

**Final
DIRECTOR'S REPORT
for the
2017 Integrated Resource Plans**

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IRPs Submitted by

Hoosier Energy Rural Electric Cooperative (HE)

https://www.in.gov/iurc/files/Hoosier%20Energy_2017%20irp_public%20version_030118.pdf

Indiana Municipal Power Agency (IMPA)

<https://www.in.gov/iurc/files/2017%20IMPA%20IRP%20-%20REPORT.pdf>

Wabash Valley Power Association (WVPA)

<https://www.in.gov/iurc/files/WVPA%202017%20Integrated%20Resource%20Plan.pdf>

December 27, 2018

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2017 Integrated Resource Plans and Planning Processes for Hoosier Energy, Indiana Municipal Power Agency, and Wabash Valley Power Association

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EXECUTIVE SUMMARY 2017 INTEGRATED RESOURCE PLANS

Hoosier Energy, Indiana Municipal Power Agency, Wabash Valley Power Association

PURPOSE OF IRPS

By statute¹ and rule,² integrated resource planning requires each utility that owns generating facilities to prepare an Integrated Resource Plan (IRP) and make continuing improvements to its planning as part of its obligation to ensure reliable and economical power supply to the citizens of Indiana. A primary goal is a well-reasoned, transparent, and comprehensive IRP that will ultimately benefit customers, the utility, and the utility's investors. At the outset, it is important to emphasize that these are the utilities' plans. The Commission, by statute³, does not take a position on the relative efficacies of any of the utilities' "Preferred Plans."

An IRP is a systematic approach to better understand the complexities of an uncertain future, so utilities can maintain maximum flexibility to address resource requirements. Because absolutely accurate resource planning 20 years into the future is impossible, the objective of an IRP is to bolster credibility in a utility's efforts to capture a broad range of possible risks.⁴ By identifying uncertainties and their associated risks, utilities will be better able to make timely adjustments to their resource portfolio to maintain reliable service at the lowest reasonable cost to customers.

Every utility and stakeholder anticipates substantial changes in the state's resource mix due to several factors,⁵ and, increasingly, Indiana's electric utilities are using IRPs as a foundation for their business plans. Since Indiana is part of a vast interconnected power system, Indiana is affected by the enormity of changes throughout the region and nation. Inherently, IRPs are very technical and complex in their use of mathematical modeling that integrates statistics, engineering, and economics to formulate a wide range of possible narratives about plausible futures. The utilities should utilize IRPs to explore the possible implications of alternative resource decisions.

These resource portfolios should not be regarded as being the definitive plan that a utility commits to undertake. Rather, it should be regarded as a road map based on the best information and judgment at the time the analysis is undertaken. The illustrative plan should provide off-ramps to give utilities maximum optionality to adjust to inevitable changing conditions (e.g., fuel prices, environmental regulations, public

¹ Indiana Code § 8-1-8.5-3.

² 170 IAC 4-7; see also "Draft Proposed Rule from IURC RM #11-07 dated 10/04/12", located at: <http://www.in.gov/iurc/2843.htm> ("Draft Proposed Rule")

³ Indiana Code § 8-1-1-5

⁴ In addition to forecasting changes in customer use of electricity (load forecasting), IRPs must address uncertainties pertaining to the fuel markets, the future cost of resources and technological improvements in resources, changes in public policy, and the increasing ability to transmit energy over vast distances to access economical and reliable resources due to the operations of the Midcontinent Independent System Operator (MISO) and PJM Interconnection, LLC (PJM).

⁵ The primary driver of the change in resource mix is due to relatively low cost natural gas and long-term projections for the cost of natural gas to be lower than coal due to fracking and improved technologies. As a result, coal-fired generating units are not as fully dispatched (or run as often) by MISO or PJM. The aging of Indiana's coal fleet, the dramatic decline in the cost of renewable resources, the increasing cost-effectiveness of energy efficiency as a resource, and environmental policies over the last several decades that reduced emissions from coal-fired plants are also drivers of change.

policy, technological changes that change the cost effectiveness of various resources, customer needs, etc.) and make appropriate and timely mid-course corrections to change their resource portfolios.

INTRODUCTION AND BACKGROUND

Hoosier Energy, WVPA, and IMPA have submitted well-reasoned IRPs. From the Director's perspective, these IRPs demonstrate continued improvement in their analysis, utilization of state-of-the-art long-term resource planning tools, and expertise. It is commendable that all of the utilities made strides to integrate probabilistic or stochastic analysis into their IRPs and recognize that traditional scenario analysis and probabilistic analysis are complimentary rather than being substitutes. These three utilities also have included wholesale market information into their IRPs which contributes to the credibility of their IRPs.

The relatively low price of natural gas, renewable resources, Demand Side Management (DSM), and wholesale market prices, are changing historical concepts of appropriate diversification of resources. As all utilities in Indiana and throughout the nation continually re-evaluate their resources, the uncertainties and attendant risks increase. With the increased potential for adverse ramifications from increased uncertainty and risk, and consistent with the IRP Rule requiring continual improvements, the Director urges all utilities to continually assess potential improvements to their planning processes.

Consistent with the law and the Draft Proposed Rule, these three utilities have recognized areas that could be improved in subsequent IRPs. To varying extents, these three utilities recognized the need for improvements in their load forecasting, data, and risk analysis. The members of the three utilities are in various stages of installing Advanced Metering Infrastructure (AMI), which provides the opportunity to develop customer specific data to facilitate enhanced load forecasting, DSM, and Distributed Energy Resources (DER) analysis. The Director recognizes that all utilities are struggling with how to use this type of data and that these utilities' organizational structures limit their abilities to coordinate with their members the collection of even the most basic data, such as billing data, for end-use customers and customer surveys for all types of customers. However, load forecasting, DSM, and long-term resource planning is hampered without greater coordination in data and analysis. As DER and other innovative technologies achieve greater penetration, the lack of coordinated data may frustrate attempts to understand the ramifications for their respective systems.

Three Primary Areas of Focus

The Director recognizes the complexity of the several elements of IRPs and has selected the following three to highlight: load forecasting, DSM, and risk management. In the three focus areas, the Director recognizes there is no right or wrong way to conduct the analysis. Different approaches have been useful to advance the understanding of the various elements of IRPs, but it is premature to standardize those elements.

Hoosier Energy's 2017 Integrated Resource Plan and Planning Process

Load Forecasting

Hoosier Energy compiles a 20-year (Hoosier Energy IRP, p. 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 energy forecasting 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. (Hoosier Energy IRP, 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. ((Hoosier Energy IRP, p. 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.

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. ((Hoosier Energy IRP, pages 29-30).

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 ((Hoosier Energy IRP, p. 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. ((Hoosier Energy IRP, p. 20).

The following factors were considered to determine the range of changes in the variables driving the forecasts ((Hoosier Energy IRP, p. 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).

