

**DRAFT REPORT
OF
THE INDIANA UTILITY REGULATORY
COMMISSION

RESEARCH, POLICY, AND PLANNING
DIVISION DIRECTOR
DR. BRADLEY K. BORUM

REGARDING 2015-2016 INTEGRATED
RESOURCE PLANS**

Date of the Report: May 20, 2016

Table of Contents

INTRODUCTION	1
DUKE ENERGY INDIANA’S 2015 INTEGRATED RESOURCE PLAN AND PLANNING PROCESS	4
Duke Energy Indiana	4
Risk Assessment	6
Constructing, Evaluating, and Integrating DSM Bundles	8
The Calculation and Use of Avoided Costs in the IRP	12
Weather Normalization	12
Derivation of Peak Demand Estimates	12
Changes in Load Forecasting Methodology	14
General Discussion of Duke Energy Indiana’s IRP	17
INDIANA - MICHIGAN’S 2015 INTEGRATED RESOURCE PLAN AND PLANNING PROCESS.....	19
Including Energy Efficiency in the Load Forecasts	20
Questions Regarding I&M’s Load Forecast	21
Load Forecasting and Resource Adequacy Issues.....	24
Energy Efficiency in the Load Forecast	25
Avoided Costs.....	29
Risk Analysis	29
Discussion of I&M’s IRP.....	31
I&M’S Preferred Case.....	32
Risk and Uncertainty Analysis	33
Constructing, Evaluating, and Integrating DSM Bundles	33
Avoided Costs.....	34
Load Forecasting Methodology	35
Stakeholder Process.....	36
Summary	36
INDIANA MUNICIPAL POWER AGENCY’S 2015 INTEGRATED RESOURCE PLAN AND PLANNING PROCESS	38
The Load Forecast	40
RESOURCE PLANNING	44
RISK ANALYSIS	46
Summary	47

WABASH VALLEY POWER ASSOCIATION’S 2015 INTEGRATED RESOURCE PLAN AND
PLANNING PROCESS 49

Load Forecasting 51

Resource Planning..... 55

Risk Analysis 57

Energy Efficiency 58

Avoided Costs..... 60

Summary 61

INTRODUCTION

The Indiana Utility Regulatory Commission (IURC or Commission) has a pending Proposed Rule to modify 170 IAC 4-7 Guidelines for Electric Utility Integrated Resource Plans. (See the “Draft Proposed Rule” on the IURC website at <http://www.in.gov/iurc/2674.htm>.) According to Section 2 (h) of the Draft Proposed Rule, the director shall issue a Draft Report on the Integrated Resource Plans (IRPs) no later than 120 days from the date a utility submits an IRP to the Commission. Consistent with the Draft Proposed Rule, the “director may extend the filing deadline for submitting supplemental or response comments.” Section 2(k) of the Draft Proposed Rule limits the report to the informational, procedural, and methodological requirements of the rule.¹ The Draft Proposed Rule continues in Section 2(l) that the report shall not comment on the utility’s preferred resource plan or any resource action chosen by the utility.

¹ **ILLUSTRATIVE TIME LINE:**

December - January (or earlier)

Current cycle utilities develop planning objectives (what is it they want to know), assemble resource operational and other data – including DSM, and begin development of assumptions, scenarios, and sensitivities.

Commission Staff and stakeholders review the prior cycle IRPs (following their November submittals).

January – February (or earlier)

Utilities prepare their load forecasts, make further refinements to their assumptions, scenarios, and sensitivities. Continue to assemble data.

Stakeholders submit their questions, comments, and concerns.

Commission staff continue their review of IRPs and start drafting questions, concerns, and comments for the Director’s Draft Report.

March – April (or earlier)

Utilities prepare an initial IRP analysis, conduct first stakeholder process to obtain feedback on the reasonableness of inputs (e.g., the load forecast), assumptions, scenarios, and sensitivities.

For the current cycle of IRPs, Commission staff meets with utilities and stakeholders to offer comments on the stakeholder meeting and the IRP analysis being done by the utility.

From the previous IRP cycle, commission staff considers questions, comments, and concerns raised by stakeholders and prepares a DRAFT Director’s Report that is focused on questions, comments, and concerns rather than a detailed critique of the IRPs.

Commission staff conducts a Contemporary Issues Technical Conference to consider difficult analytical and technical questions arising from the IRP process.

May – October

Utilities conduct two or three more stakeholder meetings.

Commission staff meets with the utilities and stakeholders to discuss the stakeholder meetings and the information presented during the stakeholder discussions.

May or June (depending on whether there were extensions granted). From the previous IRP cycle, Commission staff consider responses from utilities and stakeholders in formulating the Director’s FINAL Report.

November (subject to no requests for waivers)

Utilities submit their IRPs.

The Draft Proposed Rule is bolstered by recent legislation that requires electric utilities to consider energy efficiency (EE) on as comparable a basis as possible with other resources.

The director commends the following utilities for preparing their IRPs as if the Draft Proposed Rule for the IRPs was in effect. This Draft Report was written to comply with the requirements of the Draft Proposed Rule specified above.

Indiana utilities submitted IRPs on Nov. 1, 2015, with one exception for good cause. The four utilities are

1. Duke Energy Indiana (Duke)
2. Indiana Michigan Power (I&M)
3. Indiana Municipal Power Agency (IMPA)
4. Wabash Valley Power Association (WVPA)

Written comments on the Duke and / or I&M IRPs were submitted by the following and others:

1. Citizens Action Coalition, Earthjustice, Indiana DG, Mike Mullett, Sierra Club, and ValleyWatch
2. City of Ft. Wayne
3. City of South Bend
4. Nathaniel Rose, President of Forest Park Neighborhood
5. Howard Traxmor, Member, Northeast Indiana 350
6. Carolyn N. Vann, Ph.D., Professor of Biology, Emeritus, Ball State University
7. John W. Vann, Ph.D., Associate Professor of Marketing, Ball State University
8. James W. Wingate, Task Force Co-Chair/Muncie Action Plan
9. Edward Wolner

This Draft Report by the director was issued May 20, 2016. Under the Draft Proposed Rule, supplemental or response comments may be submitted by the utility or any customer or interested party that earlier submitted written comments on the utility's IRP. Supplemental or response comments must be submitted

Commission staff and stakeholders begin their initial review of the IRPs.

within 30 days from the date the director issues the Draft Report. The director may extend the deadline for submitting supplemental or response comments.

According to the Draft Proposed Rule, the director shall issue a Final Report on the IRPs within 30 days following the deadline for submitting supplemental or response comments. The director would be pleased to meet with utilities or stakeholders to discuss the Draft or Final Reports.

DUKE ENERGY INDIANA'S 2015 INTEGRATED RESOURCE PLAN AND PLANNING PROCESS

Duke Energy Indiana

Duke Energy Indiana (Duke) is commended for an improved IRP and IRP process; however, there are some questions and concerns for Duke to address. Duke took good advantage of this period of high uncertainty due to the potential ramifications of more stringent environmental regulations to try some innovative scenario construction through the stakeholder process. Due to a lack of urgency to address resource concerns, this IRP seems to have afforded Duke an opportunity to objectively assess different retirement options and potential replacement resources.

Duke's perspective on the importance of Integrated Resource Planning is well stated. In addition, Duke's recognition that the IRP is a snapshot in time and that course corrections can be made as conditions warrant is appropriate:

The resource planning objective is to develop a robust economic strategy for meeting customers' needs in a dynamic and uncertain environment. Uncertainty is a critical concern when dealing with emerging environmental regulations, load growth or decline, and fuel and power prices. Furthermore, particularly in light of the rapidly changing environmental regulations currently impacting our resource planning process, the Integrated Resource Plan (IRP or the Plan) is more like a compass than a road map by providing general direction at this time while leaving the specific tactical resource decisions to Commission filings using then current information. While we have always explained that the IRP is a "snapshot in time," that is especially true this year. For example, while the Company has modeled the EPA's proposed Clean Power Plan (CPP) rule, the final rule differs so much from the proposed rule, the modeling performed to date does not accurately reflect current circumstances and as such, must already be updated. Major changes in the 2015 from the 2013 IRP follow. Duke's IRP page 7.

In this IRP, Duke gave more attention to risk analysis, trying to treat new demand-side management (DSM) resources on as comparable a basis as possible with supply-side resources. Duke also gave attention to innovation in the stakeholder process, including forums and a careful effort to include industrial customers. Again, notwithstanding some important enhancements, Duke should address questions and concerns, including, most significantly, the following:

1. The lack of clarity of the narratives to explain the scenarios and sensitivities is a concern. (The natural gas price forecast narrative was exemplary and should be used as a standard for clear and concise narratives.)
2. The rationale for changes in the load forecasting methodology.
3. The treatment of energy efficiency (EE) on as comparable a basis as possible to other resources. Moreover, the Joint Commenters,² [on page 7 of their comments] raised important questions about the amount of EE that was considered and the need for transparency.
4. Whether the construction of scenarios and sensitivities was sufficient to adequately address the risks faced by Duke.³
5. Information relevant to the IRP narratives should be included in the IRP rather than requiring the reader to consult the Technical Appendix. We recognize formulas and some technical information are better suited to a technical appendix.
6. Minor concerns about the explanatory quality of graphics, including labeling of axis.

As with the 2014-2015 Director's Report, this 2015-2016 Draft Report continues to emphasize some of the more significant IRP concepts such as the risk and uncertainty factors that are primary drivers of all the IRPs that include, but are not limited to, the following general questions and comments with more complete discussion and citations in the text:

- Potential environmental costs such as those related to the Clean Power Plan and the range of potential prices for carbon dioxide;
- Projected natural gas prices;
- Integration of new cost-effective EE and demand response on as comparable a basis as is feasible with other resources. Technological improvements (note the precipitous drop in prices in lighting technology), combined with probable increases in the cost of providing electricity, seem likely to increase the cost-effectiveness of EE and demand response.

² Comments of Citizens Action Coalition, Earthjustice, Indiana Distributed Energy Alliance, Michael A. Mullett, Sierra Club, and ValleyWatch on Duke Energy Indiana's and I&M's 2015 IRPs.

³ DEI defined seven scenarios and developed nine portfolios. However, only three were fully optimized. Three *scenarios* seem to be more appropriately characterized as *sensitivities*, which may have been only partially optimized – if at all – and stakeholder scenarios that were not optimized. Each of the nine portfolios are evaluated under the seven scenarios and provide an analysis with the dimension of seven by nine. However, the process used by DEI is not as clear as it could be.

