supply-side resources include those that have historically been used to serve electric needs, as well as advanced or modified versions of these resources that

**Table 20: Forecasted Annual Renewable Resource Energy Additions (MWh)**

have been developed or are expected to be developed during the term of the study period. Examples of traditional supply-side resources include:

| | |
|---|---|
| Combustion Turbines | Resources typically used to serve peak load needs. These resources are characterized by relatively high operating costs and relatively low capital costs. |
| Combined Cycle Units | These resources are used to serve intermediate and baseload needs. All-in cost levels (costs including both operating and capital) have historically characterized these resources as the economic choice for dispatch over a mid-range of capacity factors. |
| Coal Units | Relatively high capital costs are balanced by relatively low operating costs for these baseload resources. Operating at high |

capacity factors facilitates spreading capital costs over large generation amounts making these units attractive for serving baseload requirements.

For the development of Hoosier Energy's IRP, a list of traditional supply-side resources was compiled. This list of resources defines the options that the model is able to choose in order to meet planning reserve criteria. The list of potential additions includes traditional supply-side options and renewable supply-side options. The list includes options that are typically included in potential resource assessments and represent generic generating assets. Selection of a particular type of resource from this list would indicate the type of capacity, rather than a specific asset, that would best serve new resource needs.

Potential capacity additions that were analyzed for this IRP are generic in nature in the sense that as Hoosier Energy approaches a time of capacity need, costs and availability of technically- and economically feasible alternatives will be assessed in great detail to ensure the optimum technology is chosen to fill actual needs. New capacity selections shown in each of the planning cases are indicative and could be supplied through participation in jointly-owned units, bilateral capacity purchases, or self-build options which could include either traditional or distributed generation options.

The complete list of options, along with operating characteristics and costs are shown in the table below. Further discussion of each option immediately follows the table. Capital costs and operating parameters (both characteristics and costs) were developed by Hoosier Energy. New resource capital cost obligations were modeled using an estimated cost of capital of 6%.

| Potential Resource | Type | Capital Cost | Capacity | Variable O&M | Heat Rate | Forced Outage Rate | SO2 Emissions | NOx Emissions | CO2 Emissions |
|---|---|---|---|---|---|---|---|---|---|
| | | (2012 $/kW) | (MW) | (2012 $/MWh) | (MMBtu/MWh) | (%) | (lbs/MMBtu) | (lbs/MMBtu) | (lbs/MMBtu) |
| IGCC with CCS | Gas | 6,599 | 100.0 | 8.45 | 10.70 | 8.00% | 0.01 | 0.015 | 20.6 |
| Conventional CC | Gas | 917 | 300.0 | 3.60 | 7.05 | 10.00% | 0.01 | 0.001 | 117 |
| Conventional CT | Gas | 973 | 100.0 | 10.37 | 10.85 | 10.00% | 0.03 | 0.001 | 117 |
| Peaking Unit Purchase | Gas | 300 | 200.0 | 4.00 | 12.00 | 20.00% | 0.01 | 0.06 | 119 |
| Wind PPA | PPA | | 50.0 | 50.00 | | 5.00% | | | |
| Solar PPA | PPA | | 10.0 | 75.00 | | 0.00% | | | |
| Contract Extension 2018 | | | 100.0 | | | | | | |
| Contract Extension 2024 | | | 100.0 | | | | | | |
| Contract Extension 2026 | | | 50.0 | | | | | | |

**Table 21: Summary of Supply-Side Resource Options**

**Integrated Gasification Combined Cycle with Carbon Capture and Storage (100 MW)** – The IGCC unit is sized at 100 MW, which is assumed to be Hoosier's portion of the plant. Hoosier would look for opportunities to participate as a minority partner on this type of facility. This unit is assumed to have a capital cost of $6,599/kW and variable O&M rate of $8.45, both in 2012 dollars. Variable O&M is escalated annually at inflation rates obtained from the Energy Information Administration's Annual Energy Outlook 2014. The unit's heat rate is 10.70 MMBtu/MWh with a forced outage rate of 8%. Its SO2 emissions rate is 0.01 lbs/MMBtu, NOx emissions rate is 0.015 lbs/MMBtu, and CO2 emissions rate is 20.6 lbs/MMBtu. The IGCC's planned maintenance schedule can be found in the table below. This option is available beginning in 2016.

| | Planned Maintenance (Number of Days) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
| IGCC with CCS | 29 | 8 | 57 | 8 | 21 | 8 | 21 | 8 | 8 | 49 |
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| IGCC with CCS | 8 | 21 | 8 | 21 | 8 | 8 | 49 | 8 | 21 | 8 |