Director's Draft Report and Hoosier Energy Responses

In the Draft Report, the Director expressed a concern that the C&I forecast for each Member was based on a “judgmental approach.” Such judgmental approaches can be accurate in the near term but tend to be inaccurate in the long term because the people making the judgments have no concrete basis for long-term changes. The Director also questioned whether the range of C&I forecasts adequately represent the uncertainty inherent in the C&I sector.

Hoosier Energy noted in its reply that the commercial sector forecast is based on a trend/pattern analysis and a judgmental methodology broken down into existing and new customer base, examining both customer count and energy usage. Hoosier Energy believes that by breaking the commercial sector's forecast down into an existing customer and a new customer mix, they are able to examine details of historical patterns to see what has happened to the commercial group as a whole. Hoosier Energy stated that in discussing and obtaining knowledge from the Member systems on what they have seen happening in this group, as well as what would be expected to happen in this group, Hoosier Energy is able to “develop very realistic expectation in driving both existing and new consumer forecasts.” (Hoosier Energy Reply, p. 1) ⁶

Hoosier Energy is confident in the industrial sector forecast because the forecast is linked to real knowledge and plans of each individual industrial customer. Hoosier Energy gathers knowledge from the retail consumer, the Member system staff, the Hoosier Energy Key account staff, the Hoosier Energy Economic Development Group, and historical load experiences. Hoosier Energy argues this detailed customer specific methodology provides the capability to simulate short-term and long-term shifts in loads, whether it is load additions and/or load reductions/closures. For potential new loads, Hoosier Energy stresses the need for “dirt to be turning” and/or a contract be established before including such a

⁶ The North American Industry Classification System would allow Hoosier to segment the more significant customers or more energy intensive customers (e.g., grocery stores, restaurants, clinics, hospitals, schools, etc) into more homogenous groups. This information, in conjunction with customizing customer survey instruments to evaluate the most significant end-uses and billing data, can provide a wealth of information that can be used not only for forecasting but also for designing DSM programs, DER rates, retail rates, distribution / transmission / and resource system planning. To be clear, few utilities maintain their NAICS data base despite recognizing the value of the information

load in the forecast. Hoosier Energy emphasized for both the commercial and industrial forecast that completing the process every two years allowed them to understand if the forecasts are close to representing what is happening and make adjustments as needed.

While the processes outlined by Hoosier Energy have merit and may have accurately estimated industrial energy use and demand, these do not address the market fundamentals for each type of industry. Moreover, from the Director's experience, industrial customers often have a relatively short planning horizon because of an emphasis on short-term profitability. Anecdotally, other utilities have recognized that industrial customers are reticent to provide information that might be regarded as competitively sensitive. One of the concerns, then, is that Hoosier Energy may not be able to assess the penetration of customer-owned resources or the willingness of industrial customers to participate in demand response. Given the potential risks of losing (or gaining) an industrial customer, it seems appropriate to devote more analytical effort to forecasting industrial customers' energy use and demand.

The Director also stated in his Draft Report that it was unclear how well load forecast uncertainty was addressed even when Hoosier Energy used low- and high-load forecasts based on different economic assumptions. Also, four other forecasts were developed by Hoosier Energy using the base forecast with varying weather conditions represented by alternate parameters for heating degree days and cooling degree days.

Hoosier Energy responded that they create slight variations across scenarios for the commercial and industrial sector, and that these adjustments are customized to each Member system based upon the level of commercial and industrial loads on their systems. (Hoosier Energy Reply, p. 2)

Hoosier Energy also stated that it introduces into the scenario load forecast fluctuations for the addition and loss of a typical sized industrial load on each of the 18 Member systems, which in many ways could simulate the addition or loss of one large load and/or the addition or loss of several new unplanned loads. (Hoosier Energy Reply, p. 2)

The Director also raised a question about the particular load forecast used in the IRP's base case. 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. 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.

Hoosier Energy responded that it decided to use the Base-Upper Normal forecast as its base reference forecast in the IRP not as a response to weather, but because it was thought to be more representative of the expected system growth over the next 20 years.

The Director appreciates the additional detail provided by Hoosier Energy in its reply to the Director's Draft Report. However, this additional detail should have been included in the IRP discussion. The Director also understands that the use of judgment-based load forecasts can be quite accurate over the first few years of the forecast horizon, but the use of judgment means there is little basis on which to develop a 20-year load forecast. Any long-term load forecast is subject to extensive uncertainty, which

puts a premium on the need to address this uncertainty. Any ability to judge how well load forecast uncertainty was evaluated in the modeling depends on an accurate description of what was done and why.

Demand-Side Management

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 (p. 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.

Director's Draft Report and Hoosier Energy Responses

The Director noted it was difficult to tell whether demand-side and supply-side resources were optimized simultaneously in the IRP long-term resource planning model and without preselection of certain resources. It appeared a base level of demand-side resources was predetermined and included in the load forecast, but there was little discussion in the IRP as to how this was done and with what rationale. According to the IRP, additional DSM was evaluated using a LCOE analysis, but it was unclear if additional DSM resources was included as a selectable resource in the resource integration process. The Director noted additional DSM was not mentioned as a selectable resource in the resource integration and optimization portion of the IRP.

Hoosier Energy stated in its reply that they worked with PA Consulting to conduct an assessment of potential additional economic DSM measures, which was described on pages 88-91 of the IRP. Each potential DSM program was grouped into portfolios of related measures, and the collective potential of the portfolio to reduce the cost to serve load was projected. The LCOE of each portfolio was calculated, and those portfolios that were determined to be economic were then compared to the supply-side resources selected to determine if the inclusion of the DSM portfolios would lower the net present value (NPV) of the individual model runs. The cases that included the additional DSM programs did not

contain enough avoided energy or capacity to defer or avoid a new generic resource. (Hoosier Energy Reply, p. 7)

The Director also raised questions on the interrelationship between the load forecast and DSM. There is a one paragraph discussion of DSM in the load forecast section ((Hoosier Energy IRP, p.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 has 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.

In its reply, Hoosier Energy provided further discussion on how DSM impacts were integrated into the load forecast. Hoosier Energy stated:

In “pre-forecasting modeling,” historical DSM impacts are extracted from applicable variables, models are developed using these variables without DSM impacts. Member system forecasts without DSM impacts are then developed based on these models. DSM forecast values on a per Member basis are obtained from separate, stand-alone DSM models. Forecasted DSM impacts are then incorporated into each Member forecast through a “post-modeling” DSM adjustment, resulting in a forecast including DSM impacts. Hoosier’s forecast is then obtained through aggregation of all 18 Member system forecast results with DSM impacts included. (Hoosier Energy Reply, p.5)

The additional explanation provided by Hoosier Energy in the above response is helpful, but the Director is still left with a confused discussion by Hoosier Energy as to how DSM was accounted for in the load forecast and how incremental DSM was modeled. Future Hoosier Energy IRPs should include better discussions of how DSM was accounted for in the load forecast and how additional DSM is modeled in the resource optimization modeling.