- Load forecasting, including the appropriate treatment of existing EE and demand response.
- Projected cost of renewable technologies and the cost-effectiveness of integrating renewables into the resource mix. As with EE and demand response, it seems likely that there will be some declining cost and increasing cost-effectiveness that may have been too modestly reflected in the IRP.
- The potential for more customer-owned generation including incipient technologies.
- Regional supply and demand considerations (including transmission) and greater coordination with the regional transmission organizations (RTOs).
- Future Enhancements to all aspects of the IRPs.

The director requests Duke Energy Indiana respond to the following request for clarification. Additionally, the director is interested in Duke's responses to the stakeholders.

Risk Assessment

Scenarios and sensitivities are a primary method of assessing the different risks confronting Duke, and they affect the robustness of the long-term resource plan. In this regard, the number of initial scenarios Duke formulated was admirable. However, ultimately, the number of scenarios that were optimized and provided distinct portfolios was limited to three, which may not be sufficient for evaluating the broad range of risks identified by Duke in its IRP.

With regard to the construction of scenarios and sensitivities, Duke's objective function was to minimize revenue requirements over the various scenarios and resulting portfolios. Other utilities may select a portfolio that minimizes rate increases. A utility also may want to achieve a higher level of reliability in response to a perception of greater risk of having insufficient resources to meet forecasted demand. All of these have legitimacy. It is therefore desirable to discuss these different objectives in the narratives for the various scenarios. Ideally, it would be preferable if these discussions took place during the first stakeholder meeting.

The discussion of the Duke scenario and portfolio development was somewhat confusing and lacking in detail. Although Duke developed seven scenarios, the emphasis throughout seems to be on the portfolios, with little apparent connection between the scenarios and the resource portfolios beyond the three scenarios that were optimized. That is, the development of the portfolios did not seem to be driven by the scenarios.

By way of example, although Duke's risk assessment of the potential cost of carbon dioxide was much more robust compared to the prior IRP, as evidenced by the CO₂ Allowance Price projections, the

predominate prices were below \$57 per ton (in 2035). It is not clear that the one sensitivity that was \$114 per ton affected Duke's consideration because the majority of the price projections was much lower. The Midcontinent Independent System Operator (MISO), for instance, used \$100 for their extreme CO₂ price to provide a bookend to their scenarios in *Initial Results for MISO's Near-Term Analysis of EPA's Final Clean Power Plan*, Dec. 16, 2015 (note this analysis was issued after Duke prepared its IRP). Again, it should be stressed that the CO₂ costs were very speculative at the time that Duke prepared this IRP.

Questions:

- 1. Are we correct that only three scenarios were fully optimized?**
- 2. Could the second three scenarios, where combined cycle units were substituted for combustion turbines, be characterized as sensitivities rather than scenarios? After these substitutions were made, was it only the residual resources that were optimized? If our characterization is accurate, then in retrospect, would Duke agree the selection of just three true scenarios for optimization may not have been sufficient to robustly reflect the risks Duke identified?**
- 3. After the IRP modeling was done and Duke selected a preferred case (page 19) based on the carbon tax, which is different from the no carbon regulation case that might have normally been regarded as a base case (Business as Usual), were either of these scenarios initially optimized with some customer-owned resources such as combined heat and power, wind and solar renewables, and additional EE hardwired? Was any further optimization conducted?**
- 4. Given that the first combined cycle generating unit in the preferred plan would be constructed in the relatively near-term (4 to 5 years or so), does Duke anticipate any changes or actions to influence the timing or operating characteristics of the combined cycle, such as more EE, more demand response, or encouraging more customer-owned resources?**
- 5. It appears that Duke may have unduly constrained the amount of EE prior to being analyzed in the System Optimizer. If the perception is accurate, it raises the concern that Duke might not have been able to deploy additional cost-effective EE and demand response to influence the timing and size of future resources such as the potential for a combined cycle unit in the near term and in the longer term as Duke's need for resources increases. That is, it appears that Duke limited the amount of EE and demand response by assuming the composition and size of the future annual EE portfolio impacts were the same after 2018 (page 76-77 of the IRP). Is this an accurate characterization?**

- 6. If Duke believes our understanding of the treatment and characterization of EE and demand response are not accurate, we would welcome Duke’s response. For future IRPs, and to be consistent with concerns raised by the Joint Commenters [on page 2], involving stakeholders in the development of scenarios, assumptions, review of data, methodological treatment of EE, and other resources might avoid misunderstandings and unnecessary controversy. The director also agrees with Joint Commenters that involving stakeholders in more in-depth reviews of the results may improve confidence in the credibility of the results. A better understanding by all also would benefit proceedings before the Commission.**
- 7. The IRP states on page 9 that retirement analysis for the generation fleet was included in the overall optimization modeling. What is meant by “included in the overall optimization modeling?” How was this done? The description of the portfolios on pages 137-139 indicates that many retirements of generation units were assumed rather than optimized by the model. So, is this a contradiction?**
- 8. On pages 104-105, Duke notes the assumed retirement date for Wabash River units 2-5 is 2016. Duke then goes on to say Unit 6 continues to be evaluated for natural gas conversion and that no decision has been made. However, all the Scenarios considered by Duke on pages 137-139 show Unit 6 retiring in 2016. Question: If no decision has yet been made regarding Unit 6, then why do all the scenarios show Unit 6 as retiring in 2016?**

Constructing, Evaluating, and Integrating DSM Bundles

There seems to be broad agreement that 1) new EE and demand response should be treated as a resource on as comparable a basis as possible to alternative resources; and 2) bundling of new EE and demand response is appropriate. To this end, the director believes Duke made a good effort to appropriately integrate EE and demand response into its IRP. However, it was not clear how Duke constructed the bundles of EE and demand response resources. Moreover, because many of the resource portfolios were predetermined, meaning they were not the result of optimization, it is not clear how the EE and demand response bundles would have been optimized to treat EE and demand response as resources on as comparable a basis as possible to any other resource. Ideally, EE and demand response should be simultaneously optimized with the other resource alternatives, but it is not clear that occurred.

1. Duke’s explanation of the “Measure Life” treatment of existing EE (“roll off”) seems to be an improvement in the 2015 IRP. However, the write-up is not as detailed or as clear as it could be to allow the reader to better understand how the roll off effects are modeled and how this method

impacts the load forecast and the resource analysis. Additional clarity about how the statistically adjusted end-use (SAE) models (and other analysis) capture the roll off effects, how these effects are replaced with the naturally occurring EE, and how new EE is incorporated without the potential for over-estimating (double counting) or underestimating is necessary. (page 35)

Questions:

- a. **A specific numerical example would help to clarify how Utility EE effects are being rolled off. What is an accelerated benefit? How is the accelerated benefit calculated or estimated? How is it determined when the energy reduction would have otherwise occurred?**
 - b. **What are naturally occurring appliance efficiency trends that replace the rolled-off UEE benefits? How are these naturally occurring trends determined or developed? Is it always the result of new appliance or equipment standards going into effect, or can there be another driver?**
 - c. **Page 135 contains a section titled “Identify and Screen Resource Options for Future Consideration.” However, the section includes this sentence: “Projected impacts from both Core and Core Plus EE programs were included.” Question: What does this sentence mean? How were these projected impacts included?**
2. The IRP notes on page 45, for the period 2016-2018, that the portfolio reflects the EE programs that were filed for approval in Cause No. 43955-DSM3 for the period 2016-2018 and were locked-in.

Questions:

- a. **Would Duke agree that, because these programs were not yet approved, these EE programs were too speculative to be hardwired?**
 - b. **If so, would Duke also agree that, as a result of hardwiring these programs, the models were prevented from objectively selecting and optimizing these EE programs in relation to other resources?**
 - c. **Even if the objective was merely to see how much results changed, would it be useful to Duke and stakeholders to examine the optimized results?**
3. The director agrees with the Joint Commenters (page 2) that Duke should provide more detail on the assumptions used and the data supporting the EE effects on Duke’s load shapes. The written discussion of how the new DSM bundles were constructed, analyzed, and integrated into the IRPs

(in a manner that is comparable to other resources) would benefit from more detail and clarity including, as the Joint Commenters observed, information as to how the screening process was conducted. Also, it is awkward to have to go back and forth between the information contained in the IRP and the Technical Appendix to try to understand how the bundles were created.

Questions:

- a. **For future IRPs and recognizing the difficulties, would Duke consider providing sufficient relevant information contained in the public version of the IRP to enable the reader to have a basic understanding and provide more detailed information in an appendix?**
 - b. **Would Duke please provide additional detail on how Duke gets from Potential DSM, as reflected in a market potential study, to the DSM that is included in the IRP analysis?**
4. Because of the increased importance of DSM and in advance of the rulemaking, there is a need for added clarity.

Questions:

- a. **What is the basis or rationale for using the assumption that Duke will be implementing the currently approved and proposed portfolio of EE programs throughout the IRP analysis period?**
 - b. **How were the sub-portfolios developed? There is no discussion of how this was done, such as the data, assumptions, costs, etc.**
 - c. **What are the implications of this assumption?**
 - d. **Did Duke consider alternative assumptions? If yes, what were they, and why were they not used? How was technological change considered in developing the sub-portfolios?**
5. Duke states on page 77 that the incremental sub-portfolios were created using the assumption that additional participation would be obtained for the same programs that exist in the base portfolio but that there are exceptions.

Questions:

- a. **What were the exceptions?**

- b. When exceptions did occur, what was done in the alternative?**
6. Please describe the use and interrelationships among the “System Optimizer,” “Planning and Risk (PaR),” and “DSMore.”

Questions:

- a. Are there incongruities in the modeling inputs (e.g., all 8,760 hours for the PaR versus usually significantly less than 8,760 hours for production costing models) that may affect the credibility of the results? For example, without retaining the chronology of hour (or sub-hour) use during peak periods, the credibility of demand response is questionable.**
 - b. Please provide more detail on how DSMore calculates and utilizes avoided cost in the consideration of EE.**
7. Duke, like other Indiana utilities, is commended for surveying how other utilities construct their DSM bundles to treat them on a comparable basis to other resources.

Questions:

- a. What are the lessons learned that Duke might utilize to enhance its consideration of DSM?**
 - b. To what extent, if at all, was this information from other utilities’ processes incorporated into Duke’s IRP?**
 - c. Does Duke intend to make any changes in its DSM bundling process in future IRPs?**
8. On page 155, Duke states, “Customer behavior may not align with economic incentives further complicating efforts to accurately model EE as a supply-side resource.”