**Table 22: Planned Maintenance Schedule – IGCC w/ CCS**

**Conventional Combined Cycle (300 MW) -** The CC unit is sized at 300 MW and has a capital cost of $917/kW and variable O&M rate of $3.60, both in 2012 dollars. Variable O&M is escalated annually at inflation rates obtained from the Energy Information Administration's Annual Energy Outlook 2014. The unit's heat rate is 7.05 MMBtu/MWh with a forced outage rate of 10%. Its SO2 emissions rate is 0.01 lbs/MMBtu, NOx emissions rate is 0.001 lbs/MMBtu, and CO2 emissions rate is 117 lbs/MMBtu. The CC's planned maintenance schedule can be found in the table below. This option is available beginning in 2018.

| | Planned Maintenance (Number of Days) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
| Conv. CC - Spring | 10 | 23 | 10 | 10 | 14 | 14 | 7 | 21 | 7 | 14 |
| Conv. CC - Fall | 23 | 10 | 10 | 10 | 3 | 3 | 7 | 0 | 7 | 3 |
| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Conv. CC - Spring | 14 | 7 | 21 | 7 | 14 | 14 | 7 | 21 | 7 | 14 |
| Conv. CC - Fall | 3 | 7 | 0 | 7 | 3 | 3 | 7 | 0 | 7 | 3 |

**Table 23: Planned Maintenance Schedule – Conventional Combined Cycle**

**Conventional Combustion Turbine (100 MW) -** The CT unit is sized at 100 MW and has a capital cost of $973/kW and variable O&M rate of $10.37, both in 2012 dollars. Variable O&M is escalated annually at inflation rates obtained from the Energy Information Administration's Annual Energy Outlook 2014. The unit's heat rate is 10.85 MMBtu/MWh and has a forced outage rate of 10%. Its SO2 emissions rate is 0.03 lbs/MMBtu, NOx emissions rate is 0.001 lbs/MMBtu, and CO2 emissions rate is 117 lbs/MMBtu. The CC's planned maintenance schedule is 4 days each Spring. This option is available beginning in 2018.

**Peaking Unit Purchase (200 MW) -** The Peaking Unit Purchase is intended to replicate units that may be available within the MISO market. These units would be approximately 15-years old and offer low capacity factors under current market conditions. This unit is sized at 200 MW and has a capital cost of $300/kW and variable O&M rate of $4.00, both in 2012 dollars. Variable O&M is escalated annually at inflation rates obtained from the Energy Information Administration's Annual Energy Outlook 2014. The unit's heat rate is 12.00 MMBtu/MWh and it has a forced outage rate of 20%. Its SO2 emissions rate is 0.01 lbs/MMBtu, NOx emissions rate is 0.06 lbs/MMBtu, and CO2 emissions rate is 119 lbs/MMBtu. The unit's planned maintenance schedule is 4 days each Spring. This option is available beginning in 2016.

**Wind PPA (50 MW) -** The Wind PPA is sized at 50 MW and has a variable O&M rate of $50.00 in 2012 dollars. Variable O&M is escalated annually at inflation rates obtained from the Energy Information Administration's Annual Energy Outlook 2014. The PPA has a forced outage rate of 5%. This option is available beginning in 2016.

**Solar PPA (10 MW) -** The Solar PPA is sized at 10 MW and has a variable O&M rate of $75.00 in 2012 dollars. Variable O&M is escalated annually at inflation rates obtained from the Energy Information Administration's Annual Energy Outlook 2014. This option is available beginning in 2016.

**Contract Extension 2018 (100 MW)** – This alternative is assumed to be an extension of the 100 MW PPA with Duke Energy Indiana that is scheduled to expire at the end of 2017. This contract is assumed to have an energy rate of $35.00/MWh in 2018, and then escalating at an annual rate of 2.5% in 2019 and beyond. For purposes of this IRP, this option is only assumed to be available from 2018 to 2023.

**Contract Extension 2024 (100 MW)** – This alternative is assumed to be an extension of the 100 MW PPA with Duke Energy Indiana that is scheduled to expire at the end of 2023. This contract is assumed to have an energy rate of $40.64/MWh in 2024, and then escalating at an annual rate of 2.5% in 2025 and beyond. For purposes of this IRP, this option is only assumed to be available from 2024 to 2025.

**Contract Extension 2026 (50 MW)** – This alternative is assumed to be an extension of the 50 MW PPA with Duke Energy Indiana that is scheduled to expire at the end of 2025. This contract is assumed to have an energy rate of $42.69/MWh in 2026, and then escalating at an annual rate of 2.5% in 2027 and beyond. For purposes of this IRP, this option is only assumed to be available from 2026 to 2027.