The Director acknowledges the difficulty of accounting for the effects of DSM on the load forecast. There are a number of different ways to perform this task but which technique works best in a particular circumstance calls for considerable judgment. Hoosier Energy’s choice of methodology places emphasis on acquiring accurate estimates of DSM impacts because the accuracy of the load forecast depends on the accuracy of DSM impact estimates. The Director encourages Hoosier Energy to periodically review the performance of this adjustment technique, as it can result in the load forecast being consistently too high or too low. Additionally, the Director encourages Hoosier Energy to consider the potential benefits and costs of significant increases (and decreases) of DSM even if they are low probability events; the broader analysis may provide useful insights.

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 AURORA^{xmp} model in an iterative process for the long-term planning for the Midcontinent Independent System Operator (MISO) area. The AURORA^{xmp} modeling process yielded projected market prices for MISO Zone 6, where Hoosier Energy is located. PA then used these market prices to develop the projected dispatch and market revenues for each owned and contracted resource, 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 NPV 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 results for only 12 of the discrete scenarios were summarized at a very high level in Table 29 on page 86 of the Hoosier Energy IRP.

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. However, Hoosier Energy elected to provide additional information on the modeled scenarios by focusing on the individual parameters that PA Consulting determined had the greatest impact on the long-term economic viability of current resources.

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%.

The results for these supplemental scenarios were summarized at a high level in Table 30 on page 88.

Director's Draft Report and Hoosier Energy Responses

The more significant questions and concerns raised by the Director centered on the lack of discussion of the scenario modeling results and how these results were used to determine the preferred resource plan. More specifically, the Director noted that Hoosier Energy presented results for only 12 of the initial 36 scenarios. The Director also specifically noted the minimal discussion by Hoosier Energy in the IRP of the supplemental scenarios based on the 2017 PRS.

Hoosier Energy responded that it did not provide modeling results for any of the 12 cases that modeled a 20% market tolerance as it was decided that level of market exposure was excessive. In addition, the Increased Capital Expenditures and Higher Fixed Costs sensitivities (12 cases) were not included because they were run as upper-boundary sensitivities on the base market cases and not all results were available at the time of filing. (Hoosier Energy Reply, p. 8)

Hoosier Energy noted on page 77 of its IRP that “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 concurs with this statement, but the minimal discussion of the modeling results and how these results were interpreted by management to determine the preferred resource plan leaves open the question of how management employed the models and the results to make resource decisions. To provide greater insights, the Director has consistently urged Indiana utilities to develop highly consequential scenarios even if there is a low probability that these events will materialize.

The Director notes that Hoosier Energy's IRP consultant for resource integration, PA Consulting, used several models, with AURORA^{xmp} being one. The other models appear to be models that were developed by PA Consulting for their proprietary use. The PA Consulting proprietary models included, but might not be limited to, a stochastic dispatch optimization model and a portfolio optimization model. The descriptions of the models on pages 74-77 were helpful, but the Director would appreciate additional information and documentation in the future as to how these models work to better understand the entirety of the IRP modeling exercise and, more specifically, how these models interact with each other.

INDIANA MUNICIPAL POWER AGENCY's (IMPA) 2017 INTEGRATED RESOURCE PLAN AND PLANNING PROCESS

Load Forecasting

In 2017, IMPA's peak demand for its 61 member communities was 1,128 MW and the annual member energy requirements during 2017 were 6,098,477 MWh.

IMPA noted that macroeconomic variables are historically significant drivers of energy demand. Additionally, weather and calendar related variables have historically proven to be significant predictors of peak demand. IMPA also noted factors that are expected to have impacts in the future include policy changes, 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.

IMPA used linear regression for forecasting both energy and peak demand in IMPA's five load zones (Duke-Indiana, Duke-Ohio, Vectren, NIPSCO, and AEP). Each load zone included several IMPA members. Table 5 on page 5-31 of IMPA's IRP listed the primary drivers for the energy forecast as calendar impact (peak and off-peak days), weather effects (heating and cooling degree days), energy efficiency changes (energy intensity defined as Btu / \$ of real GDP), economic impact (Real Gross Domestic Product, household debt, and Indiana non-farm payrolls), and population changes (total households). IMPA said it considered using a dummy (or binary) variable for peak season (e.g., June-August).

As detailed on Table 9 on page 5-34 titled "Demand Forecast Variables," the primary drivers for the linear equation that IMPA developed to forecast peak demand were expected daily load (MWh), temperature, wind speed, barometric pressure, and intra-day temperature deviations. IMPA said it considered a dummy variable to isolate peak day conditions within the month. IMPA used data from the Energy Information Administration (EIA) for energy intensity to capture the impacts of energy efficiency on demand for electricity. For those energy forecasts that used energy intensity as measured by total Btu / \$ of real GDP, energy intensity was estimated to decline at a roughly 2% year over year rate as set forth by the International Energy Agency's (IEA) 2016 "Energy Efficiency Market Report: 2016" for countries in the Organization for Economic Cooperative Development (OECD). IMPA relied on the St. Louis Federal Reserve "FRED" database for all other economic variables. IMPA noted the challenge of finding independent and potentially unbiased forecasts of explanatory variables:

Independent / unbiased forecasts for variables such as payrolls and even state specific economic growth are at best, stale and at worst difficult to find. As a result, IMPA has relied on macroeconomic variables that have a more national scope or can otherwise be modeled using variables with widely available forecasts. (IMPA IRP, p. 5-35).

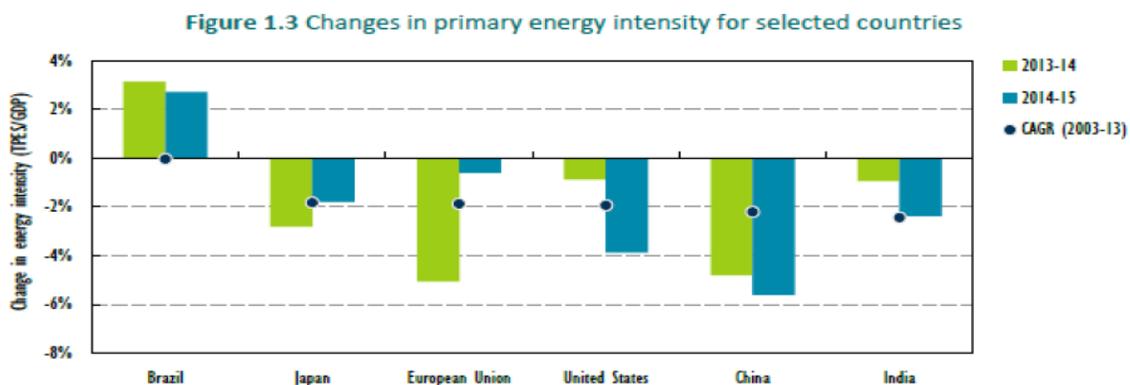
Director's Draft Report and IMPA Responses

Given the historical growth and the underlying fundamentals, IMPA's load forecast appears to be reasonable. IMPA's narrative describing the base case, a high economic growth case, and a low economic case provides a credible range of load forecast uncertainty. However, IMPA might benefit from a greater risk band to assess low probability but highly consequential events such as the loss or gain of a member.