Questions:

- a. What does this sentence mean?**
- b. How is this observation about customer behavior and economic incentives derived from the EE sensitivities?**

The Calculation and Use of Avoided Costs in the IRP

Duke seems to have utilized avoided costs in its IRP analysis. From the stakeholder meetings, it is clear that Duke recognizes the importance of using well-reasoned avoided costs in assessing the viability of EE, demand response, and customer-owned resources in comparison to traditional resources. However, additional clarity would be helpful to detail how avoided costs were calculated and how the models used avoided costs in the IRP.

Questions:

- a. If the avoided cost of the potential combined cycle affected the avoided costs, how did it change the cost effectiveness of DSM, demand response, and other resources?**
- b. In general terms, how does Duke integrate avoided cost calculations in all its scenarios?**

Weather Normalization

1. Even though Duke, like other Indiana utilities, is forecasting low load growth (even negative in some areas), weather remains an important driver for the load forecasts, particularly peak demand. Because peak demand, in turn, is an important driver of most resource decisions, credible normalization of the weather variable used in the 20-year load forecast is important.

Questions:

- a. Could Duke please explain the *weather normalization* process?**
- b. Is our reading of the IRP correct that there are no longer any details on how the weather normalization is done in the IRP? The math would also be helpful.**

Derivation of Peak Demand Estimates

1. It is clear that Duke understands the importance of credible peak demand forecasts as a significant factor in making resource planning decisions that affect the cost of meeting resource adequacy requirements. However, it is not clear how Duke calculated the system peak demand. Nationally, most utilities have experienced increasing demand relative to energy use, which would provide additional impetus for demand response over the 20-year planning horizon of the IRPs.

The peak load methodology seems to have changed from separate summer and winter econometric models to some kind of hybrid econometric/end-use approach. However, the write-up does not have

enough details to make it clear what is being done. The weighting of the month's discussion is particularly confusing. The peak models used to be estimated on days that could produce a peak: 90 degrees and above for summer and below a certain temperature for winter. However, now, Duke's IRP just states that it is a "predetermined threshold" without specifying what that temperature is.

Questions:

- a. **Why?**
 - b. **What threshold was used?**
 - c. **Would Duke please provide additional information to explain how it developed its peak demand? Again, a mathematical example would be helpful.**
2. Consistent with EIA's forecasts, Duke's forecast shows peak demand growing more quickly than the rate of energy sales.

Questions:

- a. **Does Duke anticipate a reexamination of the economic warrant for increased demand response, the value of peak demand reductions due to EE, and incentives for increased customer-owned generation to reduce Duke's peak demand?**
 - b. **Because Duke *may* add a combined cycle (CC) in the relatively near term, the cost of alternative resource solutions seems certain to increase in cost-effectiveness over the 20-year planning horizon. Does Duke agree?**
3. The high and low scenarios were developed using statistical bands at the 95% confidence level. This represents a change from the methodology used in the 2013 IRP in which the first five years were based on high and low economics with statistical bands applied for the remainder of the forecast period.

Questions:

- a. **Why did this change occur?**
- b. **Intuitively, Duke must have concluded the risk bands better assessed risk. However, it seems the previous approach is arguably better than purely statistical bands. Would Duke please provide its rationale and perspective?**

Changes in Load Forecasting Methodology

1. The director commends Duke for continually evaluating the load forecast methods. Because load forecasts are the foundation for IRPs and Duke's operations, additional detail about the rationale for changes as well as possible future changes would be helpful. Duke recognizes that, despite lower forecasted load growth, the potential range of different forecasts poses significant risks to its resource planning. As a result, it is imperative that the load forecasting methodology be credible and clear, changes in methodology are noted, and the rationale for changes are clearly articulated in the IRP discussion of load forecasting.

Questions:

- a. **Because Duke's projections of low load growth are not likely to be a significant driver of resource decisions, would it have been useful for Duke to have a broader risk band on load forecasting? In other words, would a relatively high and low load growth scenario provide additional information about the potential ramifications of over- or under-estimating load growth?**
 - b. **Is our understanding correct that the high and low range of the load forecast was determined by applying the standard error of the FERC-class estimation models using a 95% confidence interval? (page 39)**
 - c. **Why did the change from the past practice of having forecast ranges based in part on macroeconomic drivers occur?**
 - d. **Does the use of statistical bands assume the macroeconomic forecast is correct and all load forecast error is entirely statistical error? In other words, could any errors be driven by inaccurate macroeconomic variable/driver forecasts?**
 - e. **Is there any concern that reliance on statistical bands might obscure problems in the model specifications which, if they occur, would not be corrected?**
2. **The residential forecast.** Duke made several changes to the load forecast methodology [beginning on page 30 of the IRP].

Questions:

- a. **Residential load is modeled with two equations—residential customers and use per customer (UPC)—and the results are then multiplied together to get the residential sales forecast. Residential customers now appears to be an explanatory variable in**

the UPC model itself. Is this accurate?

- b. Does the residential customer model no longer include real per capita income as a driver?**
 - c. The UPC model also includes a driver called “Residential Appliance Intensity.” Is this what Duke refers to on page 31 of the IRP as the “combined impact of numerous other determinants tracked by the Energy Information Administration (EIA) that include the saturation and efficiency of air conditioners, electric space heating, other appliances, the efficiency of those appliances?” It is not completely clear how this information was included in the load forecast. Would Duke please provide a discussion about the rationale for these changes?**
3. As part of continual improvements envisioned by the IRP rule and given the increased deployment of advanced metering infrastructure (AMI) and smart grid, Duke’s thoughts would be appreciated.

Questions:

- a. How does Duke anticipate utilizing the information to enhance load forecasts? For example, will this be used to enhance load research?**
 - b. How does Duke anticipate using the information from AMI, in particular for consideration of EE, demand response, and customer-owned resources?**
 - c. What enhancements, if any, does Duke anticipate making to its future residential load forecasts?**
4. The industrial forecast has changed to include “billing day.” In previous forecasts, “industrial sales” was the lone dependent variable.

Questions:

- a. What is the rationale for the change?**
- b. Why are “Regional manufacturing GDP,” “Electric price relative to other fuels,” and weather no longer drivers in the model?**
- c. Is any significant part of the production process, for any industrial customer, sensitive to weather changes?**

5. Given the increasing importance of the industrial class to the load forecast to the IRP, Duke's perspective would be appreciated.

Questions:

- a. **What steps does Duke intend to consider to improve the insights and credibility of the industrial forecast?**
 - b. **Has Duke considered having its industrial representatives and other experts getting more detailed information?**
6. The commercial forecast now appears to be a hybrid end-use model instead of the econometric model Duke used for many years. This may be appropriate, but we would like to have Duke's rationale for the changes.

Questions:

- a. **By way of examples, why is commercial employment no longer a driver?**
 - b. **Saturations and efficiencies are scaled by square footage for different commercial activity sectors in the model; however, nothing is listed in the model equation. Would Duke please explain?**
7. For future IRPs, recognizing that the commercial class is very diverse, what steps is Duke considering to improve the explanatory value of the commercial forecast. For example:

Questions:

- a. **Has Duke considered grouping the commercial class into more homogeneous subgroups to improve the insights and credibility of the commercial forecasts?**
 - b. **Especially with the potential for higher avoided costs, would greater granularity in the information about the various types of customers provide information to better target demand response, EE, and customer-owned resources?**
8. Regarding agricultural use, stakeholders expressed strong opposition to Duke's use of North Carolina examples (e.g., poultry waste being used to produce fuel on page 97). Stakeholders suggested that the IRP's credibility would be enhanced if Indiana examples were used.

Questions:

- a. **Has Duke considered using Indiana-specific research to assess the potential?**
 - b. **What Indiana data sources might be used to provide the Indiana-specific data?**
9. **Governmental (OPA) model.** As with the industrial forecast, the OPA forecast has changed to “sales per billing day.” In the past, OPA sales alone was used as the dependent variable.

Questions:

- a. **Why did this change occur?**
 - b. **Does Duke plan to make any enhancements to the OPA?**
10. With the substantial change in the resource mix over the next 30 years, there is an expectation that Indiana utilities will give increased consideration to regional developments.

Question:

How does Duke anticipate working with the MISO on enhancements to its load forecasts and long-term resource planning in an effort to improve the credibility and, hopefully, have a positive effect on resource adequacy requirements and provide other benefits?

General Discussion of Duke Energy Indiana’s IRP

Duke experimented with an interesting concept to elicit stakeholder input into the portfolios to be considered in the 2015 IRPs as well as having stakeholder-driven scenarios and sensitivities. From the director’s perspective, this exercise demonstrated that stakeholders and utilities were not that far apart on the portfolios. This was a very gratifying outcome. Maybe this should not be surprising because Duke and its stakeholders share a mutual desire for reliable service at reasonable costs. We hope all utilities will take note of the limited differences between the utilities and stakeholders regarding the ultimate portfolios and have confidence that objective analysis can be conducted by all parties. It also was commendable that Duke retained outside expertise [page 8] to develop 7 discrete scenarios that enhance analytical robustness. The consultants performed the macro-modeling for each scenario using a suite of equilibrium models that defined a set of internally consistent assumptions. However, given that the scenarios were constructed to arrive at specific portfolio mixes, the write-up does not make it clear how the optimization was conducted or even which scenarios were optimized. These concerns were compounded by the general lack of

discussion of the purposes and reasoning for the scenarios and sensitivities. The director⁴ understands that only the first three scenarios were fully optimized, the next three portfolios (arguably sensitivities) substituted combined cycle generating units for combustion turbines (which was a constrained optimization), and the remaining three stakeholder-driven portfolios were not optimized. Hopefully, future IRPs will have collaboratively derived stakeholder scenarios that also will be optimized and the portfolios subjected to additional analysis will have been the result of optimizing for a given set of scenarios.

It should be considered that, because the 2015 IRP analysis was largely completed before the United States Environmental Protection Agency (EPA) issued its Clean Power Plan (CPP) final proposed rules in August 2015, this was an ideal time to experiment with this novel approach because of the uncertainties. However, the director would be hard-pressed to imagine a set of circumstances that would warrant a similar approach in future IRPs because this method puts the thumb on the scale by predetermining the resource portfolio outcomes (especially the substitution of the combined cycles for combustion turbines) rather than allowing the long-term resource planning models to objectively decide the resource outcomes for a diverse set of scenarios. Regardless, the work done modeling environmental regulations – and lessons learned – will be useful in future complex analysis.

To summarize and in the opinion of the director, Duke made substantial enhancements to its IRP. Duke's responses to the questions and requests for clarification posed by the director and stakeholders will facilitate the review of Duke's IRP and aid in the preparation of the final director's report.

