



**Draft Director's Report  
for the 2017 Integrated Resource Plans**

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IRPs submitted by Hoosier Energy, Indiana Municipal Power Agency,  
and Wabash Valley Power Association

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## 1. Introduction to Draft Director’s Report

This Draft Director’s Report discusses the 2017 integrated resource plans (“IRPs”) prepared by Hoosier Energy, Indiana Municipal Power Agency (“IMPA”), and Wabash Valley Power Association (“Wabash Valley”). The Director received no comments from stakeholders on the three 2017 IRPs because Hoosier Energy, IMPA, and Wabash Valley are not required to undertake a public advisory process during the IRP development. Investor-owned public electric utilities undertake multiple meetings with stakeholders and include those stakeholders in the development process. Instead, the unique governance structure of Hoosier Energy, IMPA, and Wabash Valley means that the Members of each of those organizations have the ability to influence the planning process in other ways. Further, the ratepayers of the individual Members of those organizations—i.e. the Members of the rural electric memberships cooperatives or the citizens of municipalities in IMPA—also have the ability to influence IRPs through their direct Member owned structure or the ballot-box in the case of municipalities.

Owing to the limited interaction with the IRP Director during the development of the IRP, this Draft Director’s Report will ask clarifying questions and raise process concerns to encourage continual enhancements to these utilities’ long-term resource planning. To that end, in this Report the Director has made comments on various aspects of the IRPs and asked sub-questions related to the comment. The Director also recognizes that load forecasting and consideration of demand-side management (“DSM”) and distributed energy resources (“DER”) requires a higher degree of coordination among the Member cooperatives and cities of these utilities due to the separation of responsibilities compared to vertically-integrated utilities. Given the stakes, however, we trust that Hoosier Energy, IMPA, Wabash Valley, and their Members, share common objectives. This report does not address all the questions, comments, and concerns raised by reading the IRPs from Hoosier Energy, IMPS, and Wabash Valley. The following list, however, necessarily addresses a multitude of topics, which are the primary focuses of this report:

- Load Forecasting
- Demand Side Management (DSM) Programs
- Interrelationships between Load Forecasting and DSM
- Resource Optimization and Risk Analysis

## 2. Hoosier Energy Integrated Resource Plan and Planning Process

Hoosier Energy's IRP is well reasoned and presented. However, Hoosier Energy faces significant questions about the future composition of their resource mix. Given the uncertainties and their attendant risks, the purpose of these draft comments is to challenge whether Hoosier Energy's long-term resource planning can be enhanced. The Director recognizes that the degree of vertical integration for Hoosier Energy, like Wabash Valley and IMPA, is not to the same degree that Indiana's investor-owned utilities are integrated. The Director recognizes Hoosier Energy and its Member cooperatives have strengths, such as greater local control, but the lack of integration with its Member cooperatives poses challenges regarding IRPs. The Director also recognizes that Hoosier Energy, like all other utilities in Indiana and the nation, is going through a transformation of the resource mix. Many of the issues addressed in the IRP are emerging and experience is too limited to make definitive recommendations.

### 2.1 Load Forecasting

Hoosier Energy compiles a 20-year (page 12) Power Requirements Study ("PRS") on a two-year cycle as required by the Rural Utilities Service ("RUS"). To better understand forecasting uncertainties and risks, Hoosier Energy said several forecast scenarios were developed allowing for review of the model's sensitivity to different economic and weather input assumptions. As a result, a Base Forecast, as well as six alternative load forecasts (i.e., "High", "Low", "Base-Upper Normal", "Base Lower Normal", "Base-Mild", and "Base-Severe"), were developed. (Pages 12 and 20). Hoosier Energy states that the load forecast provides a basis for determining generation, transmission, and distribution system modifications and capital investments. (Page 12). Hoosier Energy projects each Member's load and sums the load for each Member to derive the total load for Hoosier Energy. Each Member's system residential energy model is represented by three equations that are estimated simultaneously.

#### 2.1.1 Comment

The first equation projects the average electricity use per customer per month. The explanatory variables include the previous period's average electricity use per residential customer, the real average residential price of electricity, real average per capita income earned by people living in the service area, annual heating and cooling degree days, and other variables.

The second equation estimates the real average residential price of electricity. The explanatory variables include the average electricity use per customer per month, the actual real distribution system cost to

operate and maintain the distribution system excluding wholesale power costs, the average real wholesale cost of electricity paid by the Member cooperative, and other variables that may affect the price.

The third equation projects the number of residential customers. The primary explanatory variable is population in the service area. Other variables are included that may affect the number of customers. Hoosier Energy conducts a residential end-use survey to obtain end-use and consumer characteristics to better understand its consumers' demographics and electricity use. Each survey provides a snapshot of the residential consumer's appliance saturation and characteristics at a specific time. Continuous building and maintenance of survey databases provides insights into the development of future appliance and consumer characteristics. (Pages 29 and 30).

The commercial, industrial ("C&I") and other class energy forecast is based on a judgmental methodology. Use of the judgmental approach is based on four reasons (Page 14):

- Each cooperative provides a realistic potential growth estimate. These estimates are based on a review of past patterns, existing and near term developments, and expected future growth patterns.
- The erratic nature of the historical data make it difficult to explain growth in sales using an econometric model.
- The growth in this category is highly dependent on new developments rather than past patterns of growth.
- Growth can best be estimated by those most familiar with the area – the REMC managers and Hoosier representatives.

The base and six alternative load forecasts discussed previously were based on different economic and weather variables. For the residential forecast, the different forecasts were based on changes in population, real per capita income, fuel prices, and weather. For the C&I forecast, the different forecasts were differentiated based on variation in the number of customers and energy growth rates. Hoosier Energy said its goal was to make changes to the variable assumptions that resulted in alternative scenarios representing conditions that could *realistically occur*. (Page 20).

The following factors were considered to determine the range of changes in the variables driving the forecasts (Page 20):

- Observed changes in the explanatory variables over the historical period that the forecast is based on.

- 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).

#### 2.1.1.1 Question

The residential energy sales' three equations all include "other" explanatory variables that are not explained or discussed. Would Hoosier Energy please provide more details?

#### 2.1.1.2 Question

The C&I forecasts were developed by surveying individual Members. Such surveys tend to be inaccurate in the long-term because the people surveyed have no basis for long-term changes. The Director recognizes the difficulty of projecting C&I load over long periods of time. Has Hoosier Energy considered developing more sophisticated modeling for C&I customers to enhance the credibility of the forecasts? Would Hoosier Energy agree the credibility of C&I forecasts necessitates that a range of load forecasts be developed to adequately represent the uncertainty inherent in the C&I sector?

### 2.1.2 Comment

It is unclear to the Director how well the load uncertainty was addressed even when Hoosier Energy used low- and high-load forecasts based on different economic assumptions. Four other forecasts were developed using the base forecast with varying weather conditions represented by alternate parameters for heating degree days and cooling degree days. The intent was to develop an upper bound and a lower bound on normal weather.

### 2.1.3 Comment

While the alternative scenarios are meant to represent conditions that could *realistically occur* this may unduly limit Hoosier Energy's consideration of legitimate risks. Ten years ago, for example, the prevailing wisdom was that natural gas prices would be much higher today. Three years ago, there was a reasonable likelihood the Clean Power Plan would be implemented. Consistently, the Director has urged utilities to consider low probability events that have significant ramifications if those events are realized.

#### 2.1.3.1 Question

Has Hoosier Energy considered the potential ramifications of what would happen to Hoosier Energy resource planning if the largest customer(s) left – leaving or perhaps installing their own generation resources? What would happen if Hoosier Energy added a significant new load(s)? While electric

vehicles may be more common in urban areas, would Hoosier Energy agree that, over the 20-year planning horizon, Hoosier Energy may see significant changes due to electric vehicles or other innovations?

#### 2.1.3.2 Question

The discussion on weather normalization in section 2.2.6 of the Hoosier Energy IRP refers to the historical period for determining normal weather (including the upper and lower ranges), but Hoosier Energy does not identify what that period is. How many years of weather history has Hoosier Energy used in the load forecast?

#### 2.1.4 Comment

On page 20 of its IRP, Hoosier Energy describes the most probable energy forecast as the Base-Normal case. The Base-Normal case was developed using the most likely assumptions. The alternative load forecasts were developed after the Base-Normal case was completed. Despite the Base-Normal case being based on the most likely assumptions, Hoosier Energy decided to use the Base-Upper Normal weather scenario as its base case. Hoosier Energy said the Base-Upper Normal forecast delivered the best fit when compared to Hoosier Energy's 2016 actual load.

##### 2.1.4.1 Question

Is there a reason to think 2016 weather was normal (e.g., representative of the next 20 years)? If not, isn't Hoosier Energy essentially calibrating its forecast to an atypical year? Also, it should be noted that the only difference between the Base-Upper Normal forecast and the Base-Normal forecast is a constant shift in the weather variable throughout the forecast period. Wouldn't this mean the Base-Normal forecast is shifted up to develop the Base-Upper Normal forecast?

#### 2.1.5 Comment

The load forecast presented is from the 2017 PRS prepared for the RUS. (Pages 12 and 13). But much of the analysis in the resource optimization and integration section of the IRP is based on the 2015 PRS because that was the most recent forecast available when much of the IRP analysis was being done.

##### 2.1.5.1 Question

The Director appreciates that the timing of the PRS and the IRP was awkward, but has Hoosier Energy considered the potential ramifications for a *stale* load forecast on the results of the IRP analysis?

## 2.1.6 Comment

The calculation of system coincident peak demand and load factor was based on historical information from 1975 to 2015. (Page 18). However, over the last 10 or so years, most utilities have observed that peak demand was growing at a faster rate than energy use. The prevailing explanation is the effect of energy efficiency.

### 2.1.6.1 Question

Has Hoosier Energy considered that a long-term trend may be masking more recent trends? That is, if coincident peak demand grows more than energy use, this may provide an expanded opportunity for demand response or distributed energy resources (“DER”) that is not captured in the longer history. By way of examples: ever-increasing efficiencies of appliances/end-use technologies, changes in customer acceptance of demand response or DER, electric vehicles, or other technological changes, may result in changes in both demand and energy use that will further alter the load factor and the relationship between coincident peak and non-coincident peak demands.