Hoosier Energy's participation in the MISO market also defines another supply-side alternative. In the integrated modeling portion of the IRP development, market capacity and market energy will be included as potential resources. For this IRP, Hoosier Energy limited the amount of potential annual market purchases or sales to 20 percent of that year's native load. It should be noted that Hoosier Energy does not approach the 20 percent threshold in any of the modeled portfolio results. Market prices will be discussed later in this report.

### *6.3.1 Risks Associated with Supply-Side Resources*

Each supply-side alternative is vulnerable to a number of risk factors. Cost risk factors include resource capital cost, resource fuel cost, resource emissions cost, resource financing cost, and market cost. Other risks include technology (*i.e.* reliability), load and energy growth, and types of products available in the MISO market (*e.g.* uncertainty surrounding the development and availability of market capacity). Risks will be addressed through sensitivity cases in the IRP modeling process. Additionally, the incorporation of different resource alternatives with varying emission rates into the modeling process will consider emission cost risk in all IRP modeling scenarios. Resource selection reaction to load and energy growth will be analyzed through a load and energy forecast sensitivity.

### *6.3.2 Fuel Price Assumptions*

Hoosier Energy purchased the Ventyx Power Reference Case Electricity and Fuel Price Outlook (Midwest, Fall 2013) in order to obtain projections of fuel, market, and emission cost rates. Hoosier Energy provided estimates of coal prices for existing and potential new coal units for years 2015-2018. The coal prices were then escalated at the same growth rate as Ventyx's delivered coal price forecast for the MISO-Indiana region, adjusted for inflation. Ventyx's natural gas forward curve assumptions were used for both Henry Hub and Chicago with Hoosier Energy delivery costs added. The following table shows fuel price projections that will be used in the modeling process. Coal prices are assumed to remain constant during all months of each year. Gas prices vary; prices shown below are simple averages of projected monthly prices.

[REDACTED]

**Table 24: Forecasted Fuel Prices**

### *6.3.3 Costs of Emissions*

There is much uncertainty currently with respect to costs associated with emissions from generating resources. The following tables show the assumed cost rates of emissions for the period from 2015 through 2034. The cost rates were obtained from the Ventyx Electricity and Fuel Price Outlook.

[REDACTED]

**Table 25: Forecasted Emissions Costs**

### *6.3.4 Market and Associated Prices*

Ventyx's hourly market prices representing a typical week for each month in years 2015-2034 were used. The table below represents a simple average of the typical week hourly prices for each year for the base case and each sensitivity.

[REDACTED]

**Table 26: Forecasted Market Power Prices**

## 6.4 Demand-Side Resources

Appropriate demand-side resource options have been selected and developed as part of the GDS energy efficiency and demand response study, which has been included as Appendix A1 of this IRP. The demand-side resource options have been incorporated into the load forecast employed by Hoosier Energy in this IRP.

## 6.5 Strategist Results

Strategist simulations were produced for a base case and five sensitivity cases. The base case was produced using base expectations of load and energy growth, and base expectations of fuel price growth. Sensitivity cases were developed as listed below.

1. High Gas Price – Base Case assumptions except that gas price growth was based on the high gas price forecast contained in the Ventyx Electricity and Fuel Price Outlook. As reflected in Section 6.3.4, power prices are also increased in this scenario.
2. Low Gas Price – Base Case assumptions except that gas price growth was based on the low gas price forecast contained in the Ventyx Electricity and Fuel Price Outlook. As reflected in Section 6.3.4, power prices are also decreased in this scenario.

3. High Load Growth – Base Case assumptions except that Hoosier Energy's high load and energy forecasts were modeled. Hoosier Energy's high load growth assumptions are included in Appendix E.
4. Low Load Growth – Base Case assumptions except that Hoosier Energy's low load and energy forecasts were modeled. Hoosier Energy's low load growth assumptions are included in Appendix F.
5. Federal Environmental Legislation – This case was based on the Ventyx Federal Environmental Legislation Scenario which was fashioned off a combination of bills introduced in the $112^{th}$ Congress related to greenhouse legislation. In the model, gas prices, market prices, and CO2 emission costs were changed.

The following tables show optimal expansion plans selected by Strategist for the Base Case and each of the sensitivity cases.