⁴ On page 111 (and again on page 130) of the Technical Appendix, Brian Bak explained that 9 portfolios have been developed. Two of these were specifically designed to meet stakeholder suggestions developed at the last workshop. The portfolios are characterized as:

1. *No Carbon Tax (optimized)*
2. *Carbon Tax (optimized)*
3. *Clean Power Plan (optimized)*
4. *No Carbon Tax with Combined Cycle*
5. *Carbon Tax with Combined Cycle*
6. *Clean Power Plan with Combined Cycle*
7. *Distributed Generation (stakeholder suggested)*
8. *Green Utility (stakeholder suggested)*
9. *High Renewables*

On page 116 of the Technical Appendix, Scott Park reminded stakeholders that the three stakeholder scenarios were not optimized.

INDIANA - MICHIGAN'S 2015 INTEGRATED RESOURCE PLAN AND PLANNING PROCESS

As with the 2014-2015 Director's Report, this 2015-2016 Draft Report continues to emphasize some of the more significant IRP concepts such as the risk and uncertainty factors that are primary drivers of all the IRPs that include, but are not limited to, the following general questions and comments with more complete discussion and citations in the text:

- Potential environmental costs such as those related to the Clean Power Plan and the range of potential prices for carbon dioxide.
- Projected natural gas prices.
- Integration of new cost-effective energy efficiency (EE) and demand response on as comparable a basis as feasible with other resources. Technological improvements (note the precipitous drop in prices in lighting technology), combined with probable increases in the cost of providing electricity, seem likely to increase the cost-effectiveness of EE and demand response.
- Load forecasting, including the appropriate treatment of existing EE and demand response.
- Projected cost of renewable technologies and the cost-effectiveness of integrating renewables into the resource mix. As with EE and demand response, it seems likely that there will be some declining cost and increasing cost-effectiveness that may have been too modestly reflected in the IRP.
- The potential for more customer-owned generation including incipient technologies.
- Regional supply and demand considerations (including transmission) and greater coordination with the regional transmission organizations (RTOs).
- Future enhancements to load forecasting, evaluation of demand-side management (DSM), the stakeholder process, databases, analytical tools, scenario construction, and all other aspects of the IRPs.

Indiana Michigan's (I&M's) IRP and IRP process has, in the opinion of the director, made significant improvements. I&M appropriately used this IRP to examine the potential scenarios for the future of its Rockport generating units and the uncertainties due to the potential ramifications of more stringent environmental regulations. Additionally, in this IRP, I&M gave more attention to risk analysis. The risk concepts it considered are exemplary. The improved narratives to describe the scenarios are also commendable as is the increased effort to treat new DSM on as comparable a basis as possible as other

resources. I&M also gave increased consideration of RTO planning and innovation in the stakeholder process that included a concerted effort to include new types of customers. It is noteworthy that Dr. Paul Chodak, Chief Operating Officer, and other top officials participated in the stakeholder process, demonstrating a corporate commitment to the IRP process. Notwithstanding some important enhancements, there are some questions and concerns the director would like I&M to address.

A range of questions and a few concerns may be addressed easily by additional clarification. Most significantly, there are remaining questions and concerns about how EE programs were bundled and evaluated, whether there should have been more expansive risk analysis beyond the future of the Rockport units (e.g., whether some scenario or sensitivities should have been constructed to evaluate industrial DSM), whether I&M gave undue emphasis to AEP East concerns and too little attention to issues related to the PJM Interconnection, LLC (PJM), and the rationale for changes in the load forecasting methodology. Although the consideration of risk metrics was very good, a more expansive discussion of how they were used in the formulation of the IRP would be helpful to the Commission, stakeholders, and other utilities. For example, we recognize that some utilities have an objective function to minimize revenue requirements over the various scenarios and resulting portfolios. Other utilities may select a portfolio that minimizes rate increases. It also is conceivable that a utility may want to achieve a higher level of reliability in response to a perception of greater risk of having insufficient resources to meet forecasted demand. All of these have legitimacy. It is, therefore, desirable to discuss these in the narratives for the various scenarios.

As required in the Draft Proposed Rule, there is an expectation that I&M will build on this good effort by making continual enhancements. To this end, additional information about how I&M (and other Indiana utilities) intend to enhance the IRP effort would be very much appreciated. This includes working more closely on planning with PJM, the appropriate calculation and use of avoided costs, enhancements to the load forecasting efforts, ongoing efforts to integrate probabilistic analysis into the scenario analysis, and incorporating new DSM into the IRP on a comparable basis to other resources.

Including Energy Efficiency in the Load Forecasts

Because load forecasts serve as a foundation for DSM's contribution to resource planning, it is important the Commission and stakeholders understand how the EE programs affect I&M's load forecast and resource planning. The following questions are intended to provide additional clarity that will increase understanding of how the various analytical tools (e.g., blended forecasts, mini-model, the interrelationship of the short- and longer-term forecasts, the PLEXOS model, etc.) were used in the construction of the load forecast as well as the integration of new EE (and demand response) in the resource planning.

Questions Regarding I&M's Load Forecast

1. I&M's long-term load forecast models account for trends in EE (EE) both in the historical data as well as the forecasted trends in appliance saturations as the result of various legislated appliance efficiency standards modeled by EIA. The load forecast utilizes the most current Commission-approved filing at the time the load forecast is created to adjust the forecast for the impact of these programs. (page 8)

Question:

Would I&M please elaborate on how this adjustment was done?

2. On page 16, sec. 2.4.5.1 shows that forecast values for the energy forecast for 2015 and 2016 are taken from the short-term process, with 2017 blending short-term and long-term. Page 23, sec. 2.6.5, "Blended Forecast," states, "In general, forecast values for the year 2016 were typically taken from the short-term process." This section also refers to Exhibit A-13 as providing an indication of which retail load forecast models are used – blended or long-term. Exhibit A-13 clearly states only the long-term forecast was used for the residential, commercial, industrial, and other retail classes.

Question:

The IRP seems to say blended forecast was used at least some of the time, but Exhibit A-13 says only the long-term forecast was used. Would I&M please clarify? If only the long-term forecast was used, why is there so much discussion of the blended forecast methodology?

3. The impact of past and ongoing customer conservation and load management activities, including DSM programs, is embedded in the historical record of electricity use and, in that sense, is intrinsically reflected in the load forecast. The effects on energy sales and demand of approved DSM installations are analyzed separately and subtracted from the blended sales forecast. These will typically extend for a maximum of three years. For the longer-term DSM assumptions, the company models various DSM bundles using the PLEXOS model to identify the optimal DSM portfolio for each year into the future based on expected future market conditions. Exhibit A-12 is referred to as providing the DSM/EE impacts incorporated in I&M's load forecast. (Page 22)

Questions:

- a. **What does the information in Exhibit A-12 reflect? Does it reflect only the impact of historical and ongoing customer and load management activities, including historical DSM programs?**
 - b. **Does the reference to the load impacts of “approved DSM installations are analyzed separately and subtracted from the blended sales forecast” mean the impacts of DSM programs being currently marketed or already approved by the Commission that are to be implemented? Please clarify what is meant by the statement that the load impacts will typically extend for a maximum of three years. Does this mean the load impacts of EE measures installed in 2016 will be subtracted from the load forecast through 2019 and then stop? Why three years?**
4. **I&M notes there were a number of changes to the load forecasting methodology (page 23), and there is a suggestion of future enhancements. The following questions are merely intended to clarify and are not intended to be regarded as being critical.**

Questions:

- a. **Would I&M please describe the changes and the rationale for those changes in the load forecasting methodology?**
- b. **As a clarification, on page 14, with regard to the cooling use in the residential load forecast, should the reference to “heating degree days” be “cooling degree days”, or is this a change to the forecasting methodology?**
- c. **On page 16, in previous forecasts, was street lighting included in the commercial forecast? If so, what was the rationale for the change?**
- d. **If there was a change in the street lighting forecast methodology, for future IRPs, does I&M anticipate giving greater consideration to including increasingly efficient street and highway lighting?**
- e. **If one of the changes in the forecast methodology refers, at least in part, to the residential customer survey on page 25, please describe how the “residential customer survey...in which data on end-use appliance penetration and end-use saturation rates were obtained” was integrated into the load forecast.**
- f. **With reference to page 25, what is I&M’s rationale for not conducting industrial and/or commercial customer surveys to obtain end-use information?**

because I&M didn't include any industrial EE, does this mean that the customer service engineers are not aware of any efforts by their industries to make EE improvements?

Load Forecasting and Resource Adequacy Issues

Because credible load forecasts are essential to the consideration of resource adequacy, the following concerns and questions address the relationship of load forecasting for I&M in relation to AEP East Zone and within the PJM.

1. I&M states, “[F]orecast uncertainty is of primary interest at the system level, rather than the operating company level. Thus, regardless of how forecast uncertainty is characterized, the analysis begins with the AEP System East Zone load.” (page 28)

Questions:

- a. **What is the reason for this statement when each operating company is responsible for its own resource adequacy?**
- b. **The statement of the relationship of I&M as being an integral part of the AEP System East Load Zone seems to be contradicted by the statement on page 127 referring to I&M as a standalone entity in the PJM RTO. Is I&M a standalone system within AEP?**
- c. **If “Company” in Exhibit A-12 refers to AEP System East, does this muddy the waters because it refers to providing the DSM/EE impacts incorporated in I&M’s load forecast? That is, Exhibit A-12 “provides the DSM/EE impacts incorporated in I&M’s load forecast provided in this report. Annual energy and seasonal peak demand impacts are provided for the Company and its Indiana and Michigan jurisdictions.”**
- d. **What does the information in Exhibit A-12 reflect? Does it reflect only the impact of historical and ongoing customer and load management activities, including historical DSM programs?**
- e. **Does the reference to the load impacts of “approved DSM installations are analyzed separately and subtracted from the blended sales forecast” mean the impacts of DSM programs being currently marketed or already approved by the Commission to be implemented? What does it mean that the load impacts will typically extend for a**

maximum of three years? Does this mean the load impacts of energy-efficiency measures installed in 2016 will be subtracted from the load forecast through 2019 and then stop? Why three years?