## 2.1.7 Comment

It appears the consumer surveys are only for residential customers, but there is not a great deal of information about how these surveys were conducted or how they were integrated into the load forecast.

### 2.1.7.1 Question

If that is correct and given the Hoosier Energy appreciation for the value of the surveys, has Hoosier Energy considered expanding the surveys to commercial and, even, industrial customers? What is the survey method?

### 2.1.7.2 Question

With the industry move to Advanced Metering Infrastructure, has Hoosier Energy considered changes to the survey instrument to collect more detailed appliance/end-use data and better demographic information to improve the explanatory value of the load forecast?

### 2.1.7.3 Question

Consistent with the IRP’s expectation of continued enhancements to load forecasting and the IRP generally, what areas of its load forecasting process does Hoosier Energy anticipate improving for future IRPs?



## 2.2 Demand Side Management

### 2.2.1 Comment

Hoosier Energy states it tries to attain an accurate DSM program performance forecast using a two-part process. The first part requires estimating a realistic forecast on a short-term basis, tied to the most recent market potential study completed by an outside consulting firm. This study incorporates data updated with actual DSM performance through the most recent completed year and the addition of new programs. The second part incorporates Hoosier Marketing Department staff meeting with each Member system to develop estimated forecasts, making adjustments as needed, and discussion of long-term forecast impacts. The expected base level impact of DSM programs for the 20-year planning horizon is incorporated by Hoosier Energy into the load forecast, considering the number of forecasted participants, current program costs, projected energy program savings, and projected winter and summer demand savings.

Hoosier Energy also conducts an assessment of potential additional DSM using a Levelized Cost of Energy (“LCOE”) analysis. Each DSM measure is grouped into DSM portfolios and the collective potential of the portfolio to reduce the cost to serve load is projected. Hoosier Energy worked with a consultant to develop an estimate of the potential increased penetrations of each measure. Using the current and projected participant counts of each measure, Hoosier Energy calculated additional participants for each DSM measure. The growth in participant counts was limited to one-half of the annual energy growth forecast. For example, if the annual energy growth forecast was 1%, then the number of additional participants was limited to 0.5% growth above the current participation level.

Each measure’s additional energy savings were projected by multiplying the per-measure energy savings by the number of additional participants each year. Measure costs were projected by multiplying the per-measure cost by the number of additional participants for each year. Each measure’s aggregated energy were multiplied by the projected Base Case market pricing used in the IRP analysis.

According to the IRP (page 91), the cases with the additional DSM participation did not achieve enough avoided energy or capacity to avoid or defer a new generic resource, presumably on the supply-side.

### 2.2.2 Comment

It is difficult to tell whether demand-side and supply-side resources were optimized simultaneously in the IRP long-term resource planning model and without pre-selection of certain resources. A base level of demand-side resources was predetermined and included in the load forecast. Additional DSM was evaluated using a LCOE Analysis, but it is unclear if the additional DSM was included as a selectable

resource in the resource integration process. Additional DSM is not mentioned as a selectable resource in the resource integration and optimization portion of the IRP.

#### 2.2.2.1 Question

In Hoosier Energy's IRP analysis, were only supply-side alternatives included as resources to be optimized in the modeling or were supply and demand-side resources optimized simultaneously? Was a base level of demand-side resources predetermined and included in the load forecast? If a base level of DSM was estimated, it is not clear how the expected base level of demand-side resources was estimated. Would Hoosier Energy please elaborate?

#### 2.2.2.2 Question

Consistent with the IRP's expectation of continued enhancements to DSM, what areas of Hoosier Energy's DSM process does Hoosier Energy and its Member systems anticipate improving for future IRPs?

### 2.3 Interrelationships between Load Forecasting and DSM:

#### 2.3.1 Comment

There is a one paragraph discussion of DSM in the load forecast section (page 26), but there is little discussion of how the effects of energy efficiency and demand response programs are accounted for in the load forecast. The interrelationship between the load forecast and the impact of DSM programs is further confused by the discussion of demand-side resource analysis on pages 88-91. On page 88, Hoosier Energy states the expected base level of demand-side resource programs for the 20-year IRP timeframe have been incorporated into the load forecast used by Hoosier Energy in the IRP. Unfortunately, the discussion on page 88 does little to help a reader understand how the load forecast is modified to account for the impact of DSM.

#### 2.3.1.1 Question

Would Hoosier Energy please provide additional discussion to help us understand how DSM was integrated into the load forecast?

## 2.3.2 Comment

It is unclear how all or any of the eight DSM portfolios are incorporated into the load forecast presented by Hoosier Energy in its IRP. The source of confusion is because the forecasted annual energy savings numbers presented in Appendix G, for example, do not seem to add up to the numbers presented in Appendix A2, “DSM EE program Energy with DSM impacts” table, for the base scenario.

### 2.3.2.1 Question

Could Hoosier Energy please provide additional commentary?

## 2.3.3 Comment

Consumer surveys for residential customers should be a valuable source of information for designing, evaluating, and measuring and verifying the effects of DSM programs. However, it is not clear from the IRP how the survey information was used in the DSM programs or the load forecasts.

### 2.3.3.1 Question

Could Hoosier Energy please provide an expanded discussion to clarify?

### 2.3.3.2 Question

Also, with the industry’s move to Advanced Metering Infrastructure, has Hoosier Energy considered changes to the survey instrument to collect more detailed appliance/end-use data and better demographic information to improve the program design (including rate design), evaluation, measurement, and evaluation process for DSM?

## 2.4 Resource Optimization and Risk Analysis

PA Consulting (“PA”) was hired by Hoosier Energy to conduct an assessment of the long-term viability of existing resources from both an operational and economic perspective. This analysis served as the basis for the 2017 IRP. The assessment also identified potential future resources, and the associated cost and operational parameters, to be included in the integrated system modeling process.

PA used the AURORAxmp model in an iterative process for the long-term planning for the MISO area. The AURORAxmp modeling process yielded projected market prices for MISO Zone 6, where Hoosier Energy is located. PA then used these market prices to develop the projected dispatch and market revenues for each owned and contracted resources, as well as future candidate resources.

An internally developed model was used by PA to simulate each asset's dispatch that treats the prices of power and fuels stochastically. Upon completion of the asset dispatch simulations, the final step in the process was to employ PA's portfolio optimization model to find the least cost portfolios based on a 20-year net present value of the power supply revenue requirements.

Hoosier Energy started with six market scenarios. They are: 1) Base Case; 2) Coal Upside; 3) Partial Upside; 4) Partial Downside; 5) Coal Downside; and 6) Low Gas scenarios. For each market scenario, a corresponding stress case was created, which assumed additional expense in mid-2020s and increased escalation of annual fixed operations and maintenance ("O&M") and capital expenses on the Merom plant. Then, each of the 12 cases was combined with three tolerance levels for market demand and energy exposure – high tolerance, base tolerance and low tolerance. This results in a total of 36 discrete scenarios for Hoosier Energy. These scenarios are referred to by Hoosier Energy as Future Worlds scenarios.

The scenarios described above were based on the Hoosier Energy load forecast from the 2015 PRS, as that was the most recent forecast available at the time. Subsequent to the modeling of these original scenarios, Hoosier Energy completed and released an updated load forecast – the 2017 PRS. The scenario modeling described above was not updated with the 2017 PRS load information, because the differential in summer peak demand between the two PRS reports is only approximately 20-30 MW and thought unlikely to change the modeling results.

### 2.4.1 Comment

Notwithstanding the timing problems in the PRS and IRP, Hoosier Energy did elect to use the 2017 PRS in modeling some additional scenarios.

- Base Case– Using Base Upper Normal load scenario from the 2017 PRS
  - Base Case – same assumptions as the Future Worlds Base Case scenario with the load forecast updated to include the 2017 PRS
  - Alternative Gas Scenario – Gas prices 20% lower than included in the Base Case
  - Carbon Scenario – Regional Greenhouse Gas Initiative ("RGGI")-level prices beginning in 2022
- Low Load – Using the Low Economic load scenario from the 2017 PRS

- Base Case – same assumptions as the Future Worlds Base Case scenario with the load forecast updated to include the 2017 PRS
- Alternative Gas Scenario – Gas prices 20% lower than included in the Base Case
- Carbon Scenario – RGGI-level prices beginning in 2022
- Merom Capital Costs 10% higher than in Base Case
- Renewables Costs 10% lower than in Base Case

Each scenario was run using market tolerance levels of both +/-5% and +/-10%.

## 2.4.2 Comment

As discussed above, DSM resources do not appear to have been included as a selectable resource in the resource optimization portion of the IRP modeling. Specifically, Hoosier Energy does not explain how they treat DSM as a resource. We ask Hoosier Energy to elaborate.

### 2.4.2.1 Question

Does Hoosier Energy agree with this assessment?

## 2.4.3 Comment

The names of the alternative scenarios, especially the Future World scenarios, are not intuitive. It is very difficult to connect the name with the assumptions in the scenario. Could you help us understand how are the assumptions regarding anti-fracking gas regulations, high capital cost, and diminishing renewable demand related to a scenario titled “Partial Upside?” In addition, the interactions between macro-economic factors, environmental regulations, energy prices, fuel prices, capital costs, regional market and cyber-attacks do not make logical sense in a certain scenario (e.g., how the limited social pressure on coal/emissions with delayed environmental regulations decreases coal prices in the Coal Upside Scenario.

### 2.4.3.1 Question

What is the basis for assuming that short-term power price spikes resulted from cyber-attacks on the U.S./MISO electric grid in the Coal Upside Scenario? It is concerning that the definition and description of various scenarios is very confusing.

## 2.4.4 Comment

On page 94, Hoosier Energy states it used a discount rate of 5% to calculate the net present value of the resource plans. But for the DSM plans the LCOE analysis used a 7.2% discount rate. The use of either specific discount rate is not explained nor why the two rates differ.