**Base Case Optimal Plan**

The Base Case optimal plan includes the 200 MW Peaking Unit Purchase in 2017, followed by 300 MW of Combined Cycle capacity in 2022, 100 MW of Combustion Turbine capacity in 2031, and the purchase of 50 MW of Wind Power in 2034. This plan has an NPV of $4.26 billion over the period. It should be noted that the NPV's of the five least expensive base case plans are within 0.4 percent of each other.

| | Base Case Plan Rank 1 | | Base Case Plan Rank 2 | | Base Case Plan Rank 3 | |
|---|---|---|---|---|---|---|
| Year | Addition | MW | Addition | MW | Addition | MW |
| 2015 | | | | | | |
| 2016 | | | | | | |
| 2017 | Peaking Unit Purchase | 200 | Peaking Unit Purchase | 200 | Peaking Unit Purchase | 200 |
| 2018 | | | | | | |
| 2019 | | | | | | |
| 2020 | | | | | | |
| 2021 | | | | | | |
| 2022 | Conventional Combined Cycle | 300 | Conventional Combined Cycle | 300 | Conventional Combined Cycle | 300 |
| 2023 | | | | | | |
| 2024 | | | | | | |
| 2025 | | | | | | |
| 2026 | | | | | | |
| 2027 | | | | | PPA Contract Extension | 50 |
| 2028 | | | | | | |
| 2029 | | | | | | |
| 2030 | | | | | | |
| 2031 | Conventional Combustion Turbine | 100 | Conventional Combustion Turbine | 100 | | |
| 2032 | | | | | | |
| 2033 | | | | | Conventional Combustion Turbine | 100 |
| 2034 | Wind Power Purchase | 50 | Conventional Combustion Turbine | 100 | | |
| Scenario NPV ($000) | $ 4,259,863.50 | | | $ 4,263,757.50 | | $ 4,267,064.50 |
| Percentage Above Low Cost Plan | | | | 0.09% | | 0.17% |

| | Base Case Plan Rank 4 | | Base Case Plan Rank 5 | |
|---|---|---|---|---|
| Year | Addition | MW | Addition | MW |
| 2015 | | | | |
| 2016 | | | | |
| 2017 | Peaking Unit Purchase | 200 | Peaking Unit Purchase | 200 |
| 2018 | | | | |
| 2019 | | | | |
| 2020 | | | | |
| 2021 | | | | |
| 2022 | Conventional Combined Cycle | 300 | Conventional Combined Cycle | 300 |
| 2023 | | | | |
| 2024 | | | | |
| 2025 | | | | |
| 2026 | | | | |
| 2027 | | | PPA Contract Extension | 50 |
| 2028 | | | | |
| 2029 | | | | |
| 2030 | | | | |
| 2031 | Conventional Combustion Turbine | 100 | | |
| 2032 | | | | |
| 2033 | | | Conventional Combined Cycle | 300 |
| 2034 | Conventional Combined Cycle | 300 | | |
| Scenario NPV ($000) | $ 4,267,598.00 | | | $ 4,276,852.50 |
| Percentage Above Low Cost Plan | | 0.18% | | 0.40% |

**Table 27: Base Case Scenarios – Five Lowest Cost Plans**

## High Load Scenario Optimal Plan

The High Load scenario optimal plan includes the 200 MW Peaking Unit Purchase in 2017, followed by 100 MW of Combustion Turbine capacity in 2018, 2021, 2030 and 2033, 300 MW of Combined Cycle capacity in 2024, the extension of the 50 MW PPA contract in 2027 and the purchase of 50 MW of Wind Power in 2032. This plan has an NPV of $4.96 billion over the period. It should be noted that the NPV's of the five least expensive High Load scenario plans are within 0.1 percent of each other.

| | High Load Plan Rank 1 | | High Load Plan Rank 2 | | High Load Plan Rank 3 | |
|---|---|---|---|---|---|---|
| Year | Addition | MW | Addition | MW | Addition | MW |
| 2015 | | | | | | |
| 2016 | Peaking Unit Purchase | 200 | Peaking Unit Purchase | 200 | Peaking Unit Purchase | 200 |
| 2017 | | | | | | |
| 2018 | Conventional Combustion Turbine | 100 | Conventional Combustion Turbine | 100 | Conventional Combustion Turbine | 100 |
| 2019 | | | | | | |
| 2020 | | | | | | |
| 2021 | Conventional Combustion Turbine | 100 | Conventional Combustion Turbine | 100 | Conventional Combustion Turbine | 100 |
| 2022 | | | | | | |
| 2023 | | | | | | |
| 2024 | Conventional Combined Cycle | 300 | Conventional Combined Cycle | 300 | Conventional Combined Cycle | 300 |
| 2025 | | | | | | |
| 2026 | | | | | | |
| 2027 | PPA Contract Extension | 50 | PPA Contract Extension | 50 | | |
| 2028 | | | | | | |
| 2029 | | | | | Conventional Combined Cycle | 300 |
| 2030 | Conventional Combustion Turbine | 100 | Conventional Combustion Turbine | 100 | | |
| 2031 | | | | | | |
| 2032 | Wind Power Purchase | 50 | Wind Power Purchase | 50 | | |
| 2033 | Conventional Combustion Turbine | 100 | Conventional Combined Cycle | 300 | | |
| 2034 | | | | | | |
| Scenario NPV ($000) | | $ 4,975,516.50 | | $ 4,978,689.00 | | $ 4,980,221.50 |
| Percentage Above Low Cost Plan | | | | 0.06% | | 0.06% |