2. In I&M's development of the load forecast scenarios, it notes the first step is to estimate an aggregated "mini-model" of the AEP East Zone internal energy requirements. The mini-model is intended to represent the full forecasting structure employed by producing the base-case forecast for the AEP System East Zone and by association for the company. After a base-case energy forecast had been produced with the mini-model, low and high values of independent variables were determined. The values finally decided on reflected professional judgement. Then base, high, and low load forecasts are presented for I&M. (pages 28-29)

Questions:

- a. **Would I&M provide more information on how it went from the mini-model for AEP East to developing base, high, and low load forecasts for I&M?**
- b. **Was the load forecast range used to develop I&M's high and low load forecasts the same as what resulted from the mini-model applied to AEP East?**
- c. **Again, why is there a focus on the load forecast uncertainty for AEP East when I&M must operate as a standalone entity in PJM and must meet its own capacity obligations?**

Energy Efficiency in the Load Forecast

The director recognizes the substantial analytical difficulties in treating existing DSM and "rolling off" their effect as well as attempting to treat new DSM on a comparable basis to other resources. With regard to consideration of future EE and demand response, the director would appreciate I&M's responses to the following questions, requests for clarification, and comments.

1. I&M has implemented EE programs for 2015 that provide demand savings of 15 megawatts (MW). An additional 12 MW is expected in 2016 and 10 MW in 2017. This IRP considers attainment of these levels and the subsequent continuation of the program at the same level and has embedded such levels of EE savings into I&M's load forecast. (page 50)

Questions:

- a. **What does "embedded" mean here? Does it mean the 2015-2017 EE savings level was**

subtracted in the load forecast for years beyond 2017?

- b. Does this contradict the statement on page 22 that load impacts will be extended a maximum of three years? Overall, the treatment of historical EE and current programs being implemented today is somewhat confusing and could be clearer. For example, what assurances are there that there is no double-counting?**
2. I&M discusses the difference in the amount of EE demand (MW) included in the load forecast and the amount included in the 2015 DSM Plan filed with the IURC. (pages 50-51)

Comment:

This is very insightful and commendable for I&M to periodically reassess the methodology for estimating the demand reduction due to EE. Especially because the forecasts and recent history suggest that demand seems to be growing at a slightly higher rate than energy use, this continual evaluation is very appropriate.

3. No industrial DSM programs were developed for industrial programs based on the thought that they will, by and large, self-invest in EE measures based on unique economic merit irrespective of the existence of utility-sponsored programs. So, I&M developed EE bundles only for residential and commercial customers. (pages 89-90)

Questions:

- a. Please provide the technical data or research-related literature to substantiate the position that large customers will self-invest in EE measures. Is this position contradicted by AEP's reliance on the EPRI Market Potential Study, which includes the industrial sector?**
 - b. Does this view apply to all industrial customers regardless of size or how significant electricity is as a cost of operation?**
 - c. Did or do I&M customer service engineers discuss the value of development of an industrial sector DSM with their customers? If so, can I&M share that information publically or confidentially?**
4. I&M states that the impacts of such existing I&M DSM programs are propagated throughout the long-term I&M load forecast. (page 89)

Questions:

- a. **What does “existing” mean in this context?**
 - b. **Does it include programs approved by the Commission even if the implementation year has yet to occur?**
 - c. **What does “propagated throughout” mean, and how is it done in the modeling?**
5. I&M states, “The question of how much effort and money is to be deployed towards removing or lowering the barriers is a decision made by state governing bodies (legislatures, regulators or both).” (page 90)

Questions:

- a. **What does this mean with respect to the IRP (and future IRPs)?**
 - b. **Is it reflected in the modeling, and if so, how?**
 - c. **Did this thought affect how EE programs were analyzed or modeled?**
 - d. **How did it affect the EE programs I&M thought were appropriate to include in the bundles for further analysis?**
6. Toward the bottom of page 90, I&M states, “The AP [Achievable Potential] range is typically a fraction of the economic potential range. This achievable amount must further be split between what can or should be accomplished with utility-sponsored programs and what should fall under codes and standards. Both amounts are represented in this IRP as reductions to what would otherwise be the load forecast.”

Questions:

- a. **How is this split done in this IRP?**
 - b. **What is the basis for the split?**
 - c. **How is it decided which programs can or should be accomplished by the utility and which programs can’t for whatever reason? After this split is made, how are these different types of reductions represented in the load forecast?**
7. A determination was made as to the potential level and cost of such incremental EE activity as well as the ability to expand current programs. It was assumed the incremental programs modeled would be effective in 2018. (page 91)

Question:

Would I&M please provide a discussion of the basis on which these determinations were made?

8. I&M used EPRI data to develop bundles of future EE activity for demographics and weather-related impacts of its service territory. (page 92)

Question:

Would I&M please provide more explanation as to how bundles were put together, even an example? Otherwise, it is impossible to judge the modeling of EE. Obviously, many assumptions were necessary to move from EPRI data to what was included in the IRP, but there is little discussion to clarify.

9. I&M discusses market acceptance ratios (MARs) and program implementation factors (PIFs). (page 94)

Questions:

- a. **How are these terms defined?**
- b. **How are these adjustment factors used?**
- c. **Why are they used?**
- d. **How are they developed?**

Comment:

The EPRI Market Potential Study references another report for the development of MARs and PIFs, but it appears that this document is not publicly accessible. This puts a burden on I&M to explain more completely than is done in this IRP.

10. I&M states the overall cost-effectiveness of the EE bundles offered in the model was approximated as part of the analysis. I&M references the California Standard Practice Manual as to methodology. (page 94)

Questions:

- a. **What data was used to approximate the cost-effectiveness?**
- b. **How were the avoided costs calculated, and how were they used in the development of I&M's IRP?**

- c. **How was bundle cost data created?**

Avoided Costs

1. I&M does not include avoided distribution or transmission capacity costs because these are ever changing, based on the location being considered. (page 99)

Questions:

- a. **While recognizing that considering avoided distribution and transmission (T&D) costs makes it difficult to calculate for the reasons cited by I&M, does I&M suggest that these costs are too difficult to calculate in all instances?**
 - b. **Would I&M agree that there are circumstances where the avoided T&D costs may be significant?**
 - c. **Did AEP perform any analysis to demonstrate the sensitivity (or lack thereof) of EE (and demand response and even customer-owned resources) to changes in avoided T&D costs?**
2. On page 110, there is a reference to Table 4-3.

Question:

Where is Table 4-3? Is it in the appendix?

Risk Analysis

1. Do we understand correctly that I&M never let the model optimize fully? The cases make sense given the importance of the Rockport decisions.

Question:

If our understanding is correct that the model was constrained in its optimization, would it have been better for I&M to allow the long-term planning model to fully optimize so as to provide a more objective result, or at least a different result that would provide I&M with additional insights? (page 114)

2. I&M presents a table showing the cases and scenarios that were optimized. This information shows the Rockport Unit 2 Early Retirement being analyzed using only one scenario. (page 115)

Questions:

- a. **Why is only one scenario used to evaluate the Rockport Unit 2 Early Retirement case?**
 - b. **Why is the “Steady State” case the only case evaluated using the high load and low load sensitivities?**
3. I&M presents the preferred portfolio, which differs from all the portfolio cases evaluated using the five basic scenarios. (page 118)

Questions:

- a. **What is the basis for the Preferred Plan?**
 - b. **How was the “Preferred Plan” derived from the previous optimization results for the four cases and five pricing scenarios?**
4. Figure 26 on page 121.

Questions:

- a. **How is non-DSM EE calculated?**
 - b. **Was the calculation made after the fact?**
5. With regard to risk analysis on page 124.

Question:

- Why was the steady state case not included in the risk analysis? It had the lowest cost in Table 22 on page 120. It’s not to say that this was improper, but additional clarification would be helpful.**
6. The risk metric selected by I&M is called the Revenue Requirement at Risk (RRaR). The RRaR is based on the differential between the median and 95th percentile result from the multiple runs. Figure 33 on page 126 illustrates the RRaR (expressed in terms of a levelized monthly bill impact) and the expected value. (page 125)

Questions:

- a. **Why was this RRaR risk metric selected?**

- b. What other risk metrics are available in the PLEXOS modeling analysis? Please describe and define the other risk metrics available but not used.**
7. See Figure 33 on page 126. The preferred portfolio has the highest or second highest sensitivity based on RRaR.

Questions:

- a. Did I&M consider evaluating the portfolios with other risk metrics? Please explain. Why did I&M not use or include the steady state portfolio if for no other reason than as a comparison?**
- b. Does the lack of a steady state portfolio make it more difficult to understand the preference for the preferred portfolio?**

Discussion of I&M's IRP

Given that I&M appropriately used this IRP largely to evaluate the conditions under which it made sense to retire one or more of the Rockport units and stakeholders seemed to be largely in agreement with this, I&M should take confidence that I&M's perspectives were not significantly different from those of stakeholders. Hopefully, I&M and stakeholders will have greater confidence in their ability to narrow areas of disagreements in important aspects of the IRPs. To this end, I&M provided a well-reasoned framework for its IRP. However, I&M could have been more expansive in its assessment of other potential risks.

An Integrated Resource Plan (IRP or Plan) explains how an electric company anticipates meeting the projected capacity (i.e., peak demand) and energy requirements of its customers based on the information available at this time. In accordance with the Indiana Utility Regulatory Commission's (Commission) proposed IRP rule, Indiana Michigan Power Company (I&M or Company) is providing an IRP that encompasses a 20-year forecast period (2016-2035). I&M's 2015 IRP has been developed using the Company's current assumptions for:

- *Customer load requirements – peak demand and energy;*
- *Commodity prices – coal, natural gas, on-peak and off-peak power prices, capacity and emission prices;*
- *Supply-side alternative costs – including fossil fuel and renewable generation resources; and*
- *Demand-side program costs and analysis.*

This IRP also factored in a prudent bias to continue I&M's progress toward even lower emission generation. The traditional financial evaluation of the options indicated that I&M could accelerate the installation of renewable resources without an inordinate impact on customer rates. It also indicated that the lower cost of retaining both Rockport units over retiring one of the Rockport units prior to 2035 was highly dependent on assumptions and varied from near break-even to over \$300M in cost savings in the scenarios which were evaluated. As the IRP is regularly updated, I&M will continue to examine paths to reduce emissions while maintaining reliability and retaining a low cost advantage for customers. ES-1

I&M'S Preferred Case

To meet customers' future energy requirements, I&M has carefully considered the continued operation and the ongoing level of investment in its existing fleet of assets including its efficient base-load coal plant (Rockport Units 1 and 2), and its nuclear facility, the Donald C. Cook Nuclear Plant (Cook Plant). Another consideration in this 2015 IRP is the increased adoption of distributed rooftop solar resources by I&M's customers. While I&M does not control the extent this resource is deployed, it recognizes that distributed solar will likely offset a portion of I&M's resource requirements. Keeping these considerations in mind, I&M has developed a plan to provide adequate supply and demand resources to meet its peak load obligations for the next twenty years. The key components of this plan are for I&M to:

- *Invest in environmental control equipment to allow Rockport Units 1 and 2 to continue compliant operation under known or anticipated environmental regulations*
- *Continue operation of the Cook Plant through, minimally, the remainder of its current license periods*
- *Add 1,235 MW of Natural Gas Combined Cycle (NGCC) generation in 2035 to replace Cook Unit 1, assuming it is retired in 2034*
- *Add 600 MW (nameplate) of utility owned solar resources beginning with 20 MW in 2020 and an additional 30 MW in 2021*
- *Add 1,350 MW (nameplate) of wind resources beginning with 150 MW in 2020*
- *Implement demand-side resources in the form of additional energy efficiency programs*
- *Recognize that residential and commercial customers will add distributed resources, primarily in the form of residential and commercial rooftop solar*

It is important to note that I&M's IRP is based upon the best available information at the time of preparation. Because changes that may impact this Plan can, and do, occur without notice, this Plan is not a commitment to a specific course of action. The future is highly uncertain, particularly in light of current economic conditions, access to capital, the increasing use of renewable generation and end-use efficiency, as well as current and future laws and environmental regulations, including the U.S. Environmental Protection Agency's (EPA) Clean Power Plan (CPP). The implementation action items as described in the Plan are subject to change as new information becomes available or as circumstances warrant. ES 1-2

Risk and Uncertainty Analysis

Again, it is gratifying that I&M used the 2015 IRP to conduct an examination of Rockport's future. Given the significant uncertainties about the implementation of the Clean Power Plan and the fact that I&M is in a low, or even a declining, load growth environment and new resources may not be needed except to replace retiring facilities, the concentration on Rockport's future seems appropriate. However, for future IRPs to assess replacements for retiring resources, the director trusts I&M will give greater consideration to other resources – particularly in the context of the PJM regional markets – as well as an ongoing assessment of Rockport's future. In future IRPs, incorporation of greater emphasis on probabilistic methods would be beneficial. For example, I&M's assessment of future costs of renewable energy and EE seemed very conservative. Scenarios and sensitivities that have a broader bandwidth of costs and their associated probabilities might provide value to the credibility of future IRPs. In addition to ongoing consideration of the potential ramifications of environmental policies, regional supply and demand considerations, and natural gas prices, other drivers such as load forecasts might also benefit from having more expansive risk-based analysis within scenarios and sensitivities.

I&M is commended for its improved narratives, but more robust consideration of risk will require greater attention to narratives that are well-reasoned. The importance of well-developed and internally consistent narratives cannot be overstated for facilitating the review of the IRPs. Many of the questions and comments in this Draft Report might have been answered by clearer narratives. Moreover, greater attention to narratives also might reduce misunderstandings among the various stakeholders, which should benefit regulatory proceedings.

Constructing, Evaluating, and Integrating DSM Bundles

The evaluation of new EE on as comparable a basis as reasonably feasible to traditional resources is a difficult task, and the methodologies are undergoing critical scrutiny. To be clear, there does not seem to

be a consensus on the approaches to integrating EE into the IRPs. However, as part of the evolution, the director would like additional information on how I&M constructed the EE bundles and how they were evaluated before and within the IRP.

The director believes I&M made a credible effort to treat new EE comparably to other resources, but the director would like more detailed discussion and some examples. Additional information would be helpful, beyond the information in Section 4.4 and the general statement on page 92 and in Tables 12 and 13:

I&M utilized this data to develop ‘bundles’ of future EE activity for the demographics and weather-related impacts of its service territory.

For example, how did I&M go from “achievable potential” (AP) based on the Report by the Electric Power Research Institute (EPRI) to the High Achievable Potential (HAP) and then to the EE that was actually used in formulating the EE bundles if the amounts of EE were different? That is, because HAP is more costly and would require a more aggressive implementation, it is not clear how HAP affected the construction of the EE bundles. The director also noted that Tables 12 and 13, while providing information on the various bundles, do not include information on the peak (either maximum demand on specific T&D elements or demand coincident with I&M’s peak demand) reductions for the bundles.

The Commission has high regard for the Electric Power Research Institute and endorses selective use of borrowed information and collaborative projects with other utilities as a means of achieving cost-effectiveness and robustness. However, the director would appreciate I&M’s thoughts on whether a more tailored approach to I&M’s service territory would be more appropriate.

Avoided Costs

Not including T&D related costs in the calculation of avoided cost is understandable because doing so is difficult. However, as I&M seems to recognize, omitting these costs can understate the value of EE, demand response, and customer-owned resources. Just as importantly, the failure to include T&D can inappropriately skew the cost-effectiveness of projects that the utility may deem appropriate to improve the efficiency of the T&D system. Consideration of efforts to reduce line losses (integrated Volt –Var Control), for example, might not pass muster without consideration of the avoided costs. Because inter-dependencies of generation and T&D from the local level to the bulk power markets are increasing, it seems appropriate that a more expansive view of avoided cost would be appropriate. To accentuate the point, the penetration of roof-top solar and other customer-owned resources or distributed resources will become a more pressing issue for I&M and its customers, as well as having implications for PJM. It is certainly appropriate to learn

from utilities in other states such as Arizona, California, Colorado, and Nevada that are already confronting this difficult issue, but it may be beneficial for I&M and its customers to have a plan to address the issue that would include a more comprehensive approach to avoided cost.

Load Forecasting Methodology

Overall, the forecasting process used by I&M seems credible. However, there are some questions and, potentially, a few concerns. As suggested by the questions posed, the major questions and concerns are how the different models fit together, how existing EE is “rolled off” the forecast, the rationale for changes in the forecast methodologies, the industrial forecasting methodology beyond the short term, and what potential changes I&M is contemplating for future IRPs.

Because of the direct importance of industrial forecasts and the secondary (and beyond) implications for commercial and residential forecasts, the industrial forecasting process is of particular concern. Industrial forecasts are inherently difficult, so the concerns are focused on what might be done to improve the informative value of the industrial forecasts.

Questions:

- 1. For future forecasts should I&M give some effect to industrial DSM?**
- 2. Notwithstanding, I&M’s legitimate rationale for Indiana law that permits industrial customers to opt out of utility-sponsored DSM initiatives, is it reasonable to assume industrial customers will capture all cost-effective “organic” DSM (DSM that would be undertaken without input or incentives from the utility)?**
- 3. Do I&M’s customer service engineers provide I&M with information of organic DSM (including demand response and customer-owned generation) that industrial customers are planning to implement?**
- 4. Would it be reasonable to include various amounts of DSM as scenarios or sensitivities even if they were not attributable to a change in Indiana law or any specific impetus?**

The director’s concern is that the lack of inclusion of organic EE would overstate the industrial load forecast. It may be that the lack of inclusion of demand response would also result in over forecasting. While recognizing the difficulty of estimating customer-owned generation, the lack of inclusion of customer-owned generation can also overestimate the load requirements to serve industrial customers. Giving some effect to potential DSM, without specificity regarding its origin, may also provide I&M with

useful information to better gauge the potential risks of over-forecasting industrial usage. Regardless of its source, over-estimating the industrial load forecast would, in turn, bias the model's selection of the more optimal resource mix and adversely affect I&M's calculation of resource adequacy requirements.

While appreciating the daunting task of forecasting industrial load requirements, there is also the concern that I&M could be underestimating industrial load requirements. Arguably, under-forecasting industrial load could result in more severe financial and reliability concerns than over-forecasting load requirements of this important group of customers.

Stakeholder Process

I&M had a commendable stakeholder process. Again, having Dr. Paul Chodak and other top officials participate in the stakeholder meetings demonstrates I&M's strong commitment to the IRP process. I&M made a very good effort to enlarge stakeholder participation by contacting stakeholders that participated in its last IRP process, intervenors in its last rate case, and its 30 largest commercial and industrial customers. I&M held its first stakeholder meeting in March 2015. During this introductory meeting, I&M said:

Stakeholders were presented with basic IRP planning information, I&M's IRP study plan and assumptions and were asked to provide comments on portfolio components, resource attributes, and economic scenarios and risk considerations. [page 2]

While I&M held a stakeholder conference call in May and a second meeting in June to review stakeholder comments (e.g., load forecasting and evaluation of resource options, including DSM, treatment of risk analysis, and the implications for the IRP analysis), the director hopes that, given a three-year IRP cycle, I&M will consider greater involvement by stakeholders in the formulation of scenarios and assumptions.

Summary

I&M's 2015 IRP represents a significant improvement in both the process and planning analysis. First, I&M used the IRP for its intended purpose to provide company decision makers, its stakeholders, and the Commission with an analysis of important decisions such as the long-term status of the Rockport Station rather than merely because of the IRP Draft Proposed Rule requirements. In this regard, I&M was responsive to stakeholder input. Secondly, it is very commendable that I&M's stakeholder process was well supported by top management and top analysts. Thirdly, I&M made a good effort to integrate increased risk analysis into the IRP, to use state-of-the-art long-range planning tools, to improve the load forecasting, to treat EE on a comparable basis to other resources, to incorporate more information about the PJM

planning that may affect I&M's IRP, and to improve the narratives to describe the scenarios and assumptions.

It is worth reiterating that this round of IRPs was against the backdrop of the uncertainties around the potential ramifications of the Clean Power Plan and state legislation, with the Final CPP Rule being adopted after I&M produced most of its analysis. Even with the Final CPP Rule, there was considerable uncertainty about the cost of CO₂, Indiana's compliance strategy, and the compliance mitigation measures that might be employed. State legislative changes regarding EE and its role in the IRP process changed in this IRP cycle, which provided additional uncertainties that complicated the analysis.

Although the director has several questions and a few comments, these requests for clarification should not detract from the significant improvements made by I&M in this IRP cycle. As stated previously, the IRP Draft Proposed Rule anticipates that all Indiana utilities will make continual improvements in all aspects of the IRP.