The range of uncertainty and attendant risks in the load forecast (not just the stochastic analysis of resource plans) might have also been more revelatory if IMPA had given more consideration to emerging trends, potential policy changes, 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. However, if any consideration was given to these factors, the narrative did not discuss how these factors were specified, quantified, and integrated into the linear equations, or how IMPA intends to improve the databases to support the integration of these variables in the future.

In a question to IMPA, the Director asked if IMPA considered that relatively optimistic projections of real GDP might cause an upward bias for the load forecast. The Director also expressed concern about IMPA using the IEA’s OECD-wide projection of changes in energy intensity. Since the energy intensity (prices and personal income) are probably very different in many OECD nations and may be less representative of a specific state, it may not be a good data source. IMPA’s response was:

IMPA’s assumed growth rates for real GDP growth in 2017, 2018, and 2019 were 2.16%, 2.1%, and 1.8%. 2017 GDP growth was approximately 2.5%. IMPA tried to account for high forecasts in the GDP survey data by not using abnormally high or low estimates for growth where there were large deviations from consensus. As for the energy intensity variable, IMPA notes the concern that OECD’s estimates for global energy intensity may be too optimistic; however, IMPA did use a rate that was consistent with the noted improvements in energy intensity for the United States, shown below. This was not clearly stated on our part however. IMPA appreciates the Director’s concerns and agrees with the Director that some macroeconomic data may not be suitable for use in a much smaller geographic footprint. IMPA will endeavor to find data more relevant to the Indiana footprint. (IMPA Reply, p. 5)



As IMPA generally observed on page 5-44, residential customers are regarded as being largely homogenous. However, the differences are likely to be increasingly important to the credibility of forecasts, the development of well-reasoned DSM, and projecting the penetration of new technologies such as roof-top solar and electric vehicles. Commercial and industrial (C&I) customers are much more heterogeneous. Because of the differences in operations, end-uses, and building types, C&I customers also have varying abilities to improve efficiencies of operations and equipment, as well as install their own generating resources. Increasingly, these differences will affect the load forecasts and resource planning. IMPA noted in reply comments

IMPA communities have never provided IMPA any detailed demographic data. It is not known if the member cities have attempted any surveys, however given their somewhat

limited resources it is unlikely [except] for in the largest communities. The use of IMPA survey data has been contemplated but ultimately dismissed given the volume of surveys that would be required to achieve a valid sample from each of IMPA's diverse communities.(IMPA Response to Question 3.3.1.6)

The Director understands the demarcation between IMPA's wholesale sales to its members and the members' retail sales to the end-use customers. As such, the member's designate how rate classes are defined and control much of the data necessary for IMPA to conduct credible load forecasting, DSM analysis, and resource planning. Given the potentially significant ramifications of future resource decisions, the Director hopes that IMPA's members will work with IMPA to enhance the databases that may enable IMPA to incorporate more end-use data into its load forecasting and other analyses. IMPA might also consider obtaining data from utilities that have better load, appliance, and demographic data to supplement IMPA's data sources.⁷ The Director recognizes the difficulty in finding appropriate data sources is not unique to IMPA.

...Many IMPA members do not have AMR, let alone fully implemented AMI systems. However, a few of the larger communities do have AMI systems. To the extent data can be shared by those members with AMI, IMPA will attempt to use this information in the future. (IMPA's Reply to Question 3.3.1.9)

Data quality and quantity will be improved as AMI data becomes more prevalent. This should be especially valuable if combined with the following: integration of sub-metered data for major end-uses/appliances, conducting well-designed surveys to obtain demographic information, obtain quality data on the age, condition, loading of major appliances/end-uses, as well as information about the housing stock and business structures. In this regard, IMPA might consider working with other Indiana utilities, universities, National Laboratories/Department of Energy (DOE), and others to improve the databases over time, especially as the risks of uncertainty result in greater ramifications. As IMPA's members develop better data, IMPA's reliance on information from outside the IMPA system should diminish in importance. The Director recognizes that utilities in general are struggling with how to use data collected with smart meters but is hopeful that there will be steady progress on how to cost effectively use this type of information in a range of utility operations and planning processes. The Director also understands that tailoring a database that is more characteristic of an individual utility is costly and time consuming.

The Director believes that IMPA's forecast of the five individual zones is appropriate. However, it is not clear why some zones include dummy variables and others do not. The Director understands that the dummy variables may improve the R² statistic but the use of dummy variables may obscure differences that should be explicitly integrated into the forecast model. In response to the Director's questions in the Draft Director's Report, IMPA responded:

The dummy variable was primarily used to enhance fit for energy between months and signify peak seasons (i.e. winter and summer). December through February were

⁷ The North American Industry Classification System would allow IMPA to segment the more significant customers or more energy intensive customers (e.g., grocery stores, restaurants, clinics, hospitals, schools, etc) into more homogenous groups. This information, in conjunction with customizing customer survey instruments to evaluate the most significant end-uses and billing data, can provide a wealth of information that can be used not only for forecasting but also for designing DSM programs, DER rates, retail rates, distribution / transmission / and resource system planning. To be clear, few utilities maintain their NAICS data base despite recognizing the value of the information

assigned a 1 as well as June through August, while remaining months were assigned a zero. This helped both R² and the standard error of the estimation. (IMPA's Reply to Question 3.3.1.1)

On page 31, it appears that IMPA incorporated the dummy variables for Peak and Off-Peak Days and also for winter and summer peak seasons. It isn't obvious that a dummy variable is a useful indicator for both peak days and peak seasons within the same model. If dummy variables are used in subsequent IRPs, the Director respectfully requests a more detailed rationale for their use.

In addition to working with its members to get enhanced data, IMPA's response to the Director's question 3.3.1.14 highlighted one area that IMPA is focusing on:

IMPA feels that from both a planning and commercial standpoint, forecasting peak demand is the biggest challenge. One key variable that feeds the peak demand forecast is the monthly energy forecast. More specifically, a daily energy consumption multiplier is applied to the monthly load forecast to forecast the peak demand. In other words, we are concerned with how much of the monthly energy consumption for the month occurs on the peak day. Historically, this has been between 3.8% and 4.2%, depending on load zone. It's recently been discovered this value is declining so we continue to revise estimates of that value to enhance understanding of how the system behaves during peak conditions. Since the revision of this estimate, we have been tracking weather adjusted peaks fairly well in 2018.

In summary, given the data limitations, IMPA's load forecast was reasonable. However, the Director believes that IMPA would be well-served by a more expansive set of load forecasts to provide better bookends for risks faced by IMPA. The Director also appreciates IMPA's load forecasting graphics. They were very well done.

Demand-Side Management

IMPA said DSM was an important element in maintaining a diverse set of energy resource options. Since the Energizing Indiana program ended in 2013, IMPA has spent about \$425,000 on energy efficiency programs. These programs have resulted in 2 MW and 14,850 MWh of savings.