| | High Load Plan Rank 4 | | High Load Plan Rank 5 | |
|---|---|---|---|---|
| Year | Addition | MW | Addition | MW |
| 2015 | | | | |
| 2016 | Peaking Unit Purchase | 200 | Peaking Unit Purchase | 200 |
| 2017 | | | | |
| 2018 | Conventional Combustion Turbine | 100 | Conventional Combustion Turbine | 100 |
| 2019 | | | | |
| 2020 | | | | |
| 2021 | Conventional Combustion Turbine | 100 | Conventional Combustion Turbine | 100 |
| 2022 | | | | |
| 2023 | | | | |
| 2024 | Conventional Combined Cycle | 300 | Conventional Combined Cycle | 300 |
| 2025 | | | | |
| 2026 | | | | |
| 2027 | | | | |
| 2028 | | | | |
| 2029 | Conventional Combustion Turbine | 100 | Conventional Combustion Turbine | 100 |
| 2030 | | | | |
| 2031 | Wind Power Purchase | 50 | Wind Power Purchase | 50 |
| 2032 | Conventional Combined Cycle | 300 | Conventional Combustion Turbine | 100 |
| 2033 | | | Wind Power Purchase | 50 |
| 2034 | | | Conventional Combustion Turbine | 100 |
| Scenario NPV ($000) | | $ 4,981,004.50 | | $ 4,981,432.00 |
| Percentage Above Low Cost Plan | | 0.11% | | 0.12% |

**Table 28: High Load Scenario – Five Lowest Cost Plans**

## Low Load Scenario Optimal Plan

The Low Load scenario optimal plan includes the 200 MW Peaking Unit Purchase in 2018, followed by the extension of the 50 MW PPA contract in 2026, the purchase of 50 MW of Wind Power in 2032 and 100 MW of Combustion Turbine capacity in 2033. This plan has an NPV of $3.71 billion over the period, which is the lowest cost plan. The NPV's of the five least expensive Low Load scenario plans are within 0.4 percent of each other.

| | Low Load Plan Rank 1 | | Low Load Plan Rank 2 | | Low Load Plan Rank 3 | |
|---|---|---|---|---|---|---|
| Year | Addition | MW | Addition | MW | Addition | MW |
| 2015 | | | | | | |
| 2016 | | | | | | |
| 2017 | | | | | | |
| 2018 | Peaking Unit Purchase | 200 | Peaking Unit Purchase | 200 | Peaking Unit Purchase | 200 |
| 2019 | | | | | | |
| 2020 | | | | | | |
| 2021 | | | | | | |
| 2022 | | | | | | |
| 2023 | | | | | | |
| 2024 | | | | | | |
| 2025 | | | | | | |
| 2026 | PPA Contract Extension | 50 | PPA Contract Extension | 50 | PPA Contract Extension | 50 |
| 2027 | | | | | | |
| 2028 | | | | | | |
| 2029 | | | | | | |
| 2030 | | | | | | |
| 2031 | | | | | | |
| 2032 | Wind Power Purchase | 50 | Conventional Combustion Turbine | 100 | Wind Power Purchase | 50 |
| 2033 | Conventional Combustion Turbine | 100 | | | Conventional Combined Cycle | 300 |
| 2034 | | | | | | |
| Scenario NPV ($000) | | $ 3,711,636.50 | | $ 3,715,077.50 | | $ 3,718,151.20 |
| Percentage Above Low Cost Plan | | | | 0.09% | | 0.18% |

| | Low Load Plan Rank 4 | | Low Load Plan Rank 5 | |
|---|---|---|---|---|
| Year | Addition | MW | Addition | MW |
| 2015 | | | | |
| 2016 | | | | |
| 2017 | | | | |
| 2018 | Peaking Unit Purchase | 200 | Peaking Unit Purchase | 200 |
| 2019 | | | | |
| 2020 | | | | |
| 2021 | | | | |
| 2022 | | | | |
| 2023 | | | | |
| 2024 | | | | |
| 2025 | | | | |
| 2026 | PPA Contract Extension | 50 | Conventional Combustion Turbine | 100 |
| 2027 | | | | |
| 2028 | | | | |
| 2029 | | | | |
| 2030 | | | | |
| 2031 | | | | |
| 2032 | Conventional Combined Cycle | 300 | | |
| 2033 | | | | |
| 2034 | | | | |
| Scenario NPV ($000) | | $ 3,724,568.00 | | $ 3,725,747.00 |
| Percentage Above Low Cost Plan | | 0.35% | | 0.38% |