### 2.4.4.1 Question

Could Hoosier Energy please provide a rationale for the two discount rates and how the differences might have affected the IRP analysis?

## 2.4.5 Comment

The supplemental scenarios based on the 2017 PRS are shown at a high level in Table 30 on page 88. The results are discussed in only a couple of sentences and primarily note that the most economic resource plans all have Merom operating through 2040. There is almost no explanation of how the information developed from the Future World scenario results is used except to note that one half of the scenarios show that the Merom generation station remains economic through 2040.

### 2.4.5.1 Question

In Table 29 on page 86, Hoosier Energy presents modeling results for only 12 of the 36 scenarios developed. Is there a reason that the other scenarios were not discussed?

## 2.4.6 Comment

The preferred resource plan is discussed (pages 92-96). There is a discussion of how the Preferred Plan meets planning criteria including least cost, reliability, risk, and flexibility, but there is no discussion of how the preferred plan was derived from the large amount of modeling results.

## 2.4.7 Comment

It is not clear how the fuel price projections shown in Tables 20 and 21 tie back to the detailed price projections in Appendix D. For example, the Stress Scenarios shown in Table 21 appear to be in Appendix D, but the gas price projections for the Future Worlds Scenarios do not appear to be in Appendix D.

## 2.4.8 Comment

With regard to risk analysis, Hoosier Energy stated that risks are addressed through sensitivity cases in the modeling process. Hoosier Energy incorporated different resource alternatives, market conditions,

load growth, and future environmental regulations into the modeling process to provide a range of scenarios and outcomes. However, Hoosier Energy noted it is not possible to predict and capture all risks and the models are simply another tool for management to employ to make resource decisions. The Director agrees with Hoosier Energy that it is not feasible to consider all potential risks. However, given the concerns about the names and characterization of the scenarios, it is not clear that scenarios and portfolios that might be regarded as having reasonable probabilities of occurrence were included. Moreover, Hoosier Energy's restrictive definition seems to have excluded scenarios and their portfolios that have relatively low probabilities but significant ramifications if realized.

#### 2.4.8.1 Question

What enhancements is Hoosier Energy considering making to databases, scenario development, risk analysis, portfolio naming conventions, enhanced surveys, more discrete load data, and the IRP process generally for future IRPs?

## 3. Indiana Municipal Power Agency’s Integrated Resource Plan and Planning Process

### 3.1 Initial Comments:

IMPA does not face an immediate need for significant amounts of new resources which affords IMPA an opportunity to carefully assess future resource options with considerable optionality. The state-of-the-art, long-term resource planning tools such as AURORAxmp, the commitment to Advanced Metering Infrastructure (“AMI”), and IMPA’s participation in both the MISO and the PJM, provide significant resource options.

#### 3.1.1 Comment

At the outset, one of the Director’s concerns was IMPA’s request for confidential treatment. Even after a series of correspondence from the Commission expressing concern that IMPA seemed to rely heavily on EIA as a significant input into their analysis but classifying this public domain source as “confidential.” Section 6 – Resource Options – IMPA stated that assumptions for fossil-fueled options come from Energy Information Administration (“EIA”) on page 46 but then redacted them and placed them in Appendix E. For future IRPs, because maximum transparency should be a hallmark of the IRP process, the Director urges IMPA to document the justification for confidential treatment to provide greater assurance that public domain information is not inappropriately classified.

### 3.2 Background

IMPA operates in both the MISO and PJM regions.

In 2017, IMPA's coincident peak demand for its 61 communities was 1,128 MW, and the annual member energy requirements during 2017 were 6,098,477 MWh. IMPA projects that its peak and energy will grow at approximately 0.5% per year. These projections do not include the addition of any new members or customers beyond those currently under contract. Since the last IRP was filed, IMPA has added one new member, the Town of Troy, Indiana. Additionally, in August of 2017, the Village of Blanchester, Ohio, which had been an IMPA customer since 2007, became an IMPA member. (Page 1-11).



...In total, IMPA's generation and contractual resources reside in eight (8) different load zones in Indiana, Illinois, Iowa and Kentucky.<sup>1</sup> This diversity reduces IMPA exposure to forced outages, locational marginal prices (LMPs), zonal capacity rates and regional fuel costs. (Page 1-12).

IMPA is projecting "extremely low prices of capacity and energy through 2027" (Page 1-14) and IMPA's minor need for resources will largely be met by market purchases of wind and solar. In 2025, if the Base Case is unchanged, the Whitewater Valley Station ("WWVS") may be retired and, potentially, partly replaced by an Advanced Combined Cycle generating unit. (Page 1-13).

### 3.2.1.1 Question

IMPA states on Page 1-12 that its members are in eight load zones, but throughout its IRP, there is only discussion of five load zones. Could IMPA please explain?<sup>2</sup>

IMPA's energy efficiency program offers incentives in the form of rebates for residential and commercial and industrial (C&I) customers. Since 2012, IMPA's energy efficiency programs generated a cumulative savings of 115,864 MWh at the end of 2017 and a coincident peak reduction of 12.8 MW. In addition to its energy efficiency program, IMPA offers a demand response tariff, a net metering tariff, education and training. Furthermore, many IMPA members utilize various rate structures aimed at assisting customers in lowering or controlling their energy consumption or bills. (Page 1-12).

## 3.3 Load Forecasting

Because IMPA serves members in eight different zones, IMPA develops a 20-year projection of peak demands and annual energy requirements for each zone. The load forecast is developed using a time-series, linear regression equation for forecasting both energy and expected peak demand across IMPA's five load zones. IMPA's experience showed the primary drivers to be: total households, energy intensity

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<sup>1</sup> IMPA's supply-side resources include: Joint ownership interests in Gibson Unit 5 (in Indiana), Trimble County Units 1 and 2 (in Kentucky), Prairie State Units 1 and 2 (in Illinois); Operation and maintenance responsibilities for Whitewater Valley Units 1 and 2; Seven combustion turbines wholly owned by IMPA; 17 solar parks located in IMPA member communities; Generating capacity owned and operated by one of IMPA's members; Long-term power purchases from I&M and Duke Energy Indiana, as well as short term purchases from various utilities and power marketers in the MISO and PJM energy markets. Crystal Lake Wind Energy Center in Hancock County, Iowa. (Page 4-21).

<sup>2</sup> IMPA operates in both the MISO and PJM RTOs. IMPA has load in five IOU load zones and generation resources connected to seven IOU zones within the RTO footprints, plus two resources outside of the RTOs. IMPA's load is divided approximately 2/3 MISO and 1/3 PJM.

(Btu / \$ of real GDP) from the EIA, economic factors from the St. Louis Federal Reserve Bank such as Real Gross Domestic Product (national not state or regional data), household debt, and Indiana non-farm payrolls. Additionally, IMPA gave consideration to potential policy changes, heating and cooling degree days as well as peak/off peak days, future technologies such as penetration of new or emerging technologies (e.g., electric vehicles), and end user investment in efficiency products such as energy efficient appliances or smart thermostats. (Page 4-31).

### 3.3.1 Comment

IMPA mentioned that it considered a “dummy variable”<sup>3</sup> for the June through August peak season, as well as dummy variables to isolate peak day conditions intra-month. (Page 5-31). However, IMPA mentioned on page 5-34, Table 9, that dummy variables were used in Duke-IN, NIPSCO, and AEP load zones.

#### 3.3.1.1 Question

Based on Table 5, page 31, it appears that IMPA incorporated the above-mentioned dummy variables for some load zones. Is this correct? If so, given that there was a variable for Peak and Off-Peak and other time and temperature related variables, what was the rationale for considering a dummy variable? For example on Table 5, page 31, it isn't obvious that a dummy variable is a useful indicator for both peak days and peak seasons within the same model.

#### 3.3.1.2 Question

The references to Tables 8 and 9 seem inconsistent. Table 8 appears to be for energy models but the last sentence of the first paragraph on page 34 refers to Table 9 for energy models and the last sentence of the next paragraph refers to Table 8 for peak models.

#### 3.3.1.3 Question

What does IMPA mean by: “On/Off Peak Days” as a variable (Page 33, Table 8)? Is this the number of peak days vs. off-peak days? It appears this is based on page 35 “Calendar inputs (e.g., peak days per month) which were determined using a calendar and adjusted for holidays.” How is this done? If so, is it correct that some “peak days” may actually be non-holiday weekdays? From the information provided, it is not clear.

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<sup>3</sup> Explanatory variables are often qualitative in nature (e.g., wartime versus peacetime), so that some proxy must be constructed to represent them in a regression. Dummy variables are used for this purpose. A dummy variable takes the value of one whenever the qualitative phenomenon it represents occurs, and zero otherwise.

#### 3.3.1.4 Question

What is the purpose of developing spring and fall peak models (page 34)?

#### 3.3.1.5 Question

IMPA mentioned it also considered expected daily load, temperature, wind speed, barometric pressure, and intra-day temperature deviations. Did IMPA give effect to any of these factors? If so, what was IMPA's rationale?

#### 3.3.1.6 Question

Do IMPA communities obtain any detailed demographic information to supplement the total household data? If not, have IMPA or its member cities considered conducting a survey using a random but representative sample from its member cities?

#### 3.3.1.7 Question

Do IMPA communities provide any detailed end-use/appliance information to supplement the energy intensity analysis? In other words, does IMPA have any empirical data to support the 2% annual rate of decline in energy intensity according to the International Energy Agency's 2016 report "Energy Efficiency Market Report: 2016?" (Page 5-35). Table 10 shows projections for Real GDP Growth. The Organization for Economic Cooperation and Development ("OECD") is consistently higher than the other sources.

#### 3.3.1.8 Question

Did IMPA consider that relatively optimistic projections of real GDP might result in an upward bias for the forecast and, ultimately, for long-term resource planning, especially if some of the other variables were optimistic? The Director appreciates the difficulty in finding objective and quality data sources but is concerned with using International Energy Agency's OECD-wide projection of changes in energy intensity. This data source may be questionable because the factors driving intensity (prices and personal income) are probably very different in many OECD nations and may be less representative of a specific state. Also, nations with tight labor markets may have increasing intensity while those that do not may have decreasing intensity.