IMPA states that they offer a variety of DSM programs coordinated by IMPA as well as those implemented by its members (IMPA IRP, p. 4-25). The IRP also says IMPA's members have implemented a variety of programs and projects tailored to their individual systems to reduce peak demand and encourage efficient energy utilization. Examples of these programs include 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 street lighting replacement with more efficient lamps (IMPA IRP, p. 4-29). When discussing potential future resource options, IMPA notes that its energy efficiency program has been the primary vehicle used to provide energy efficiency options to IMPA members' retail customers. The program is a prescriptive rebate system providing incentives for the installation of dozens of measures. Incentives are available for both residential and C&I customers. Both measures and incentive amounts are reviewed periodically to determine additions, deletions, or modifications to incentive payments. (IMPA IRP, p. 6-47)

Director's Draft Report and IMPA Responses

Although IMPA and its member communities seem to have a reasonable array of DSM, these are only existing programs with no discussion provided as to how new programs are developed or existing programs are refined. The total reliance on existing programs suggests that IMPA and its member systems did not consider new technologies and new methods that might improve the cost-effectiveness of some DSM programs. It's clear from the IRP and IMPA's responses to Question 3.4.1.1 that the Aurora^{XMP} model was not allowed to select new energy efficiency. Moreover, the IRP was not clear that either new energy efficiency or demand response resources were modeled. As a result, the Director concluded that no new energy efficiency or demand response were considered and, therefore, were not optimized with other resources.

IMPA makes no mention of basing its DSM decisions on a Market Potential Study, so it is difficult to know how IMPA and its members objectively and quantitatively assess the future value of DSM. The Director urges IMPA, for future IRPs, to develop an objective Market Potential Study based on appropriate data to enable IMPA to assess the value of energy efficiency and demand response.

Even if IMPA does not plan to file for new resources, IMPA and its members may be forgoing savings opportunities. Given the recent and increased importance placed on DSM by MISO (e.g., the *Resource Availability and Need – Issues Statement and Whitepaper*, March 30, 2018) and PJM, this seems to be a propitious time for IMPA and other utilities to undertake a reassessment of their DSM programs. Evaluation, measurement, and verification of DSM takes a few years to develop confidence in the effectiveness of specific DSM programs.

Future IRPs should consider customer-owned resources (e.g., DERs such as roof top solar installations, community solar, combined heat and power, and micro grids). The Director understands that customer-owned resources are not a major factor now but, based on national trends, the increased penetration of DERs is likely. To this end, the Director urges IMPA and its members to develop timely information on these resources.

In summary, this is clearly one area where the structure of IMPA imposes limitations on information that would be beneficial to IMPA's consideration of all viable resources in making future resource decisions. As with IMPA's load forecasting, IMPA does not seem to have either the quality of information or sufficient data from its members to credibly model the potential benefits and costs of DSM. IMPA stated:

Hourly loads are shown in Appendix A and typical annual, monthly, weekly, and daily load shapes for IMPA as a whole are shown in Appendix B. As a wholesale supplier, IMPA does not have the necessary retail load information to draw conclusions concerning disaggregation of load shapes by customer class or appliance. (IMPA IRP, p. 4-20).

IMPA's IRP and responses to questions confirms that IMPA has limited access to information about the end-use customers' usage of electricity. The Director recognizes the costs and effort required to populate the state-of-the-art planning tools that IMPA utilizes, but it is essential for well-reasoned long-term resource planning to consider all viable resources on as comparable a basis as possible.

Resource Optimization and Risk Analysis

IMPA developed three scenarios (Base Case, Green Case, and a High Growth Case). These scenarios were optimized using Aurora^{XMP} for the 20 year generation expansion plan. Once the optimal portfolio was selected, IMPA subjected the portfolios to stochastic (probabilistic) analysis using the Aurora^{XMP} resource planning model.

Base Case: The Base Case is regarded as the least cost solution. IMPA anticipates continued low market prices and filling capacity needs with bi-lateral capacity transactions. After 2026, IMPA assumes a carbon tax will be instituted and result in the retirement of the Whitewater Valley Station (100 MW). This will necessitate replacement capacity with less carbon intensive sources of generation such as combined cycle units in 2026 (200 MW) and 2034 (264 MW)) and wind (100 MW). (IMPA IRP, p. 15-146).

The Green Case: This case considered a \$40/ton CO₂ tax in 2026 and a federal Renewable Portfolio Standard (RPS) of 20% of energy sales by 2030. This case resulted in significant coal retirements and additions of renewables in order to meet and maintain the RPS mandate. Coal capacity is largely replaced with natural gas combined cycles. IMPA noted:

Interestingly, as the Green portfolio is optimized for a carbon limited world, impacts from uncertainty in CO₂ price are less impactful than in the Base Case. (IMPA IRP, p. 15-151)

High Growth Case: The High Growth Case assumes robust economic growth throughout the study timeframe, with growth spurring demand for most commodities across the board, including electricity consumption. In this case, there are no assumptions made regarding CO₂ policy, however the stochastic modeling of CO₂ allowed for a handful of iterations to illustrate a modest carbon tax. Unsurprisingly, there were no IMPA retirements and the only capacity additions were natural gas combustion turbines (CTs) to meet higher expected peak demand.

Action Plan

IMPA's action plan includes: (1) securing bilateral capacity in the five to seven year term; (2) secure market energy needs for same time frame; (3) continue monitoring the federal legislative process in order to gain more clarity on the future of CO₂ legislation; (4) continue IMPA Solar Park Program; (5) investigate replacement of 50 MW Crystal Lake wind contract; (6) continue with IMPA Energy Efficiency Program (emphasis added); and (7) continue to develop IMPA's modeling capabilities in the areas of:

- o Zonal Optimization/Market Price Development;
- o Portfolio Optimization;
- o Stochastics and Risk Identification/Mitigation;
- o Nodal analysis.

Director's Draft Report and IMPA Responses

IMPA currently has a diverse resource mix that has helped them navigate risk in prior years. IMPA's Short Term Action Plan that emphasized reliance on wholesale markets seems well-reasoned. Arguably, consideration of longer-term risk was too limited. As with IMPA's previous IRP, IMPA provided an excellent discussion of how stochastic (probabilistic) analysis would enhance understanding of future uncertainties, the attendant risks, and the potential ramifications. IMPA also evaluated a number of risk and uncertainty metrics and this information was presented with very good graphics. However, there was

minimal discussion of how the detailed information was interpreted and used by IMPA in its evaluation of various resource portfolios. These concerns make it difficult to understand how IMPA was able to designate a preferred plan. For example, a common theme through all the cases is the effect on IMPA's rates. This is an appropriate metric but it seems to be inconsistent with the constrained risk analysis in the different scenarios and portfolios.

For the longer-term assessment of uncertainties and risk, the Director urges IMPA to give additional scrutiny to the load forecast methods, a more robust consideration of energy efficiency/demand response, and a broader analysis of the various risk factors that will drive future resource planning.

First, the load forecast utilized only three scenarios (high, low, and most expected) and did not give consideration to highly consequential events that had low probabilities (e.g., such as losing or adding members or major loads, or the potential for increased customer-owned resources).