**Table 29: Low Load Scenario – Five Lowest Cost Plans**

## High Gas Price Scenario Optimal Plan

The High Gas Price scenario optimal plan includes the 200 MW Peaking Unit Purchase in 2017, followed by the extension of the 100 MW PPA contract in 2022, the addition of 300 MW of Combined Cycle capacity in 2024 and the extension of the 50 MW PPA contract in 2027. This plan has an NPV of $4.52 billion over the period. The NPV's of the five least expensive High Gas Price plans are within 0.2 percent of each other.

| | High Gas Prices Plan Rank 1 | | High Gas Prices Plan Rank 2 | | High Gas Prices Plan Rank 3 | |
|---|---|---|---|---|---|---|
| Year | Addition | MW | Addition | MW | Addition | MW |
| 2015 | | | | | | |
| 2016 | | | | | | |
| 2017 | Peaking Unit Purchase | 200 | Peaking Unit Purchase | 200 | Peaking Unit Purchase | 200 |
| 2018 | | | | | | |
| 2019 | | | | | | |
| 2020 | | | | | | |
| 2021 | | | | | | |
| 2022 | PPA Contract Extension | 100 | PPA Contract Extension | 100 | PPA Contract Extension | 100 |
| 2023 | | | | | | |
| 2024 | Conventional Combined Cycle | 300 | PPA Contract Extension | 100 | Conventional Combined Cycle | 300 |
| 2025 | | | | | | |
| 2026 | | | PPA Contract Extension | 50 | | |
| 2027 | PPA Contract Extension | 50 | | | | |
| 2028 | | | Conventional Combustion Turbine | 100 | | |
| 2029 | | | | | | |
| 2030 | | | | | | |
| 2031 | | | | | | |
| 2032 | | | | | | |
| 2033 | | | Conventional Combustion Turbine | 100 | | |
| 2034 | | | | | Wind Power Purchase | 50 |
| Scenario NPV ($000) | | $ 4,517,265.00 | | $ 4,518,422.50 | | $ 4,519,879.00 |
| Percentage Above Low Cost Plan | | | | 0.03% | | 0.06% |

| | High Gas Prices Plan Rank 4 | | High Gas Prices Plan Rank 5 | |
|---|---|---|---|---|
| Year | Addition | MW | Addition | MW |
| 2015 | | | | |
| 2016 | | | | |
| 2017 | Peaking Unit Purchase | 200 | Peaking Unit Purchase | 200 |
| 2018 | | | | |
| 2019 | | | | |
| 2020 | | | | |
| 2021 | | | | |
| 2022 | PPA Contract Extension | 100 | PPA Contract Extension | 100 |
| 2023 | | | | |
| 2024 | PPA Contract Extension | 100 | Conventional Combined Cycle | 300 |
| 2025 | | | | |
| 2026 | PPA Contract Extension | 50 | | |
| 2027 | | | | |
| 2028 | Conventional Combustion Turbine | 100 | | |
| 2029 | | | | |
| 2030 | | | | |
| 2031 | | | | |
| 2032 | | | | |
| 2033 | Conventional Combined Cycle | 300 | | |
| 2034 | | | Conventional Combustion Turbine | 100 |
| Scenario NPV ($000) | | $ 4,521,201.50 | | $ 4,524,728.00 |
| Percentage Above Low Cost Plan | | 0.09% | | 0.17% |

**Table 30: High Gas Price Scenario – Five Lowest Cost Plans**

**Low Gas Price Scenario Optimal Plan**

The Low Gas Price scenario optimal plan includes the 200 MW Peaking Unit Purchase in 2017, followed by the addition of 300 MW of Combined Cycle capacity in 2022, 100 MW of Combustion Turbine capacity in 2031 and the purchase of 50 MW of Wind Power in 2034. This plan has an NPV of $4.01 billion over the period. The NPV's of the five least expensive Low Gas Price plans are within 0.4 percent of each other.