#### 3.3.1.9 Question

Kudos to IMPA and its member cities for installing AMI. Consistent with the IRP rule to strive for continual improvement, how does IMPA plan to utilize the wealth of information from AMI to provide more detail to enhance the load forecasting?

#### 3.3.1.10 Question

What geographic region (state/census region/national) is used for the economic variables? IMPA specifically states “Indiana Non-Farm Income” but what about GDP and household debt?

#### 3.3.1.11 Question

If household debt and Indiana non-farm payroll are driven solely off GDP, why not just use GDP as the driver in the energy models since both of those variables will change at the same rate that GDP does? (Page 35 – Section 5.4).

#### 3.3.1.12 Question

What is the source for the assumed GDP growth rates in the low- and high-growth scenarios (Page 41 – last paragraph)?

#### 3.3.1.13 Question

We understand that IMPA believed that national data on real GDP and non-farm incomes provided a better *fit* in the regression analysis than regional and state data, (Page 5-35). How did IMPA come to that conclusion?

#### 3.3.1.14 Question

What changes to load forecasting has (or is) IMPA considering to enhance the explanatory values and credibility of their load forecasting processes?

### 3.3.2 Comment

IMPA continues to contend that end-use load forecasts would not be seriously considered:

Another forecast methodology is end-use. The data requirements for an end-use model are extensive. They include detailed information on appliance saturations and usage patterns in the residential sector, data on building and business types in the commercial sector and detailed equipment inventories, lighting types, and square footage area in the industrial sector. IMPA’s member communities are not uniform, they contain various ages of homes and businesses. The age of the residents and vintage of the houses can have a significant impact on the saturation of various appliances. To collect the proper saturation data at the member level, IMPA would need to collect a valid sample of each member’s customers. Given the fact that IMPA would need to sample a substantial portion of its members’ retail consumers to achieve a statistically valid sample, end use

sampling is unreasonable for IMPA to implement. Therefore, IMPA cannot realistically utilize this type of a forecast model. (Page 5-44).

The Director fully recognizes that perfect information is not possible and that costs and benefits of better load forecasts need to be carefully considered. That is, IMPA may well be right that the credibility and explanatory value might not warrant end-use load forecasting, even with the recognition it would have to be gradual. Perhaps, the opportunity for better Evaluation, Measurement, and Verification (“EM&V”) of energy efficiency, demand response and customer-owned or other DERs such as storage – maybe to improve the distribution systems - might tip the balance. Especially since resource planning is long-term in nature, maybe the potential for lower uncertainties and attendant risks, when combined with other benefits and sunk costs of AMI would warrant end-use load forecasting. As the need for new capacity increases, the importance of load forecasting and better evaluation of all resources becomes more critical. The Director’s concern is not that end-use load forecasting should be the goal. Rather, it is the improved information that can benefit a wide range of analysis and improve the credibility of the analysis. As IMPA improves its data bases, perhaps, it could work with other utilities to improve data quality and quantity.

### 3.4 Energy Efficiency

In 2011, approximately 90 companies and 25 communities participated in the first year of IMPA’s energy efficiency program. Incentives were offered for: energy efficient lighting; heating, ventilation and air conditioning (“HVAC”); motors, fans & drives; and refrigeration, food service and controls. In 2012 and 2013, IMPA voluntarily participated in Energizing Indiana, a statewide energy efficiency program in order to gain experience and evaluate the cost-effectiveness of a variety of residential, commercial, and industrial programs. The savings from these efficiency efforts was 32 million kWh (2012) and 52.7 million kWh (2013) annually. However, in 2014 IMPA returned to self-management of the energy efficiency programs, believing it to be more cost-effective. (Page 4-25). Through the end of 2017, IMPA’s energy efficiency programs have generated a cumulative savings of 116,000 MWh and a coincident peak reduction of approximately 12.9 MW. (Page 4-29).

#### 3.4.1 Comment

Despite the success of energy efficiency there is no energy efficiency in the Base Expansion plan. (Page 13, Table 1).

#### 3.4.1.1 Question

Is the above characterization correct? If so, would IMPA please explain how a significant amount of energy efficiency is not included in the Base Expansion plan?

#### 3.4.1.2 Question

If energy efficiency is not in the Base Expansion plan, is it correct to assume that energy efficiency was not treated in a manner that is as “comparable as possible” to other resources in IMPA’s long-term resource planning?

### 3.4.2 Comment

IMPA seems to affirm it will continue offering diverse incentives options as part of the energy efficiency program but does not really provide a detailed explanation on how the savings are incorporated in the scenarios development. Furthermore, this IRP does not clearly show a projection of future energy savings or load reductions coming from the different tools used to determine the incentives of IMPA’s energy efficiency program.

#### 3.4.2.1 Question

Consistent with the IRP rule requiring continual improvements, does IMPA plan to use its AMI to enhance EM&V for energy efficiency? If so, please provide details. Does IMPA and its member cities also plan to supplement the discrete load data available from AMI with appliance/end-use surveys that also include demographic information?

## 3.5 Demand Response

### 3.5.1 Comment

IMPA's members implemented demand response programs including: coincident peak rates; off-peak rates; power factor improvement assistance; load signals to customer-owned peak reduction or energy management systems; advanced meter infrastructure/automatic meter reading and streetlight replacement with more efficient lamps. (Page 4-29). However, on page 28 IMPA states that it has no customers participating in the demand response programs and Table 1 on page 13 does not show that demand response is in the Base Expansion plan.

#### 3.5.1.1 Question

If IMPA did not include demand response in the Base Expansion plan, is it correct to assume that demand response was not treated in a comparable manner to other resources in IMPA's long-term resource planning?

#### 3.5.2 Comment

There is limited explanation about the reasons to have no customers participating in the demand response tariffs program. It would be beneficial to conduct an evaluation to determine the causes for this lack of participation or what, if any, plans IMPA and its member cities have to increase participation.

#### 3.5.2.1 Question

Consistent with the IRP rule requiring continual improvements, does IMPA plan to use its AMI to enhance the credibility of its EM&V for energy efficiency? If so, please provide details. Does IMPA and its member cities also plan to supplement the discrete load data available from AMI with appliance/end-use surveys that also include demographic information?

### 3.6 Interrelationships between Load Forecasting and DSM

Comment: It is not clear how energy efficiency or demand response were modeled and whether energy efficiency and demand response were real options (allowing the model to objectively select the resource) or whether the selection of a specific amount or percentage of energy efficiency and demand response was pre-specified (hardwired). (Section 6.3).

#### 3.6.1.1 Question

If IMPA did not pre-specify a certain amount of energy efficiency and demand response, could IMPA please explain how energy efficiency and demand response were modeled and optimized within the IRP?

#### 3.6.1.2 Question

Is our understanding correct that the member communities are now in charge of the administration of energy efficiency and demand response? If so, do the members conduct the EM&V of energy efficiency and demand response? If this is accurate, can IMPA attest that EM&V is conducted consistently and in the same manner as IMPA would have done it if they were still a part of the statewide energy efficiency program?

### 3.7 Resource Optimization and Risk Analysis

IMPA evaluates the performance of the different optimized portfolios that emanate from the scenarios using a variety of stochastic analysis on important drivers such as fuel costs, market prices, capital costs, load changes, and environmental regulations. (Page 3-18). In this IRP, as in the prior IRP, IMPA has provided excellent discussions of risk analysis.

IMPA's Preferred Plan was derived from scenario and risk analysis. In the near term, IMPA expects to take advantage of low price bi-lateral capacity market prices to fulfill capacity obligations in MISO rather than building new generation. Also, the Preferred Plan called for additional wind in 2019 and in 2026. This would allow IMPA to maintain optionality by layering into a policy hedge, in effect, while also preserving the ability to take a "wait-and-see" approach with respect to carbon and other environmental policy, which was identified as an influential driver putting upward pressure on cost in the risk analysis. The short-term action plan is very consistent with the preferred plan selected.

IMPA utilized the AURORA<sub>xmp</sub> to generate market capacity expansion studies, market price studies and portfolio optimization. Then MCR-FRST by MCR Performance Solutions, LLC was used to develop the final revenue requirements for each portfolio. Risk analysis was conducted with a variety of analytical tools and techniques, including decision trees, risk profiles, tornado charts, and trade-off diagrams.

IMPA modeled the entire Eastern Interconnection in its expansion planning, with special focus on the two largest areas with the most interconnectedness - PJM and MISO. A complete regional capacity expansion plan and the corresponding wholesale price for energy and capacity were determined for each scenario. The regional capacity expansion plan generated a list of eligible assets for selection for IMPA to create the optimized portfolio under each scenario. The market prices for capacity and energy from the regional capacity expansion plan were used as inputs in the IMPA's portfolio optimization as well.

Risk analysis and scenario development are a critical element of developing a robust set of portfolios.

IMPA identified three distinct themes which were expected to have the greatest impact on the future energy business environment over the next 20 years. The three cases are Base Case, Green Case, and Robust Growth/De-regulation Case. All IMPA-owned units were given the opportunity to retire in the capacity expansion runs. Especially since IMPA doesn't anticipate the need for significant new resources in the next few years, the bandwidth for risk seems appropriate (e.g., Economic Growth, Capital Costs, RPS, and Reserve Margin).



### 3.7.1 Comment

However, there appears to be no explicit discussion of the possible effects of innovation or changes such as electric vehicles, despite being mentioned on page 5-31. The natural gas price projections seem to be on the high side and do not seem to have significant downside risk. It seems likely that natural gas prices, especially compared to coal, will be a significant driver and may alter the resource decisions. In short, it would not have been unreasonable for the range of risks to be a little more expansive. For example, what happens if IMPA adds (or loses) a significant load or significant amounts of DERs locate within IMPA communities?