INDIANA MUNICIPAL POWER AGENCY's 2015 INTEGRATED RESOURCE PLAN AND PLANNING PROCESS

As with the 2014-2015 Director's Report, this 2015-2016 Draft Report continues to emphasize some of the more significant IRP concepts such as the risk and uncertainty factors that are primary drivers of all the IRPs that include, but are not limited to, the following general questions and comments with more complete discussion and citations in the text:

- Potential environmental costs such as those related to the Clean Power Plan and the range of potential prices for carbon dioxide;
- Projected natural gas prices;
- Integration of new cost-effective energy efficiency (EE) and demand response on as comparable a basis as feasible with other resources. Technological improvements (note the precipitous drop in prices in lighting technology), combined with probable increases in the cost of providing electricity, seems likely to increase the cost-effectiveness of EE and demand response.
- Load forecasting, including the appropriate treatment of existing EE and demand response.
- Projected cost of renewable technologies and the cost-effectiveness of integrating renewables into the resource mix. As with EE and demand response, it seems likely that there will be some declining cost and increasing cost-effectiveness that may have been too modestly reflected in the IRP.
- The potential for more customer-owned generation including incipient technologies.
- Regional supply and demand considerations (including transmission) and greater coordination with the regional transmission organizations (RTOs).
- Future enhancements to load forecasting, evaluation of demand-side management (DSM), the stakeholder process, databases, analytical tools, scenario construction, and all other aspects of the IRPs.

Indiana Municipal Power Agency's (IMPA's) IRP and IRP process has, in our opinion, significantly improved in its quality, credibility, and detail. The improvements in IMPA's IRP process are particularly noteworthy because its corporate structure limits coordination with its members on load forecasting and demand-side management. The director agrees that IMPA's general statement on IRP objectives is a reasonable approach but would observe that some tension exists between (a) minimizing revenue

requirements and minimizing customers' bills, (b) the intrinsic value of diversity of resources and the cost-effectiveness of those competing resources, and (c) short- and longer-term risks:

Integrated resource planning involves the consideration of both supply-side and demand-side resources to meet the future needs of an electric utility and its customers. Both types of resources are compared based on their ability to meet the utility's objectives. IMPA's primary objective in developing its IRP is to minimize the price of electricity to its member utilities and their customers, while maintaining a reliable and environmentally responsible electricity supply. Additional objectives include minimizing risk through a diverse mix of resources and maintaining flexibility to respond to changing economic and regulatory conditions. [page 3-17]

IMPA's expansive consideration of different risk analytics was excellent and a good example for other utilities to follow. Moreover, IMPA constructed five distinct scenarios to better bracket the range of risks confronting IMPA (pages 10 – 60):

- a. Status quo
- b. Retrenchment
- c. Global economy
- d. Shifting gears
- e. Green revolution

In addition to a good discussion of risk metrics, it is clear that IMPA devoted considerable attention to improving the explanatory value of the narratives to describe the five distinct scenarios. It also is commendable that IMPA made an increased effort to treat new DSM resources on as comparable a basis with other resources as possible. Because IMPA operates in both PJM and MISO, it seemed to have the best understanding of how to coordinate its planning and operations with the two RTOs and integrate that into its IRP. The enhancements made by IMPA in this IRP are significant; however, the director would like IMPA to address some questions and concerns.

Most of the questions and the few concerns are probably easily addressed by additional clarification. Most significantly, questions and concerns remain about how the load forecast was constructed and how the EE programs were bundled, evaluated, and integrated into IMPA's IRP. Although the consideration of a wide variety of risk metrics was excellent, a more expansive discussion of these risk measures actually used in the formulation of the IRP would be beneficial.

Because IMPA is a wholesale provider of electricity, the objective function(s) may be different from that of a vertically integrated utility. For example, we recognize that some utilities have an objective function to minimize revenue requirements over the various scenarios and resulting portfolios. Other utilities may select a portfolio that minimizes rate increases. It also is conceivable that a utility may want to achieve a higher level of reliability in response to a perception of greater risk of having insufficient resources to meet forecasted demand. All of these, and variations of these, have legitimacy. It is, therefore, desirable to discuss these in the narratives for the various scenarios. For IMPA, is it more meaningful to minimize revenue requirements or the delivered wholesale price of electricity to ultimate customers? IMPA's thoughts on the appropriate objective function would be most welcome.

As required in the Draft Proposed Rule, there is an expectation that IMPA will build on this very good effort by making continual enhancements. To this end, additional information about how IMPA (and other Indiana utilities) intend to enhance the IRP effort would be very much appreciated. This includes working more closely on planning with MISO and PJM, the appropriate calculation and use of avoided costs, enhancements to the load forecasting efforts, and ongoing efforts to integrate probabilistic analysis into the scenario analysis and incorporate new DSM into the IRP on a comparable basis to other resources. IMPA's thoughts on these matters would be appreciated.

As with the 2014-2015 Director's Report, this 2015-2016 Draft Report continues to emphasize some of the more significant IRP concepts such as the risk and uncertainty factors that are primary drivers of all the IRPs that include, but are not limited to, the following general questions and comments:

The Load Forecast

IMPA's IRP records a 2014 coincident (IMPA) peak demand of 1,163 MW and 6,225,553 MWhs and is forecasting that its peak demand and energy will increase about 0.5% per year (page 1-11). IMPA's projected load growth is not a major risk, but as IMPA notes, it has experienced increases and decreases in membership and this dynamic could pose risks that should be considered even if they are deemed to be low-probability events. The structure of IMPA compared to vertically owned utilities poses some differences and difficulties in forecasting, planning, and operations (e.g., as noted by IMPA on page 4-20, "IMPA does not have the necessary retail load information to draw conclusions concerning disaggregation of load shapes by customer class or appliance," which particularly affects the planning and operations of EE and demand-response programs). This should not be considered as a criticism. Rather, our questions and comments are intended to elicit a discussion from IMPA.

The director also notes that IMPA forecasts peak demand and energy to both increase by 0.5% while many Indiana utilities and the Energy Information Administration have found that the peak demand might be growing faster in relation to energy use. If this relationship is changing, it could affect the cost-effectiveness of demand response and EE.

Comments and Questions:

1. On pages 5-33, IMPA states that its forecast model excluded 24 months of data in 2009 and 2010 to better analyze the base trends and growth by removing the effects of much of the severe recession. The director would appreciate IMPA's thoughts on the following commentary:

IMPA uses an auto-regressive approach (Auto-Regressive Integrated Moving Average [ARIMA]) that is based on historical patterns of the load rather than a forecasting method that utilizes a relationship between energy use and/or demand based on a set of explanatory variables.

IMPA recognized its ARIMA model, because it is based on trends, was not useful for adjusting for the effects of a recession (or any other extraordinary event) to attempt to explain pre- and post-recession use of electricity. That is, a recession wreaks havoc on an ARIMA forecasted result because there is no corresponding downturn in a specific driver(s) to correlate with the downturn in load caused by the recession. Similarly, the addition or subtraction of members can render an ARIMA method problematic.

An ARIMA model has value as a short-term forecasting method in which the values are relatively stable and linear but not when there is dramatic instability such as that caused by the recession. Creating a dummy variable for a selected period(s) of history, especially recent history, is concerning.

IMPA's choice of the ARIMA model might be convenient due to IMPA's structure. In some sense IMPA's relationship with its members in preparing load forecasts has similarities to the preparation of load forecasts by the MISO and PJM. However, the MISO and PJM rely heavily on the load forecasts of member utilities and IMPA does not have that input from its member systems. It should be noted that MISO lists this as an unacceptable approach in its forecasting methodologies whitepaper. In addition to IMPA's comments on the characterization of IMPA's load forecasting approach, the director would appreciate IMPA's thoughts on potential improvements in the load forecasting process.

2. **IMPA's historical energy requirements include EE reductions from 2011 through 2014.**

Apparently, IMPA added the energy from these programs back into the historical energy in an attempt to analyze naturally occurring load growth.

Questions and Comments:

- a. This seems contradictory. Would IMPA please address this seeming inconsistency?**
 - b. Because IMPA is no longer implementing significant EE programs, concern about double-counting past energy and peak reductions due to DSM might not be a major concern for the forecast of future load. The concern for double-counting of past DSM may occur if historical use is not adjusted due to the amount that past DSM programs have reduced the naturally occurring load requirements; also the lack of adjustment might feed forward into lower forecasts. The director recognizes that accurately measuring the changing effects of EE (a.k.a. “roll off”) is daunting and there is no universally accepted approach. However, is IMPA putting its thumb on the scale to try to offset its other thumb on the scale that resulted from the change in load levels due to DSM?**
 - c. Although some legitimate concerns exist for potential double-counting, there are a couple of considerations. First, the higher efficiency buildings and devices that were incentivized by the DSM programs are still in place. These prior DSM initiatives will result in less energy use in the future. Second, DSM programs tend to have spillover effects beyond the program itself, and those effects are also still present. Thus, it is possible to miss some of the effects of past DSM on future load requirements, depending on how firmly you push down on the scales.**
- 3. Is it accurate to say that IMPA used only one base load forecast for all of its scenarios? At least, no other forecasts are discussed in the load forecast chapter. Appendix D, page IX, Figure 2 shows the potential energy forecast and the net energy forecast.**

Questions and Comments:

- a. Is the net energy forecast the forecast IMPA used as the base forecast in the IRP? Is the difference between the two forecasts the level of historic EE for the years 2011-2014? Why is the difference constant over the forecast period? Should not the effects of EE measures installed for the period 2011-2014 decrease and, eventually, disappear over time?**
 - b. Given the relatively small changes in the anticipated forecasts, having a single forecast**

might be appropriate IF the forecast was sufficiently credible under a range of uncertainties. However, because the trending analysis (ARIMA) may be problematic (including the possibility of adding or subtracting members or a corporate decision to embark on significant DSM to influence future resource requirements or comply with environmental requirements), would IMPA agree that having different forecasts to more fully assess potential risks could provide some important insights?

5. The load forecast model uses heating degree days (HDDs), cooling degree days (CDDs), Indiana real per capita income, U.S. unemployment, peak days, and off-peak days.

Question:

How does this model capture the effects of improving efficiency over time?

6. Regarding the generated load forecasts for each of IMPA's five load zones.

Question:

Would IMPA please clarify how these were done? Then, is it correct to say that these were done in the same basis as power is generated into MISO and PJM?

7. IMPA, on page 5-36, discusses methodology used to weather normalize the load data.

Questions:

- a. **Is our characterization correct that, in essence, IMPA is back-casting to find load under normal weather with the assumption that nothing else changes?**
 - b. **This is probably a reasonable practice, but is this characterization accurate?**
8. Given the low projected demand and energy sales growth rates, it is not surprising that IMPA's resource requirements have not experienced significant changes.

Comments:

IMPA's analysis of potential retirements due to potential environmental regulations, age, and operational characteristics seems well-reasoned. Historically, IMPA has been very proactive in taking advantage of relatively low market rates from MISO and PJM while searching for opportunities to partner with other power suppliers as a means of reducing financial and reliability risks [page 2-15]. It is, then, commendable that IMPA is

considering 300 MW participation in a 500 MW combined cycle facility (by 2021 and 2022) in anticipation of the expiration of a Purchased Power Agreement (100 MW) in 2020 and the retirements of Whitewater Valley Stations 1 and 2 in 2022 [page 1-13 and the table on 1-14].