| | Low Gas Prices Plan Rank 1 | | Low Gas Prices Plan Rank 2 | | Low Gas Prices Plan Rank 3 | |
|---|---|---|---|---|---|---|
| Year | Addition | MW | Addition | MW | Addition | MW |
| 2015 | | | | | | |
| 2016 | | | | | | |
| 2017 | Peaking Unit Purchase | 200 | Peaking Unit Purchase | 200 | Peaking Unit Purchase | 200 |
| 2018 | | | | | | |
| 2019 | | | | | | |
| 2020 | | | | | | |
| 2021 | | | | | | |
| 2022 | Conventional Combined Cycle | 300 | Conventional Combined Cycle | 300 | Conventional Combined Cycle | 300 |
| 2023 | | | | | | |
| 2024 | | | | | | |
| 2025 | | | | | | |
| 2026 | | | | | | |
| 2027 | | | | | | |
| 2028 | | | | | | |
| 2029 | | | | | | |
| 2030 | | | | | | |
| 2031 | Conventional Combustion Turbine | 100 | Conventional Combustion Turbine | 100 | Conventional Combustion Turbine | 100 |
| 2032 | | | | | | |
| 2033 | | | | | | |
| 2034 | Wind Power Purchase | 50 | Conventional Combustion Turbine | 100 | Conventional Combined Cycle | 300 |
| Scenario NPV ($000) | | $ 4,009,812.50 | | $ 4,012,254.80 | | $ 4,017,726.80 |
| Percentage Above Low Cost Plan | | | | 0.06% | | 0.20% |

| | Low Gas Prices Plan Rank 4 | | Low Gas Prices Plan Rank 5 | |
|---|---|---|---|---|
| Year | Addition | MW | Addition | MW |
| 2015 | | | | |
| 2016 | | | | |
| 2017 | Peaking Unit Purchase | 200 | Peaking Unit Purchase | 200 |
| 2018 | | | | |
| 2019 | | | | |
| 2020 | | | | |
| 2021 | | | | |
| 2022 | Conventional Combustion Turbine | 100 | Conventional Combustion Turbine | 100 |
| 2023 | | | | |
| 2024 | Conventional Combustion Turbine | 100 | Conventional Combustion Turbine | 100 |
| 2025 | | | | |
| 2026 | Conventional Combustion Turbine | 100 | Conventional Combustion Turbine | 100 |
| 2027 | | | | |
| 2028 | | | | |
| 2029 | | | | |
| 2030 | | | | |
| 2031 | Conventional Combustion Turbine | 100 | Conventional Combustion Turbine | 100 |
| 2032 | | | | |
| 2033 | | | | |
| 2034 | Wind Power Purchase | 50 | Conventional Combustion Turbine | 100 |
| Scenario NPV ($000) | | $ 4,023,790.80 | | $ 4,026,494.20 |
| Percentage Above Low Cost Plan | | 0.35% | | 0.42% |

**Table 31: Low Gas Price Scenario – Five Lowest Cost Plans**

**Federal Environmental Legislation Scenario Optimal Plan**

The Federal Environmental Legislation scenario optimal plan includes the 200 MW Peaking Unit Purchase in 2017, followed by the extension of the 100 MW Power PPA contracts in 2022 and 2024, the extension of the 50 MW Power PPA contract in 2026, and 100 MW of Combustion Turbine capacity in 2028 and 2033. This plan has an NPV of $5.83 billion over the period, and is the highest cost scenario. The NPV's of the five least expensive Federal Environmental Legislation scenario plans are within 0.6 percent of each other.

| | Fed Environmental Plan Rank 1 | | Fed Environmental Plan Rank 2 | | Fed Environmental Plan Rank 3 | |
|---|---|---|---|---|---|---|
| Year | Addition | MW | Addition | MW | Addition | MW |
| 2015 | | | | | | |
| 2016 | | | | | | |
| 2017 | Peaking Unit Purchase | 200 | Peaking Unit Purchase | 200 | Peaking Unit Purchase | 200 |
| 2018 | | | | | | |
| 2019 | | | | | | |
| 2020 | | | | | | |
| 2021 | | | | | | |
| 2022 | PPA Contract Extension | 100 | PPA Contract Extension | 100 | PPA Contract Extension | 100 |
| 2023 | | | | | | |
| 2024 | PPA Contract Extension | 100 | PPA Contract Extension | 100 | PPA Contract Extension | 100 |
| 2025 | | | | | | |
| 2026 | PPA Contract Extension | 50 | PPA Contract Extension | 50 | PPA Contract Extension | 50 |
| 2027 | | | | | | |
| 2028 | Conventional Combustion Turbine | 100 | Conventional Combustion Turbine | 100 | Conventional Combined Cycle | 300 |
| 2029 | | | | | | |
| 2030 | | | | | | |
| 2031 | | | | | | |
| 2032 | | | | | | |
| 2033 | Conventional Combustion Turbine | 100 | Conventional Combined Cycle | 300 | | |
| 2034 | | | | | | |
| Scenario NPV ($000) | | $ 5,810,236.00 | | $ 5,811,490.50 | | $ 5,828,414.50 |
| Percentage Above Low Cost Plan | | | | 0.02% | | 0.31% |