Second, based on IMPA's response to Question 3.4.1.1, the operative phrase was *generation expansion plan* because IMPA's IRP modeling and optimization process did not consider future energy efficiency. In response to questions, IMPA stated, "Demand response was not alone in terms of resources that were not selected by the model when creating expansion plans." This comment suggests that demand response may have been allowed to be chosen by the Aurora^{XMP} model, but there was no discussion in IMPA's IRP or responses to the Director's questions to provide any clarity as to how demand response was analyzed.

Third, while IMPA recognizes stochastic analysis provides an analysis of risk that is complimentary to scenario analysis, it is not clear how the information derived from the stochastic analysis was used in the IRP. There were also other scenarios that could have been considered to enhance the value of stochastic analysis. An additional two or three well-constructed scenarios that considered, for example, possible technological changes, would have provided more expansive stochastic analysis which would have increased the robustness of the IMPA's risk analysis.

Despite IMPA saying in its reply comments that Aurora^{XMP} requires the use of data in real dollars and its outputs are in nominal dollars, it is not always clear whether real (inflation adjusted) dollars were used in the risk analysis.

IMPA continues to give appropriate consideration to the opportunities, risks, and uncertainties of the MISO and PJM facilitated markets.

WABASH VALLEY POWER ASSOCIATION's (WVPA) 2017 INTEGRATED RESOURCE PLAN AND PLANNING PROCESS

Load Forecasting

WVPA changed its forecasting process and methodology since its previous IRP. WVPA now uses ITRON's MetrixND®. WVPA also addressed persistent over-forecasting of load requirements for its 23 Members. According to WVPA, previous forecasts of individual Members, by class of customers, were aggregated (i.e., summing each Member's forecast) and WVPA relied on its Member's forecast of C&I load. In particular, reliance on Member estimates of projected use by C&I customers proved to be overly optimistic.⁸

The forecast for this IRP seems to be, in essence, a single econometric equation to estimate total usage at the wholesale level for each Member. The linear equation includes end-use intensity, county-level economic data, and Member area specific weather data (WVPA IRP, p. 37). WVPA derives a Member's total retail sales by applying distribution loss factors to the wholesale sales forecast for each Member. WVPA's forecast method now also places primary focus on the residential energy use for each Member system because of higher confidence in the predictability. Each Member's monthly residential load forecast is based on monthly customer and average use forecasts where the average use model is estimated using an end use model specification. Simple trend models are used to estimate street lighting sales. The monthly C&I sales forecast is developed by subtracting the residential and other sales forecast for each Member from the forecast of total retail sales by Member. WVPA stated it does not attempt to model the load of these commercial customers using econometric techniques because historical monthly C&I sales are either not available or include data discrepancies. WVPA also commented that they have separate monthly energy and coincident peak demand models (WVPA IRP, p. 37).

WVPA separately forecasts Pass-Through Loads. These are large customers with non-conforming load. The Pass-Through Load customers have the ability to customize their supply portfolio based on their respective risk tolerances. As a result, each Pass-Through customer is forecasted separately utilizing forecasts provided by each customer combined with internal insights and discussions. Pass-Through Load is not included in the total energy or peak load managed by WVPA. However, the load for these customers are included in WVPA's total planning load because WVPA states that it is ultimately responsible for meeting the minimum reliability requirements.

WVPA stated they constructed two alternative load forecasts (high and low economic growth) to give effect to risk and uncertainty. The high and low forecasts were developed using higher (or lower) Gross Regional Product, population, households, and household income. ((WVPA IRP, p. 54).

⁸ *As a wholesale supplier, Wabash Valley's primary focus is the total forecast by Member. Because C&I Members are less homogenous than residential Members, the C&I class is more difficult to forecast accurately. This methodology is a revamp of our previous methodology. In the past, we relied more on information provided by Member cooperative staff. In some cases, we found this information to be overly optimistic because the Member was attempting to be conservative in order to plan for potential load growth. Wabash Valley plans to retain this methodology for at least a few load forecast cycles. We will consider a change to this methodology if it proves to be inaccurate.*

WVPA's Response to Director's question 4.1.3.2

Director's Draft Report and WVPA Responses

The Director appreciates that WVPA's organizational structure necessitates reliance on its Member Cooperatives to provide information for forecasting the demand and energy use of their ultimate customers, as well as customer participation in DSM programs and customer-owned resources. Some of the comments detailed below illustrate the conundrum of WVPA's responsibility for securing sufficient resources to meet future needs of the end-use customers, having powerful analytical tools and expertise, while being constrained by data.

The Director has three comments about the forecast methodology. First, it is difficult to envision how a single equation to forecast total wholesale sales by Member can provide credible projections of WVPA's Members' long-term usage, which largely hinges on the confidence in the residential use projections.⁹ WVPA stated:

We derive monthly C&I sales forecast by subtracting residential, and other sales from total Member retails sales; historical monthly C&I sales were either not available or included data discrepancies, making it difficult to directly estimate C&I forecast models (p. 37).

Under this approach, the C&I forecast for each Member is essentially a remainder after the residential and other sales are subtracted from the total retail sales forecast for each Member. WVPA states it checks the reasonableness of the C&I forecast by comparing whether it is consistent with other assumptions in the model. One assumes these other assumptions largely involve generalized economic growth and efficiency trends but does not consider independent forecasts of specific industries (e.g., economic trends for specific industries, the effects of tariffs or inflation on the specific industries). Under this methodology any errors included in the total retail sales forecast for each Member and the residential sales Member forecast will, by necessity, be reflected in the C&I forecast.

Second, the Director appreciates that this new methodology is less dependent on the judgment of each Member in developing the C&I forecast. The Director also appreciates WVPA needs time to evaluate the methodology. However, the Director urges WVPA to continually assess alternative methods to more credibly forecast its customers' requirements, particularly C&I customers' requirements. While increasingly sophisticated models are more data- and analytically-intensive, WVPA should weigh these costs and difficulties against potentially enhanced credibility.

Of course, changes in forecasting methodology would be evolutionary and require the development of consistent and reliable load data and supporting information (e.g., major appliances/end-uses, demographic data) from its Members. It is difficult to understand why WVPA cannot use the aggregated billing information for each Member's C&I customers. Since each Member collects the billing information, this should be the foundation for forecasting the aggregated C&I load. If WVPA wanted to delineate industrial from commercial customers, regardless of how each Member classifies industrial and commercial

⁹ According to WVPA, the residential sales forecast was derived as the product of customer and average use forecasts. Customer forecasts models are simple regression models that related to monthly customers to number of households in the counties serviced by the Member. Residential average use forecast is derived from a monthly Statistically Adjusted End-Use (SAE) model. The SAE model entails estimating a linear equation model that relates monthly customer average use to customer heating requirements (XHeat), cooling requirements (XCool), and other end-use requirements (XOther). The constructed model variables incorporate household income, household size, weather conditions, and end-use intensities. Models also include variables and binaries for large residuals that cannot be explained with available data. (p.45).

customers, WVPA could ask for the data based on WVPA's judgment of what level of usage constitutes industrial customers.¹⁰

The Director appreciates that WVPA cannot undertake this change unilaterally without the Members' approval and participation. This data concern is, therefore, a common theme in the Director's Report, which affects the load forecast, DSM, the relationship between load forecasting and DSM, and risk analysis.