It would also not be unreasonable for a sensitivity that shows lower economy growth or slightly higher economic growth, but very minor changes in the projected economic growth may not drive resource decisions in the longer-term.

**Table 15 Expansion Results – 3 Plans**

| <i>Case Comparison and MW Additions/Subtractions by Year</i> |                  |                        |                                    |
|--|------------------|------------------------|------------------------------------|
| <i>Drivers</i>   | <i>Base Case</i> | <i>Green Case</i>      | <i>Robust Growth/De-regulation</i> |
| <b>Economic Growth</b>                                       | 2.1%             | 1.5%                   | 2.6%                               |
| <b>Capital Costs</b>   | Reference        | Reference              | Reference                          |
| <b>Load Forecast</b>   | IMPA Base Case   | IMPA Reference -3.3%   | IMPA Reference +3.2%               |
| <b>Natural Gas Prices</b>                                    | Reference        | Base +35% (on average) | Reference +32%                     |
| <b>Coal Price</b>  | Reference        | Reference +2%          | Reference +6%                      |
| <b>CO2 Policy</b>  | \$20/Ton in 2026 | \$40/Ton in 2026       | None                               |
| <b>RPS</b>   | No               | 20% by 2030 w Phase In | No                                 |
| <b>Reserve Margin</b>  | Reference Area   | Reference Area         | Reference Area                     |

AURORAxmp contains an integrated risk model, which allows parameters such as volatility and cross commodity correlation being developed and entered into AURPRAxmp risk framework. Using this risk model, each candidate portfolio was evaluated for robustness given uncertain outcomes. Each plan was evaluated by a tornado chart and graph showing iterative outcomes in average system cost across time and risk thresholds over iterations, Average System Rates (“ASR”) efficient frontier, present value revenue requirements, ASR risk confidence bands, ASR S-Curves and carbon dioxide emissions were used to compare across plans.

### 3.7.2 Comment

IMPA's discussion of the *dark spread* and *spark spread* analysis is informative and makes it clear why coal struggles in the competitive market based economic dispatch of MISO and PJM. (Pages 70-72).<sup>4</sup>

### 3.7.3 Comment

IMPA states that PJM has a higher Base Case growth rate, but on page 65 it lists it at 0.3% for energy and 0.2% for demand (as compared to page 64 with MISO at 0.76% and 0.65%, respectively). Thus, PJM has a lower Base Case growth rate, not higher. (Page 86 – last paragraph).

#### 3.7.3.1 Question

If this is a mistake, does this affect the IRP given IMPA's statement in Section 13 on page 127: *“The asset selection for the IMPA portfolio is dependent on the output of the Aurora zonal expansion module under the assumption that whatever is most efficient for the RTO should provide IMPA a set of diverse and rational asset choices for its own portfolio. In other words, if a resource is not built in the RTO expansion study, it cannot be considered for IMPA's portfolio (unless that resource is already an existing resource).”*

### 3.7.4 Comment

As an observation, IMPA's expansion options are limited to those selected in the PJM (or more broadly in the Eastern Interconnection) expansion. This may be consistent with the global optimum, but it could be sub-optimal locally.

### 3.7.5 Comment

IMPA uses the forward price as its forecast price in the short-term (2018-2023). (Page 73 Figure 27). Forward prices generally reflect a risk premium, so they are not expected to match spot prices. The difference may be small since both buyers and sellers may be hedging risk to different degrees. It appears IMPA uses the forward prices in the long-term with prices for 2030 and beyond being derived from extrapolation. (Page 76 – Figure 29 and Section 10.3.3).

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<sup>4</sup> Would IMPA agree with the following definitions of dark spread and dark spread? Dark Spread is the positive (or negative) difference between the market price of electricity and the cost of coal-fired generation. The spread can be measured by the difference between the spot or forward prices. Spark spread is the positive or negative difference between the market price (spot or forward) of electricity and its cost of production using natural gas. A positive spark spread means the company profits from selling generation into the market. A negative spark spread means the utility company loses money.

### 3.7.5.1 Question

For figures 23 - 30 (e.g., Indiana Hub On-peak Dark Spread), the Director assumes these are in nominal dollars. Is this correct? Is it correct to say that the resource planning analysis was not adversely affected by using nominal dollars rather than real dollars?

### 3.7.5.2 Question

Options are used for natural gas price volatility rather than market prices. IMPA states that “Once market implied volatility is no longer available, IMPA transitions to a gradually declining term structure.” Would IMPA please clarify on what is meant by this sentence and how it affects IMPA’s resource decisions?

## 3.7.6 Comment

The Director recognizes the difficulty in predicting future environmental policy. It seems IMPA had no carbon tax for most iterations (page 152 High Growth Case Results). Specifically, IMPA states it “allowed for a handful of iterations to illustrate a modest carbon tax.” Thus, the carbon dioxide risk is low (Figure 109). This looks like the assumption is driving the outcome. The Director expects the risk of being wrong about carbon dioxide prices to be most significant in this case, but IMPA does not allow that to happen by making its low carbon tax assumption. Also, in contrast to IMPA’s assumption, it would seem reasonable to expect all of the risk to be on the high side since the carbon price is zero in the baseline, positive in some cases, and never negative.

### 3.7.6.1 Question

What are IMPA’s thoughts on the above comment?

## 3.7.7 Comment

Table 11 on page 41 does not show a jump in peak demand in the load forecast section. However, this seems to be contradicted in Section 16.

### 3.7.7.1 Question

In Section 16 regarding IMPA’s Plan Selection, it is not clear what is driving the jump in Peak + Reserves from 2033 to 2034 (see Table 18 and Figure 117).

## 4. Wabash Valley Power Association's Integrated Resource Plan and Planning Process

Wabash Valley's IRP was well done and well presented. The purpose of the Draft comments is to challenge whether things can be done better, not just be done differently. The Director recognizes that the degree of integration for Wabash Valley, like Hoosier Energy and the IMPA, is not to the same degree that Indiana's investor-owned utilities are integrated. The Director recognizes Wabash Valley has strengths such as greater local control but the lack of integration with its Member cooperatives poses challenges regarding IRPs. Wabash Valley provides service in three states and six sub-balancing areas. The Director also recognizes that Wabash Valley, like all other utilities in Indiana and the nation, are going through a transformation of the resource mix and many of the issues addressed in the IRP are emerging and experience is too limited to make definitive recommendations.

### 4.1 Wabash Valley's Load Forecasting

At the outset, the Director appreciates Wabash Valley's candor that prior forecasts for its 23 Member cooperatives over-stated its energy and demand growth. To Wabash Valley's credit, they took action to improve the credibility of its forecasts by retaining ITRON. The Director recognizes that all forecasting methods can over (or under) estimate load growth (or loss) and Wabash Valley should be commended for its critical review and its efforts to improve its load forecasting processes. Additionally, Wabash Valley's leadership in installing AMI is commendable. Is it correct to assume this is part of the Distributed Energy Management System ("DERMS") discussed on Page 25? As with the use of AMI for DSM (Power Shift program on Page 25) it can enhance the credibility of Wabash Valley's billing and analysis, and integrating AMI data into the load forecasting would be consistent with the IRP's draft rule that requires continual improvement. The load forecast schematic (Page 38 Figure 3-1) was helpful:

Upon review of Power Requirements Studies produced over the last decade, Wabash Valley concluded that we have been consistently over-forecasting energy and demand when using our existing load forecasting methodology. To improve our forecast, in late 2016 the Company engaged Itron, a technology and services company with expertise in energy forecasting, to develop a new load forecast modeling framework for Wabash Valley and its Member systems utilizing Itron's MetrixND® regression modeling software and Forecast Manager™ database. After initial development by Itron, the Company's Budgets and Forecasting department analyzed the preliminary load forecast results. Wabash Valley then refined the estimated models and assumptions based upon

information and insights from varied internal resources. The Company's Board approved the final 2017 Power Requirements Study (PRS) for use in the 2018 Budget and 2017 IRP as our Base Case Load. (Section 3 page 37)

### 4.1.1 Comment

For Wabash Valley, it is gratifying they appreciate the inherent risks of being a Generation and Transmission ("G&T") Cooperative and losing or gaining membership and limited duration contracts. "The exit of three Members and the economic recession have had a significant impact on the load forecasts" in the last 6 years. (Pages 39 and 55). Because the possibility of gaining or losing Members is a substantial risk to Wabash Valley, additional detail as to how the high- and low-load forecasts were developed would be helpful. In future IRPs, having a better understanding of this risk of losing Members (or attributable to DER or loss of a large load) and the effect on the high and low forecasts would be useful. (Page 54).

### 4.1.2 Comment

Wabash Valley's recognition that obtaining more granular usage and other information on its ultimate customers would enhance the credibility of Wabash Valley's load forecast process is also noted. (Page 37). Graph 3-3 (Page 39) and Graph 3-4 on (Page 40) highlight the risks of over-forecasting (of course there are significant risks and potential costs associated with under-forecasting). Overall, the techniques used to model and forecast the residential customers' energy requirements seem reasonable.

Hopefully, AMI will provide additional information that is useful in preparing the forecast to enhance its explanatory value and credibility, especially if the AMI data is supplemented with on-going residential appliance/end-use surveys. It is commendable that Wabash Valley's Residential Survey continues to ask participants about their "awareness and interest in distributed generation. Approximately 1% of survey participants have installed some form of on-site generation and another 10% have seriously considered installing it. This is a slight increase over the 2015 survey." (Page 13).

4.1.2.1 Question Since Wabash Valley has successfully utilized residential survey instruments to get appliance data as well as distributed generation data, does Wabash Valley plan to extend the surveys to commercial customers for appliance/end-use data as well as their interest in DER? Has Wabash Valley considered asking demographic information and other relevant information to enhance its understanding of their ultimate customers?

#### 4.1.2.2 Question

What changes have been made to the forecasting procedure to reduce the potential for over-forecasting Wabash Valley's load requirements other than using ITRON to develop the forecast?