| | Fed Environmental Plan Rank 4 | | Fed Environmental Plan Rank 5 | |
|---|---|---|---|---|
| Year | Addition | MW | Addition | MW |
| 2015 | | | | |
| 2016 | | | | |
| 2017 | Peaking Unit Purchase | 200 | Peaking Unit Purchase | 200 |
| 2018 | | | | |
| 2019 | | | | |
| 2020 | | | | |
| 2021 | | | | |
| 2022 | PPA Contract Extension | 100 | PPA Contract Extension | 100 |
| 2023 | | | | |
| 2024 | PPA Contract Extension | 100 | PPA Contract Extension | 100 |
| 2025 | | | | |
| 2026 | PPA Contract Extension | 50 | Conventional Combustion Turbine | 100 |
| 2027 | | | | |
| 2028 | Conventional Combustion Turbine | 100 | | |
| 2029 | | | | |
| 2030 | | | | |
| 2031 | | | | |
| 2032 | | | Conventional Combustion Turbine | 100 |
| 2033 | Integrated Gas Combined Cycle | 100 | | |
| 2034 | | | Wind Power Purchase | 50 |
| Scenario NPV ($000) | | $ 5,828,815.00 | | $ 5,843,152.50 |
| Percentage Above Low Cost Plan | | 0.32% | | 0.57% |

**Table 32: Federal Environmental Legislation Scenario – Five Lowest Cost Plans**

## 6.6 Conclusions

With the idling of the Ratts units, Hoosier Energy has a need for additional capacity in 2017. Factoring in the addition of planned renewable resources in the 2015 – 2020 timeframe, Hoosier Energy's next incremental capacity need is not forecasted to be until the early 2020's. The optimal online date for this capacity, as well as the type of resource, depends upon member load growth, environmental regulations and market price scenario. This recommendation reflects a least-cost strategy for Hoosier Energy which will allow it to retain flexibility should emissions regulations, load expectations and market prices change.

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

1. Hoosier Energy will use market purchases to meet short-term needs of 100 – 125 MW during the period from 2015 through 2017. It will also use hedging strategies to reduce market price risk and monitor markets for purchase opportunities.
2. Hoosier Energy will pursue a 200 MW sale from Merom beginning in 2018 to manage shaft risk. Other options include a slice-of-system sale and capacity swap.
3. Hoosier Energy will continue to develop Demand Side Management resources with its members. It will also pursue additional renewable energy opportunities consistent with the Board Policy standard of 10 percent of member energy requirements by 2025.
4. Hoosier Energy will evaluate its intermediate-term options to replace the 100 MW Duke Indiana PPA, which expires on December 31, 2017. Options to be considered include contract extension, long-term PPA with other parties, or buying or building capacity. It will also evaluate short-term opportunities to purchase peaking capacity in MISO as a hedge against market price increases and a future need for high-cost CT units.
5. Hoosier Energy will define its long-term needs for additional resources beyond 2020. Options include reliance on the market, extension of the Duke Indiana PPAs or acquisition of a physical resource.

An overview of the resource plan resulting from the screening process is summarized in Table 32 below. It should be noted that this plan does not include the recognition of any of the renewable resource capacity that will be added to Hoosier Energy's portfolio as the result of the change in its renewable resource Board Policy, which is referenced in Section 3.1.5. The Strategist model runs hundreds of scenarios to select an optimal, or least cost, combination of resources. It does not consider any other factors such as risk, potential market changes, regulatory/environmental considerations, etc. Management must evaluate the model results in conjunction with judgment about these other factors.

| Year | Retirements | MW | Additions | MW |
|---|---|---|---|---|
| 2015 | Ratts | 125 | Solar PPA | 10 |
| 2016 | | | Landfill Gas Unit | 16 |
| 2017 | | | Peaking Unit Purchase/Market Capacity | 200 |
| 2018 | Purchased Power Agreement | 100 | Purchased Power Agreement (net of new UC sale) | 76 |
| 2019 | Story County PPA | 25 | Wind PPA; Landfill Gas Unit | 54 |
| 2020 | | | | |
| 2021 | | | | |
| 2022 | | | Conventional CC | 300 |
| 2023 | | | | |
| 2024 | Purchased Power Agreement | 100 | | |
| 2025 | | | | |
| 2026 | Purchased Power Agreement | 50 | | |
| 2027 | | | | |
| 2028 | | | | |
| 2029 | | | | |
| 2030 | | | | |
| 2031 | | | Conventional CT | 100 |
| 2032 | | | | |
| 2033 | | | | |
| 2034 | | | Wind PPA | 50 |
| Total MW | | 400 | | 806 |

**Table 33: Preferred Resource Plan**