Third, the Director is concerned about the potential ramifications of Pass-Through or non-conforming loads for WVPA and its Members. While the Director understands WVPA statement that these Pass-Through Loads are not included in the total energy or peak load managed by WVPA, these customers are included in WVPA's total planning load. As WVPA confirms, WVPA is ultimately responsible for meeting the minimum reliability requirements for both the non-conforming load and its traditional load requirements.

Fourth, the Director is somewhat concerned about WVPA's use of dummy variables. While dummy variables have their place, they can often be over-used as short cuts rather than gaining a better understanding of the cause of anomalous data. To be clear, it is unrealistic and not cost-effective to track down all anomalies. However, for future IRPs, the Director would appreciate WVPA's rationale for specific anomalies that result in the use of dummy variables. As WVPA stated, having better data would likely reduce the reliance on dummy variables (e.g., binaries).

In summary, future IRPs should: (1) provide formulas for the load forecast and how the data was injected into the equation; (2) provide discussion of future enhancements to the forecasting models and data bases; (3) provide a more detailed discussion of the Pass-Through customers relationship with WVPA and the potential ramifications to WVPA's Members if the contractual arrangements prove to be insufficient; and (4) provide more in-depth information of the rationale for dummy variables and the alternatives that were considered. Over time, the integration of AMI data to construct load shapes, continued improvements to the customer surveys, including for C&I customers, would be beneficial. The increasing amount of AMI data, combined with customer survey data, is useful for providing more explanatory information which adds to the credibility to load forecasting efforts.

Demand-Side Management

The energy efficiency programs were established in 2008 (WVPA IRP, p. 27). WVPA's demand response programs were established in 1981 with Direct Load Control programs. Prior to 1986, demand response programs were implemented by individual Members to reduce their maximum demand that were not necessarily coincident with the WVPA system peak demand. (WVPA IRP, p. 23). After 1986, WVPA implemented centralized control of demand response to reduce the WVPA system coincident peak demand. WVPA stated that it works with its Member Cooperatives to continue their energy efficiency and demand response programs.

¹⁰ The North American Industry Classification System would allow WVPA to segment the more significant customers or more energy intensive customers (e.g., grocery stores, restaurants, clinics, hospitals, schools, etc.) into more homogenous groups. This information, in conjunction with customizing customer survey instruments to evaluate the most significant end-uses and billing data, can provide a wealth of information that can be used not only for forecasting but also for designing DSM programs, DER rates, retail rates, distribution / transmission / and resource system planning. To be clear, few utilities maintain their NAICS data base despite recognizing the value of the information

WVPA's energy efficiency objective is to deliver cost-effective energy savings and a high level of Member satisfaction (WVPA IRP, p. 27). To this end, WVPA states that energy efficiency programs are evaluated for their benefit to WVPA and its Members. Programs implemented during 2012–2017 will continue (WVPA IRP, p. 6). According to WVPA, the Energy Efficiency Committee is responsible for the energy efficiency planning process. The Committee develops programs and evaluation, measurement, and verification protocols to assess the technical and economic viability of energy efficiency programs, which are validated and monitored by a consultant. The consultant also works with WVPA to assure that incentives paid which are proportionate to achieved savings. (WVPA IRP, p. 66). WVPA stated:

For [energy efficiency], we obtained high-level program cost estimates from a condensed study of achievable efficiency potential. (WVPA IRP, p. 64)

WVPA established the Demand Response Committee, comprised of WVPA staff and representatives of Member systems, to develop programs that reduce peak demand and contribute to resource adequacy.

The Demand Response Committee is responsible for the continuing demand response planning process. The screening process consists of the following steps:

- **Identifying DR measures and technologies**
WVPA uses several sources of information to identify potential demand response technologies including its Members' knowledge and experience.
- **Determining if measures are consistent with overall goals**
The primary objective is to reduce wholesale power cost to the Association.
- **Determining if there is adequate market potential**
Eliminates the measures that would not prove successful because of an economic or technical inability to utilize the technology. WVPA does not use standard tools for determining market potential but is investigating the options.
- **Conducting economic evaluation**
WVPA conducts a 5 year forward look at the wholesale market to conduct overall economic evaluation process.
- **Securing approval from executive level and Board of Directors**
- **Implementing Programs**

The following bundles were included in WVPA's resource optimization using the PLEXOS model. (WVPA IRP, p. 64).

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

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

Director’s Draft Report and WVPA Responses

From the Director’s perspective, the DSM discussion was not cohesive and left much unstated as to how energy efficiency and demand response was analyzed. For example, it is difficult to assess the estimates of energy efficiency contained in the “condensed study of achievable efficiency potential” (WVPA IRP, p. 64) since WVPA did not provide the condensed study. Also, developing a market potential for energy efficiency and demand response is heavily dependent on detailed data, but as WVPA has mentioned, in other areas, obtaining consistent quality data from Members has proven to be difficult. This is a reiteration of a comment in the load forecasting section that the quality and credibility of WVPA’s load forecast is potentially compromised by the absence of sufficient high quality load and other data – including detailed information on the performance of different DSM measures. WVPA’s response to Question 4.1.2.1 said:

Wabash Valley said they may consider conducting a commercial saturation survey in the future, perhaps as companion to PowerShift program as a means of gaining more insight into their C&I customers’ end-use patterns and their interest in DER.

In response to the Director’s Question 4.3.1.4, WVPA confirmed that a maximum of 50 MW of energy efficiency was *hardwired* into the analysis across all three portfolios. As a result, the Director does not understand how energy efficiency can be co-optimized ¹¹ (pgs. 69, 74-79) since the model was not able to select all of the cost-effective DSM available over the planning horizon.

For the next IRP, the Director respectfully requests that WVPA explain how the four DSM bundles were constructed, optimized, and how WVPA plans to integrate more detailed information into its future DSM planning process. The additional discussion should also include WVPA’s EM&V which would help inform understanding of how the DSM bundles were created and optimized. For example, the inclusion of numerous energy efficiency measures in a single resource bundle may reduce the ability of capturing the potential differences in cost and load characteristics between measures within each bundle.

The Director would also ask WVPA, in its next IRP, to consider whether it is reasonable to use the same load shape for energy efficiency as WVPA’s overall load shape. While this might have been accurate

¹¹ “From 2018 to 2020, the base resource plan recommends that we purchase incremental capacity from the market. Past 2020, the base resource plan recommends that we add a total of 576 MW of baseload CC resources and 336 MW of peaking CT resources along with some incremental market capacity purchases in certain years. Additionally, the base resource plan proposes we add an additional 50 MW of EE. *Although our optimization model did not choose our DR programs during the 20-year plan horizon....*” (emphasis added)

historically and may still be true for the near term, it may not be an accurate assumption in future years. Even in the short term, such an assumption may be satisfactory for refrigerators and insulation but it might not be a good estimator for more efficient lighting or temperature sensitive equipment, such as heating and cooling. In the absence of detailed load shapes for different types of customers – even within a class of customers – it leaves the impression that all customers within a class are homogeneous, which may increasingly be an incorrect assumption. Also, as noted above, the use of a single load shape for each DSM bundle makes it difficult to capture the potential differences in cost and load characteristics between measures within each group.