#### 4.1.2.3 Question

Consistent with Wabash Valley's concern that prior forecasts have systematically over-forecast energy and demand, could Wabash Valley please provide some additional information to help us better understand Table 3-2, Table 5-4, and Graph 5-6? That is, the load forecast summer peak shows consistent growth in Table 3-2, while the power supply requirements in Table 5-4 show a slight drop (15 MW) from 2027 to 2028. Furthermore, Graph 5-6 shows a much larger drop (about 200 MW) in peak demand at that same time. The IRP does not reconcile these discrepancies or explain the drop in Graph 5-6. (Pages 39, 79, and 81).

#### 4.1.3 Comment

The Director understands Wabash Valley's forecast process is the summation of the individual Member systems. The total load for each Member system is modeled using an econometric model. (Pages 43-44). The model includes an economic activity index, a weather index, and a weighted energy intensity term that reflects the Member residential/commercial customer mix, service area economy and the geographic location. The projected number of residential customers in a given year is multiplied by the projected average use per residential customer for that year to derive the total residential load for that Member. The other load is projected using a trend analysis or an exponential smoothing methodology.<sup>5</sup> Thus, a Member's total load is projected along with separate projections of residential and other customer class load.

According to the IRP, energy sales and peak demand for commercial customers were developed by the staff of each Wabash Valley Member cooperative using historical trends and information made available by the individual customers. This information includes expansions, new construction, and business closures etc., but it is not clear how this information is integrated into the load forecast. Specifically, the commercial forecast is derived from subtracting the residential and other forecast from the total forecast because the historical data does not support forecasting commercial directly. On Page 48, it seems that C&I loads are obtained by simply subtracting Residential and Other from total retail sales. As a result,

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<sup>5</sup> Would Wabash Valley agree with the following definition of exponential smoothing as one form of smoothing technique used to in forecasting to reduce irregularities (random fluctuations) in time series data, thus providing a clearer view of the true underlying behavior of the series?

C&I is not modeled. So, any error in the Residential or Other forecast modeling will affect the C&I forecast.

#### 4.1.3.1 Question

Wabash Valley states “Commercial sales forecasts are consistent with forecast assumptions.” (Page 48). Would Wabash Valley please explain what this means and how it affects the load forecast if the C&I forecast is determined as a remainder?

#### 4.1.3.2 Question

Since Wabash Valley’s Members have historic billing information by month for each of the residential Members and the data needed to forecast “Other,” couldn’t Wabash Valley use this information to derive the commercial history? Given the relatively few industrial customers, wouldn’t this information be readily available? With the approach Wabash Valley uses, only the total forecast really matters. It appears that the balance of the forecast is merely divvying up the total. Is this an accurate characterization? (Page 45 – Section 3). With the better load data, has Wabash Valley thought about revamping its load forecasting methodology?

#### 4.1.3.3 Question

Since “small and large commercial revenue classes are not specifically modeled” (Page 48), how does the following statement affect the forecast “commercial sales forecast is lower as both the GRP [Gross Regional Product] and household projections are lower than in the 2010 to 2016 period?” Similarly, how does the forecast utilize the following information: “Commercial sector end-use intensity projections are expected to decline as a result of federal energy efficiency standards and technological improvement in light, refrigeration, heating, and cooling?” (Page 48).

#### 4.1.3.4 Question

With respect to the previous questions, on Page 42, would Wabash Valley please provide a brief explanation of what is meant by “(spot load adjustments) to account for specific expected expansions and retractions of large commercial load.” How is this integrated into the forecast?

### 4.1.4 Comment

According to the IRP, Wabash Valley assessed forecasted energy, peak, and sales growth rates for consistency against household, gross regional product, energy intensity trends and combinations of these variables. Given strong historical and projected efficiency gains, long-term energy requirements track lower than regional economic growth projections. At the individual Member level, annual energy

requirements for 2018 to 2036 average between 0.0% to 1.9% growth; coincident peak demand growth averages between 0.1% and 1.9%. The range of these average growth rates reflects the diversity of our Member systems. (Page 47).

#### 4.1.4.1 Question

Based partially on the previous comment, is it a correct assumption that the reason historical class peak loads are not available is because Wabash Valley doesn't forecast C&I, rather than the lack of metering data that could provide this information? If so, wouldn't historical billing information be useful if Wabash Valley were to forecast C&I customers? Has Wabash Valley considered the value (e.g., added credibility for the forecast, better information for system planning and designing rates) of forecasting the contribution of each class to Wabash Valley's system peak? Do any of Wabash Valley's Members forecast their peak demand or their coincident peak demand with Wabash Valley? If so, does Wabash Valley give effect in the forecast?

#### 4.1.5 Comment

Despite Wabash Valley's explanation in this IRP and its previous IRP, the Director continues to struggle with understanding the forecasting and planning distinctions and potential ramifications between non-conforming and conforming loads.

#### 4.1.5.1 Question

Is it correct to say that "pass-through" loads are non-conforming loads and these loads take on the attendant financial responsibilities of arranging for power purchases and ancillary services *to customize their power supply portfolio based on their respective risk tolerances*? Is it also correct "[T]he large power customers are included in Wabash Valley's total planning load because the Company has the ultimate responsibility to meet the large power customers' energy requirements and make purchases at market to meet the minimum reliability requirements." (Page 42).

#### 4.1.6 Comment

If our understanding of Pass-Through Loads is correct that Wabash Valley has financial and resource planning obligations for these loads, it would seem that all Wabash Valley's customers assume some of the risks for these customers. Even if the risk is deemed to be minor by Wabash Valley, it makes the lack of rigor in the forecasting and resource planning for these customers difficult to understand. If Wabash Valley assumes some risk for non-conforming loads, it doesn't seem credible that pass-through loads are projected to remain constant in the long term (see Table 3-10) and are excluded from the regular forecast.



Constant projected loads over the 20-year planning horizon means that the forecast never sees any additions or subtractions from large loads in the future. Especially since two customers were recently moved to being non-conforming status, forecasting constant loads may not be reasonable even in the short run. This seems particularly problematic in the longer term since that is when Wabash Valley is more likely to consider new resources. Placing sole reliance for forecasting these customers' needs on Member cooperative staff – no matter how expert and diligent - seems unduly risky. Would Wabash Valley be amenable to providing a more detailed explanation of the Pass-Through Loads and their potential ramifications for Wabash Valley? If Wabash Valley acknowledges that a more rigorous forecast is appropriate for non-conforming customers, would Wabash Valley consider scenarios and sensitivities to better capture the risk and uncertainty? (Page 42 – Section 5).

#### 4.1.6.1 Question

Would Wabash Valley explain the rationale and ramifications of using binary variables to account for unexplained data? Using binary variables without an accompanying rationale raises a red flag. (Page 45 – Section 4).

#### 4.1.6.2 Question

The load forecast summer peak shows consistent growth in Table 3-2, while the power supply requirements in Table 5-4 show a slight drop (15 MW) from 2027 to 2028. Furthermore, Graph 5-6 shows a much larger drop (about 200 MW) in peak demand at that same time. Would Wabash Valley be able to reconcile these discrepancies and explain the drop in Graph 5-6? (Pages 39, 79, 81)

## 4.2 Wabash Valley's DSM Programs

### 4.2.1 Comment

Wabash Valley's intention is to treat DSM on as comparable a basis as possible with other resources (Pages 23 and 63) but, as discussed below, it is not clear that this was done. Wabash Valley states they have 55 MW under load control in its PowerShift program (Page 24 detailed on Page 22 as including: water heaters, air-conditioners, pool pumps, irrigation, grain dryers, ditch pumps, and entire homes). Wabash Valley noted its Demand Response programs started in 1981 with direct-load control (DLC) for residential water heaters and its energy efficiency programs began in 2008 with the Touchstone Energy Home Program.

Table 2-12 presents historical MWh savings of the selected programs but there is no information about the programs corresponding MW savings. Since these programs are later compared with other supply resources, an explanation on how the energy was converted to demand (e.g. the source of the load shapes) and the amount considered by program would benefit the readers and provide a better understanding of the modeling process.

However, the future of energy efficiency and demand response isn't clear from the brief information Wabash Valley provided in its IRP (below). While it appears that Wabash Valley considered discrete demand response and energy efficiency programs the discussion does not say how Wabash Valley intends to evaluate, select, optimize, and utilize energy efficiency and demand response.

Wabash Valley's planning and evaluation of DR and EE programs is highly dependent upon a collaborative process with its Members. Input from the Members is invaluable for the process of evaluating existing programs, collecting information on program implementation, gaining information on the program's technical and economic potential and customer acceptance of new programs. The Company has both a Demand Response Committee and an Energy Efficiency Committee that are comprised of Members' personnel.

For Wabash Valley's 2017 IRP, we are evaluating our demand-side resource options on a comparable basis to our supply-side resources. For DR, we utilized current internal 2017 Integrated Resource Plan cost estimates based on recent experience building out our programs. For EE, we obtained high-level program cost estimates from a condensed study of achievable efficiency potential. These demand-side alternatives' projected capacity and operating costs are presented in Table 4-3 Demand-Side Expansion Plan Alternatives. (Page 64).

**TABLE 4-3 Demand-Side Expansion Plan Alternatives – DR and EE  
(Stated in 2017 dollars)**

| Unit                                  | 1-MW<br>DR | 1-MW<br>Residential<br>EE | 1-MW<br>Small Comm<br>EE | 1-MW<br>Large Comm<br>EE |
|---------------------------------------|------------|---------------------------|--------------------------|--------------------------|
| <b>Installed Capital Cost (\$/kW)</b> | \$344      | \$1,371                   | \$441                    | \$441                    |
| <b>Typical Load Factor</b>            | 1%         | 60%                       | 60%                      | 60%                      |
| <b>Capacity Cost (\$/kW-month)</b>    | \$2.23     | \$8.88                    | \$2.86                   | \$2.86                   |
| <b>Fixed Cost (\$/kW-month)</b>       | \$4.92     | \$0.00                    | \$0.00                   | \$0.00                   |
| <b>Avg. Total Cost (\$/MWh)</b>       | \$978.75   | \$20.27                   | \$6.52                   | \$6.52                   |

Despite Wabash Valley’s statement “For Wabash Valley’s 2017 IRP, we are evaluating our demand-side resource options on a comparable basis to our supply-side resources,” it wasn’t clear if demand response or energy efficiency was co-optimized with other resources such that PLEXOS was able to select DSM when it was warranted. If PLEXOS determined objectively that DSM was warranted, it is not clear how Wabash Valley or its Members would implement future DSM.

#### 4.2.1.1 Question

How were energy efficiency and demand response resource alternatives developed and analyzed on as comparably to other resources as reasonably feasible? For example, based on prior IRPs, we understood Wabash Valley incorporates demand response measures as part of the power supply portfolio and approached them as a resource (treated similar to a peaking plant.) Therefore, demand response is chosen after competing with other most economic supply-side resources which may not reflect the full value of demand response for Wabash Valley or its Members under several possible events.

#### 4.2.2 Comment

Until 1986, each Wabash Valley Member used load management to reduce its non-coincident peak billing demands. In 1986, Wabash Valley centralized control of the demand response program to reduce system coincident demand and reduce overall system costs. With the development of RTO markets, in 2011 Wabash Valley created two riders to allow C&I customers the opportunity to participate in MISO’s Emergency Demand Response program and PJM’s Emergency Load Response program.

#### 4.2.2.1 Question

Does Wabash Valley and its Members have any intention of seeking to expand the MISO and PJM programs? How wide is the participation?

#### 4.2.3 Comment

For energy efficiency, Wabash Valley engaged NAVIGANT to assist Wabash Valley throughout the planning, design, and EM&V of the various programs. For 2017, Wabash Valley’s goal was to reduce energy use by 34,277 MWh and an avoided power supply cost of \$17,268,000. Wabash Valley implemented a DERMS to provide customer usage data in five minute intervals and analyze the avoided use by utilizing an historic baseline. (Page 25). This should enhance Wabash Valley’s EM&V process for demand response.

#### 4.2.3.1 Question

Given the implementation of DERMS, how did this system enhance the development of load shapes for the demand side resource alternatives developed from the individual measure characteristics? Is DERMS suitable for providing more granular information for energy efficiency programs and their effect on demand reduction as well as energy use?

#### 4.2.3.2 Question

An issue of concern is the method of offering different energy efficiency measures in a single resource group. The use of this methodology would reduce the ability to capture potential differences in cost and load characteristics between measures within each group. Has Wabash Valley considered this concern? If so, how?

### 4.3 Interrelationships between the Load Forecast and DSM

Wabash Valley and its Member cooperatives have developed several DSM programs that seem to be well designed and offer Wabash Valley's Members opportunities to control their electric usage for the mutual benefit of the customers and the Wabash Valley system. For purposes of this IRP, however, the future DSM programs and how they affect the load forecast is more important, especially since Wabash Valley has acknowledged that prior forecasting methods resulted in over-forecasting the Wabash Valley system requirements

#### 4.3.1 Comment

While the historical programs appear to be well-designed, it is not clear that Wabash Valley's approach to DSM and the complex interrelationships with the load forecast and future demand-side resources is captured by Wabash Valley. This is despite Wabash Valley's comment "*[p]otential Demand Response (DR) and future program-related energy efficiency (EE) savings are treated as a resource rather than a reduction to load*". (Page 43). Wabash Valley's discussion does not clearly state how its state-of-the-art planning tool PLEXOS integrates DSM into the forecasting or resource planning process to treat all resources on as comparable a basis as possible.

#### 4.3.1.1 Question

Is it possible that energy efficiency is being double counted in the Wabash Valley load forecast? Is it also possible that Wabash Valley's is still over forecasting Wabash Valley's electric requirements by not giving full consideration to how DSM and the load forecast affect each other?

#### 4.3.1.2 Question

Has the MISO or PJM called upon emergency demand response from other utilities but not called upon Wabash Valley’s emergency demand response? If so, is it possible that revisions could be made to increase the benefit of the DR program?

#### 4.3.1.3 Question

On Table 2-1, Page 10, the qualifier for coincident demand states “Coincident demand includes pass-through load but excludes interruptible load.” For clarity, does this mean that Member load was interrupted at the time of each winter and summer peak? On Table 3-2 on Page 39, does the coincident demand also exclude interruptible customers?

#### 4.3.1.4 Question

Regarding the Base Resource Plan and Scenario Results – A total of exactly 50 MW of energy efficiency is selected consistently across all portfolios (note the timing varies). Is this the result of a pre-selected limit on available energy efficiency? (Pages 69, 74-79).

## 4.4 Resource Optimization and Risk Analysis

### 4.4.1 Comment

Wabash Valley developed a reasonable base case and three alternative scenarios that seem to be well reasoned. Wabash Valley then used a sequence of scenario analysis <sup>6</sup>and stochastic analysis to test *each alternate expansion plan against several combinations of stochastic variables to determine how each plan performed against an unknown future.* (Page 72). The stochastic analysis was used to review the potential effects of various risk components on the resource plans developed under the various scenarios. This seems to be an appropriate method of utilizing stochastic analysis.

Wabash Valley said the risk components included load – both peak demand and energy; market prices for wholesale electric power, natural gas, and coal; and the potential for an eventual carbon tax. However, in reviewing the stochastic analysis, it was not clear if Wabash Valley included correlation among the stochastic variables. For instance, higher natural gas prices may result in higher market prices.

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<sup>6</sup> The scenarios included: (1) The Base Expansion Plan; (2) the High Economic Growth Expansion Plan; (3) Low Economic Growth Expansion Plan; (4) Carbon Expansion Plan with Coal Retirement Option; (5) Renewable Cost Improvements Expansion Plan.

## 4.4.2 Comment

The Director appreciates that Wabash Valley acquired the PLEXOS modeling system just months before the 2015 IRP. It is not clear how the use of PLEXOS affected the 2017 IRP, since much of the input for the modeling seems to be largely unchanged since the 2015 IRP.

### 4.4.2.1 Question

Consistent with the draft IRP rule for continuing improvements, does Wabash Valley anticipate changes to the processes to make better use of the AMI data, information on DSM, and PLEXOS capabilities?

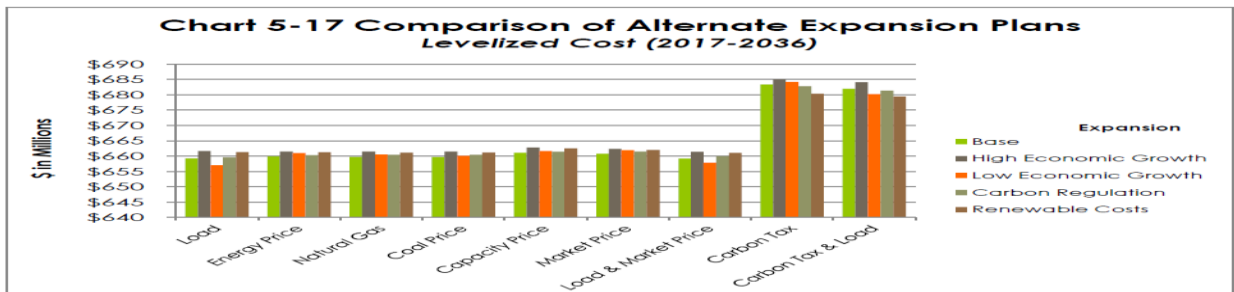
## 4.4.3 Comment

The sensitivities on Chart 5-17, page 91, are difficult to understand since there is no discussion of how the table was prepared. For example, how is the levelized cost for the different risk factors calculated across the horizontal axis? Also it is not clear how the information in Chart 5-17 affected the IRP, influenced management decision making, or were helpful to Wabash Valley’s attainment of the “objective of Wabash Valley’s IRP is to develop a resource portfolio that minimizes the long-run cost of providing service to our Members while delivering that service at levels consistent with prudent utility practice and acceptable risk levels.”

Since the Y Axis scale is intentionally reflective of costs in excess of \$650 million and the differences among the alternative expansion plans are not significant, it is not clear what inferences would be drawn. It might be that load might be very different if Wabash Valley were to lose or gain a Member.

### 4.4.3.1 Question

If the natural gas prices had a wider range of prices, would there be more separation in the analysis? How would the Expansion Plans change if there was a wider stochastic analysis of market price? A reasonable reading of this chart could be that, if there was a carbon tax, the least risky Expansion Plan would be to rely more heavily on renewable resources.



#### 4.4.3.2 Question

Would Wabash Valley discuss, in greater detail, how these apparent stochastic sensitivities were used in the consideration of the portfolios that emanated from the Base Case and the four other scenarios?

#### 4.4.4 Comment

With regard to risk and uncertainty analysis, the Director agrees with Wabash Valley that “[i]n the electric utility industry as a whole and specifically at Wabash Valley, managing enterprise risk is a high priority. Wabash Valley’s Board identifies the Company’s risk management objectives and provides risk management oversight.” (Section 1, Page 1). To this end, Wabash Valley offered four scenarios in addition to the Base Case. (Page 72 and 91).

#### 4.4.4.1 Question

Given Wabash Valley’s experience with fluctuating membership and the increasing potential for DERs and the loss (or gain) of new customers, would it have provided useful insights to expand the load forecasts bandwidth for all of the scenarios? (Page 54).

#### 4.4.5 Comment

The Director believes the following scenarios are reasonable with well-reasoned narratives. However, for future IRPs as the risks to Wabash Valley and its Members increase as new resources are being considered, does Wabash Valley intend to increase the range of risks by including consideration of relatively low probability but highly consequential outcomes if realized? To Wabash Valley’s credit, Wabash Valley has a diverse portfolio and has demonstrated a willingness to purchase power from other entities if warranted by savings in the delivered cost of electricity.

#### 4.4.5.1 Question

To help explain how Wabash Valley intends to mitigate risk, would Wabash Valley describe how it anticipates procuring future resources?