WVPA’s interest in expanding their demand response programs is well timed. The uncertainties, risks, and potential ramifications of a major restructuring of the state’s, the region’s, and the nation’s resource mix gave rise to the MISO’s “Resource Availability and Need” (RAN) analysis. MISO said the changing resource mix requires greater focus on all resources year-around availability. Additional demand response, throughout the region, may be helpful in addressing likely reliability concerns. In response to Question 4.2.2.1 WVPA responded, “Wabash Valley is always looking to expand our program. Currently, 19 of our 23 Members participate in our programs, which includes 26,840 retail customers.” (WVPA Reply pg. 5).

Resource Optimization and Risk Analysis

WVPA has an overall risk management strategy for addressing operational and planning processes:

In 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...This risk structure utilizes a Risk Matrix to identify and prioritize risks, such as commodity price risk, power and fuel delivery risk, financial risk, environmental and regulatory risk, etc., and then implement strategies to mitigate their effect on our association. The risk structure monitors the resource plan on a quarterly basis by reviewing a dashboard with key indicators and stress cases. This ongoing review process allows Wabash Valley to make adjustments to our power portfolio to better match the inherent risks of providing power to our Members. (WVPA IRP, p. 5)

The general risk factors discussed above were incorporated into WVPA’s scenario and risk analysis for its IRP. WVPA 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. In addition, four alternate scenarios were created. They are High Economic Growth, Low Economic Growth, Carbon Emissions Regulation with Coal Retirement Option and Renewable Cost Improvements. Each scenario consists of adjusting model inputs for Member load, fuel prices, capacity prices and energy prices. WVPA executed the Plexos® LT Plan® and the Plexos® MT Schedule® models deterministically under these four alternate scenarios to find the optimal portfolio of future capacity and energy resources that minimizes WVPA’s variable and fixed costs under each scenario over the 20-year plan horizon.

The goal of Wabash Valley’s IRP is to identify a mix of new resources that, when considered with our existing portfolio, provides the best combination of expected costs and associated risks and uncertainties for Wabash Valley and our Members. To achieve that goal, we utilized the PLEXOS® model to evaluate each of these supply-side and demand-side resource options on an equivalent basis. Plexos® selects resources in order

to reduce the overall portfolio cost, regardless of whether the resource is on the supply or demand-side. Specifically, we ran the Plexos® LP long-term optimization model, also known as “LT Plan®,” and the Plexos® medium-term simulation model, also known as “MT Schedule®,” to find the optimal portfolio of future capacity and energy resources that minimizes the Company’s variable and fixed costs over the twenty-year plan horizon. (WVPA IRP, p. 68)

Then, each alternative expansion plan was tested against several combinations of stochastic variables to determine how each plan performed against an unknown future.

Director’s Draft Report and WVPA Responses

Since the current DSM programs were hardwired into the long-term plan, rather than allowing the model to optimize DSM simultaneously with other resources, the portfolios were not fully optimized. This, in turn, adversely affects the perception of credibility of WVPA’s long-term resource planning.

The Director is pleased that WVPA is using state-of-the-art planning tools like PLEXOS and using both scenarios and stochastic analysis to conduct risk and uncertainty analysis for the IRP. In the Director’s opinion, over the years, WVPA has constructed a reliable and reasonably cost-effective resource mix. However, with the changing dynamics of the electric power system, traditional methods and tools are no longer sufficient. The Director hopes the utilization of new tools and analytical methods will help WVPA maintain a diverse, reliable, and economic resource mix that serves its Membership well.

The Director appreciates WVPA’s efforts to use graphics to convey important information. However, on page 91, Chart 5-17, “Comparison of Alternate Expansion Plans”, would benefit from a narrative to discuss the elements of the graphic and what information is intended to convey. On pages 86 - 90, WVPA offers Tornado Charts for each of the five scenarios, but it isn’t clear how the information was integrated into the IRP analysis. For example, the analysis would have benefited from a more expansive narrative of how the risk factors in the Tornado Charts inform WVPA’s ability to meet the two objectives of minimizing the average rates and minimizing risks. Other graphics to depict a broader range of risk metrics, with accompanying narratives, and a brief discussion of the potential ramifications would have been helpful.

As previously stated and as WVPA acknowledged, a broader load forecast risk analysis might have been beneficial. The base, high, and low cases probably capture the most probable risks but do not provide WVPA with an opportunity to consider other reasonable scenarios and more extreme risk and highly consequential events such as adding or losing a Member. Especially over the longer-term, the loss of a large industrial load due to customer-owned resources may prove to be significant, even in WVPA’s service territory. It also seems possible that a high penetration of roof top solar may have a significant effect on WVPA’s long-term resource planning. While WVPA reasonably anticipates that Electric Vehicles (EVs) will not be a major factor for a few years, how would WVPA respond if EVs achieve a much higher-than-expected penetration?

The Director also expressed concern about “Pass-Through” loads (referred to as non-conforming loads). Based on the response from WVPA, these customers take on financial responsibilities for WVPA to arrange power purchases and ancillary services to customize the power supply contracts for each of these customers. That is, each Pass-Through customer selects services that satisfy their risk tolerances and WVPA tailors their contracts accordingly. However, it is still not clear how the risk is apportioned among WVPA, its Members, ultimate customers, and the non-conforming loads.

[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.(WVPA IRP, p. 42).

The Director acknowledges that despite WVPA's improved description of the treatment of Pass-Through Load customers there is much that is not clearly stated as to which entity undertakes what specific actions; essentially, who is responsible for what and when. This should be addressed in subsequent IRPs.

In summary, WVPA's IRP was credible and well written, especially for near-term resource planning. However, the longer-term resource planning is a concern. Among other concerns, the Director believes that DSM may be a more viable option than is portrayed in the IRP if the scenario and risk analysis was more in-depth. WVPA said they would consider a broader range of load forecasts and natural gas prices. The Director appreciates WVPA's willingness to consider this broader risk but encourages WVPA to apply broader risks to other primary drivers of the resource plan.

Summary of HE's IMPA's and WVPA's 2017 IRPs

Aside from the ongoing transformation of the resource mix in Indiana, the region, and nation, there are several common denominators among the three public power utilities. All three IRPs provided a reasonable and thoughtful analysis of potential resource requirements. All three IRPs would be enhanced by more detailed narratives. The IRPs were well written with excellent graphics. All three utilities were limited by their databases (e.g., Member load data, load data from customers participating in DSM, information about customer appliances/end-uses, and demographic information), which adversely affects their ability to conduct load forecasts, DSM analysis, projections of customer-owned resources, and, as a result, their long-term resource plans. All three have a good history of understanding the MISO and PJM wholesale markets and the opportunities for informing their planning decisions.