### 4.5 Base Case

#### 4.5.1 Comment

Wabash Valley built a base scenario on the 2017 base case load forecast, assumptions about lower natural gas prices, liquid capacity market for short-term needs and no carbon price. It is noted that Gibson Unit 5 retirement was not considered an option in the modeling.

#### 4.5.1.1 Question

What was the rationale for Gibson 5 retirement not being a selectable option? From the discussion of energy efficiency and demand response and the use of Plexos, is it accurate to say that energy efficiency and demand response were treated on a reasonably comparable basis to other resources and optimized? If no, please say why? If energy efficiency and demand response were modeled and optimized with other resources, please provide a brief description of how this was done, beyond the brief descriptions on pages 63-67.

## 4.6 High Economic Growth

### 4.6.1 Comment

In the high economic growth case, energy requirements will grow by 1.1% per year, reaching 8,868 GWh by 2036. The high economic growth energy forecast is 3.9% higher than the base case forecast in 2036. Under this scenario, summer coincident peak demand also grows by 1.1% per year, reaching 1,794 MW in 2036. The high economic growth demand forecast is 4.3% higher than the base case forecast in 2036.

#### 4.6.1.1 Question

Consistent with prior questions, is it conceivable that Wabash Valley's load will be greater (perhaps a new Member, electric vehicles, etc.)? While Wabash Valley's forecast range seems reasonably expansive, what was Wabash Valley's rationale for the ranges used in this scenario, beyond the brief description on page 54? Would Wabash Valley agree that it is possible that greater incremental energy efficiency is possible in the High Economic Growth environment (beyond the amount in Table 5-1 on page 74)? Did Wabash Valley consider conducting any stochastic analysis to see the implications of greater energy efficiency? Similarly, did Wabash Valley consider demand response? Were DERs considered?

## 4.7 Low Economic Growth

### 4.7.1 Comment

In the low economic growth case, energy requirements will grow by 0.6% per year, reaching 8,059 GWh by 2036. The low economic growth energy forecast is 5.5% lower than the base case forecast in 2036. Under this scenario, summer coincident peak demand also grows by 0.6% per year, reaching 1,616 MW in 2036. The low economic growth demand forecast is 6.0% lower than the base case forecast in 2036.



#### 4.7.1.1 Question

Also consistent with prior questions, suppose Wabash Valley experiences lower growth than anticipated in this scenario (perhaps due to a loss of a Member or major load, or customer-owned distributed generation). Would Wabash Valley agree that it is possible that some incremental energy efficiency is possible in the Low Economic Growth environment? Did Wabash Valley consider that keeping energy efficiency at “0” might be unrealistic and conduct any stochastic analysis to see the implications of greater energy efficiency?

#### 4.7.1.2 Question

For future IRPs, does Wabash Valley intend to expand the risk of lower than expected load growth? Similarly, did Wabash Valley consider demand response? Were DER considered?

## 4.8 Carbon Regulation and Renewable Costs

### 4.8.1 Comment

With regard to the potential costs associated with carbon regulation, based on Wabash Valley’s risk analysis, carbon tax seems to be the most influential factor. In this scenario, Gibson 5 was retired in 2030, which seems reasonable. Similarly, retaining the Prairie State unit due to its lower operating costs that “*more than offset the carbon tax*” seems reasonable.

#### 4.8.1.1 Question

Is this Wabash Valley’s interpretation? If so, why doesn’t Wabash Valley’s Action Plan show increased activity in cultivating energy efficiency, demand response, renewables, and other non- or low-carbon emitting resources in order to hedge such risk. In short, how were the results of risk analysis incorporated into the Action Plan and longer-term resource planning?

#### 4.8.1.2 Question

On page 77, Wabash Valley mentioned that a carbon tax of \$7.78 / ton in 2030 was imposed. The tax increased to \$26.30 / ton in 2036. Did Wabash Valley conduct stochastic sensitivities to determine the point of inflection for higher carbon taxes to change (higher and lower carbon tax) the retirement decisions?

## 5. 2017 IRPs Summary and Conclusions

The IRPs prepared by Hoosier Energy, IMPA, and WVPA are, overall, well-reasoned and well-presented documents. However, as with all IRP analysis, there is room for improvement. That is, the potential for improvement in these IRPs is not dissimilar from that for other Indiana utilities' IRPs. In this regard, there are important differences and similarities that are worth noting.

Against the backdrop of projections for very slow growth in electric sales over the next 20 years, all utilities confront considerable uncertainties, risk, and significant financial ramifications. Hoosier Energy, IMPA, and Wabash Valley, like others in Indiana, the region, the Eastern Interconnection, and the nation are all anticipating dramatic changes in the resource mix in the next several years due to the projected lower cost of natural gas compared to coal, the declining cost of renewable resources, the retirement of coal-fired units – particularly those that are older and smaller and face on-going environmental costs, the increasing utilization of energy efficiency, and demand response, and the increasing capability to purchase power (and sell power) over vast distances due to Regional Transmission Organizations such as the Midcontinent ISO (“MISO”) and the PJM. Both the MISO and the PJM project low wholesale power market prices for the next few years. Increasingly, all utilities will be integrating DERs and new technologies into their systems. Some of these technologies will reduce electric use and others, like electric vehicles, will increase electric use but the net ramifications are not known.

As a result of the risks and uncertainties, Hoosier Energy, IMPA, and Wabash Valley seem to be maintaining considerable flexibility in their short and longer-term planning. Each utility has a unique approach that best suits the judgment of their respective managements.

To their credit, all of these utilities recognize the enormity of the issues and their potential consequences. For this reason, they are all utilizing state-of-the-art long-term resource planning tools such as AURORAxmp and PLEXOS. Since these tools are relatively new to these utilities, they may not have tapped the full potential of these planning models. Additionally, few utilities have the databases to fully utilize the power of these modeling tools. To remedy some of the data limitations, these utilities are, to varying extents, replacing old electro-mechanical meters with Advanced Metering Infrastructure.

While Hoosier Energy, IMPA, and Wabash Valley all recognize the more likely risks, they all seem reticent, to varying degrees, to consider low probability events that have significant consequences if realized. This reticence was evidenced in the construction of scenarios, sensitivities, and the resulting resource portfolios. In particular, IMPA provided an excellent discussion of risks and risk analysis. Moreover, all three made an effort to integrated probabilistic (stochastic) analysis into their planning process. However, it was not

always clear how the probabilistic analysis was incorporated into each utility's IRP and each utility's Preferred Portfolio. For example, while Hoosier Energy provided a convincing analysis that the Merom Plant is economic through the planning horizon in most of the scenarios, little more is known about the potential benefits, costs, and risks implications.

Hoosier Energy, IMPA, and Wabash Valley, to different degrees, included discussions of how DSM was modeled and projected but it was unclear how energy efficiency was included in the load forecast and it is not clear whether DSM was included as a selectable resource, if at all, in the optimization modeling. It was also unclear whether any of the three utilities co-optimized their DSM with other resources on as comparable a basis as possible. The Director is not saying the methodology used by Hoosier Energy, IMPA, and Wabash Valley was *wrong*. Rather, the discussion left room for interpretation as to how DSM analysis was performed and used.

It was unclear how each of these utilities' planning was affected by MISO's and PJM's operations and planning. By way of examples: if some resources are retired, is it possible that these utilities could increase their reliance on short-term market purchases rather than committing to build new resources? Is it possible that MISO and PJM open-up new markets that were previously not available? Is it possible that the information about long-term resources throughout the MISO and PJM regions could provide useful information that could influence the long-term resource planning by Hoosier Energy, IMPA, and Wabash Valley? At a minimum, could Hoosier Energy, IMPA, Wabash Valley, benefit from MISO's and PJM's expertise in setting up well-reasoned scenarios, understanding sensitivities, making effective use of probabilistic analysis, and making the most effective use of modeling expertise. MISO and PJM should also realize benefits due to the increased confidence of Hoosier Energy, IMPA's, and Wabash Valley's load forecasting and long-term resource planning. Among other things, an argument can be made that the MISO's and PJM's reserve margins could be lower for utilities like Hoosier Energy, IMPA, and Wabash Valley due to the credibility of their planning processes.

None of the utilities articulated the changes that they may be considering to enhance their future load forecasts, including the potential long-term effects of distributed energy resources and new technologies, the databases, the consideration of DSM on a par with other resources, improvements to the construction of scenarios and sensitivities, the integration of probabilistic analysis into the IRPs, and providing IRPs that are consistent with the proposed IRP rule revisions.

## 6. List of Acronyms

|                 |   |
|-----------------|---|
| AMI             | Advanced Metering Infrastructure  |
| ASR             | Average System Rates  |
| Btu             | British Thermal Unit  |
| C&I             | Commercial and Industrial   |
| CO <sub>2</sub> | Carbon Dioxide  |
| DER             | Distributed Energy Resources  |
| DERMS           | Distributed Energy Management System  |
| DLC             | Direct Load Control   |
| DSM             | Demand-Side Management  |
| EIA             | U.S. Energy Information Administration  |
| EE              | Energy Efficiency   |
| EM&V            | Evaluation, Measurement, and Verification   |
| G&T             | Generation and Transmission   |
| GDP             | Gross Domestic Product  |
| Gwh             | Gigawatt Hour   |
| HVAC            | Heating, Ventilation, and Air-conditioning  |
| IEA             | International Energy Agency   |
| IMPA            | Indiana Municipal Power Agency  |
| IRP             | Integrated Resource Planning  |
| kWh             | kilowatt hour   |
| LCOE            | Levelized Cost of Energy  |
| MISO            | Midcontinent ISO Regional Transmission Organization / Independent System Operator |
| MW              | Megawatt  |
| O&M             | Operations and Maintenance  |
| OECD            | Organization for Economic Co-operation and Development                            |
| PJM             | PJM LLC Regional Transmission Organization / Independent System Operator          |
| RPS             | Renewable Portfolio Standard  |
| PRS             | Power Requirements Study (requirement of the RUS)                                 |
| RUS             | Rural Utilities Services (U.S. Department of Agriculture)                         |