RESOURCE PLANNING

Assessing Existing Generation Units

1. It is gratifying that IMPA's resource planning allowed all IMPA-owned units to be considered for retirement in the capacity expansion modeling analysis rather than relying on somewhat arbitrary assumptions such as the age of the units. IMPA assumes, for purposes of the IRP, that the diesel units at Rensselaer will retire at the end of 2016, but a final decision has not been made as of this IRP. (page 6-41)

Questions:

- a. **Is it correct to assume that the City of Rensselaer and IMPA agreed to the parameters for evaluating the retirement of the units?**
- b. **Did MISO express any concerns about the retirements?**

Renewable Resources

2. IMPA's resource planning seems to give reasonable treatment to renewable resources. The current plan assumes 50 MW of solar park development over the next five years in addition to the existing 13 MW. (page 6-43)

Comment:

It is gratifying that IMPA allowed the resource planning model to add renewable energy additions if the model found them to be the most cost-effective resource alternative.

Energy Efficiency

3. Although IMPA mentioned that EE and demand response was included in the expansion analysis and that pricing of EE and demand response was based on IMPA's experience and supplemented with research from the ACEEE, nothing more was detailed in IMPA's analysis. (page 6-43)

Question:

Would IMPA please provide additional detail to better explain what was done?

4. Pages 13-105-107 discuss DSM options. Utilizing IMPA's experience with EE programs, the cost characteristics, hourly patterns, load factors, and coincidence factors were modeled.

A critical step in modeling EE is to develop hourly EE patterns. The hourly patterns vary by type of measure, time of day, day of week, and month. The hourly patterns of the various measures are aggregated into a single 8,760 hourly "per unit" pattern.

It is recognized that there is a finite amount of less expensive EE that can be obtained in any year, after which the next set of measures becomes more expensive. As a result, IMPA developed an EE Investment Hierarchy.

An aggregate EE hourly pattern is created from a variety of residential, commercial, and industrial measures. The aggregate EE represents the types of EE measure we know and serves as a proxy for new measures that will undoubtedly be developed in the future.

The aggregate EE is broken into three investment levels, which are progressively more expensive. The three levels contain 10 blocks, and each block is equivalent to 0.42% of IMPA's load. If all 10 blocks were chosen, that would add 4.2% of EE in that year. IMPA felt it was important to make available large amounts of EE, albeit at a higher price, to provide a DSM choice in carbon scenarios where avoided cost will be high. A fixed component was added to each block to account for indirect expenses such as administration, marketing, and Evaluation, Measurement, and Verification (EM&V).

Questions and Comments:

The description is good, but it still needs more detail to understand what was done. For example, what measures were included in developing the aggregate per unit efficiency pattern? How were the three investment levels determined? Is each block within an investment level identical? Are the blocks across the three investment levels identical except for costs? How did the costs of each block change over the forecast period? How is technological change accounted for?

5. IMPA makes no assumptions as to future environmental rules or laws. For purposes of this analysis, it is assumed that all future resource options comply with the existing environmental rules in place at the time of installation. (page 7-50)

Questions and Comments:

It is not clear what these two sentences are saying. IMPA says it makes no assumptions about future environmental rules or laws but then goes on to reference all future resource options comply with the existing environmental rules in place at the time of installation. Does this mean IMPA assumes only those environmental rules that exist today are to be met by future resource options? How does IMPA define an existing environmental rule? Is a rule that is proposed today an existing rule or a proposed rule? Or must the rule be settled law and regulation?

RISK ANALYSIS

1. IMPA identified five distinct themes that are expected to have the greatest impact on the future energy business environment over the next 20 years: (a) Status quo; (b) Retrenchment; (c) global economy; (d) shifting gears; and (e) green revolution. (page 10-60)

Question:

- a. **On page 10-60, is it accurate to say that the three scenarios (global economy, shifting gears, and green revolution) were developed to address the ramifications of the CPP rule?**
2. IMPA focuses on levelized average system rates in the vast majority of risk metrics presented. IMPA presented one graph with levelized PVRR for the five plans. The levelized value is the mean value of the 50 stochastic draws. IMPA seems to recognize that a difference exists in how plans perform when measured on ASR versus present value revenue requirement.

Questions and Comments:

It would have been helpful if IMPA presented a figure similar to Figure 107 on page 15-162 with the horizontal axis being PVRR instead of levelized ASR. This raises an important issue for all utilities to more fully understand the risks and uncertainties they face--specifically, whether a utility, especially a wholesale provider, should focus on rates or revenue requirement when trying to evaluate resource options. Regardless, should all the information be presented so that it can be more completely addressed by policymakers? IMPA's thoughts on this matter would be appreciated.

3. IMPA's IRP demonstrates that Plan 02 is always to the left of and above Plan 01, but yet IMPA chose Plan 01 as the preferred plan in Chapter 16.

Question:

Please explain the rationale for selecting Plan 01. Given the risk metrics presented in the earlier pages, would IMPA agree that this was not necessarily a slam dunk decision? The intent of these questions is to better understand how IMPA uses the information presented in the various risk metrics to inform its decisions. (page 15-162)4. IMPA seems to have conducted a reasonable review of potential risk metrics, but it is not clear how these various measures were considered and used.

Question:

Is it accurate to say that other risk metrics were considered by IMPA but were not presented? If yes, what were those risk measures and why were they ultimately not presented?

Summary

IMPA's 2015 IRP represents a significant improvement over prior IRPs. In particular, the director commends IMPA for substantially improved discussions of scenarios, greater attention to the integration of risk analysis into the IPR process, and coordination with the MISO and PJM.

The clarity of the IRP was enhanced by the graphic representations. IMPA's IRP was very readable and well presented.

There were some questions and concerns, primarily about the load forecasting process and what may be too much reliance on ARIMA forecasting methods. Aside from normal load forecasting risks (unexpected load growth or losses), IMPA's potential hypothetical risk of adding or losing members would seem to be a risk that IMPA might give greater attention to in future IRPs.

Given IMPA's structure and its relationship with its members, it isn't clear how avoided costs were used or how avoided costs might be used in the future to provide better information for assessing the relative merits of different resources.

It also isn't clear whether the structure of IMPA might be better served by an objective function that minimizes the ultimate consumers' bills rather than the revenue requirement (levelized average system

rates) for IMPA. Recognizing there are merits to both approaches, IMPA's perspective would be most welcome.

Given the significant changes in IMPA's resource mix and the changing composition of resources in the MISO and PJM and the Eastern Interconnection, the director trusts IMPA will continue to make efforts to interject risk analysis into all aspects of the IRP from the development of load forecasts to the modeling and evaluation of a wide range of scenarios. Although the narratives related to the scenarios were improved from prior IRPs, future IRPs would benefit from elaboration and greater clarity. Again, consistent with the draft IRP rule, the director would welcome greater discussion of potential enhancements to all phases of the IRP process. Expanded discussions of the load forecasting methodology; integration of enhanced data into the load forecasts; and the evaluation of EE, demand response, and the potential ramifications arising from increasing penetration of customer-owned resources would be beneficial.

WABASH VALLEY POWER ASSOCIATION's 2015 INTEGRATED RESOURCE PLAN AND PLANNING PROCESS

As with the 2014-2015 Director's Report, this 2015-2016 Draft Report continues to emphasize some of the more significant IRP concepts such as the risk and uncertainty factors that are primary drivers of all the IRPs that include, but are not limited to, the following general questions and comments with more complete discussion and citations in the text:

- Potential environmental costs such as those related to the Clean Power Plan and the range of potential prices for carbon dioxide.
- Projected natural gas prices.
- Integration of new cost-effective energy efficiency (EE) and demand response on a comparable basis as feasible with other resources. Technological improvements (note the precipitous drop in prices in lighting technology), combined with probable increases in the cost of providing electricity, seem likely to increase the cost-effectiveness of EE and demand response.
- Load forecasting, including the appropriate treatment of existing EE and demand response.
- Projected cost of renewable technologies and the cost-effectiveness of integrating renewables into the resource mix. As with EE and demand response, it seems likely that there will be some declining cost and increasing cost-effectiveness that may have been too modestly reflected in the IRP.
- The potential for more customer-owned generation including incipient technologies.
- Regional supply and demand considerations (including transmission) and greater coordination with the RTOs.
- Future enhancements to load forecasting, evaluation of demand-side management (DSM), the stakeholder process, databases, analytical tools, scenario construction, and all other aspects of the IRPs.

Wabash Valley Power Association's (WVPA's) IRP and IRP process has improved, particularly in its discussion of scenarios, greater attention to risk analysis, and the utilization of state-of-the-art planning tools (PLEXOS – Section 1 page 7). Perhaps, WVPA's attention to risk is due, in part, to a combination of

retirements, having to purchase new resources (page 6), making market purchases to meet reliability requirements, working with each pass-through customer to make power supply decisions based on their respective risk tolerances, and the potential for customers leaving or joining the WVPA. Regardless of the reason(s) for greater attention to risk analysis, the improvements in WVPA's IRP process are noted. It is particularly noteworthy because WVPA's corporate structure limits coordination with its members on load forecasting and demand-side management in Indiana, Illinois, and Missouri. The director agrees with WVPA that:

The IRP is a planning document that evaluates the next 20 years to assess our Members' requirements for electricity and our ability to meet that need in a reliable and competitive manner. [and that the IRP is prepared under the Indiana Utility Regulatory Commission's "Rule 7", technically 170 IAC 4-7. [page 1]

The following statement by WVPA is more in keeping with the legislative and Commission intent regarding the purpose of the IRPs:

Wabash Valley's power supply team analyzes all opportunities to improve the company's power supply portfolio while being cognizant of any regulation that may impact these sources. These opportunities may include the purchase/sale of generating assets, purchase/sale of cost-based power agreements and purchase/sale of fixed priced forward contracts. We analyze these opportunities to evaluate risk, reliability, and cost impact to our Members. While Wabash Valley has developed and maintains a detailed resource plan to serve forecasted Member load requirements, we may adjust that plan if we are able to take advantage of economic opportunities that present themselves.

The director hopes future WVPA IRPs also serve as an important element of WVPA's long-term business planning rather than merely an obligation to comply with statutory regulations; especially since WVPA is facing a significant change in its resource mix over the planning horizon, as demonstrated on page 6.

WVPA constructed five scenarios⁵ to bracket the range of risks confronting WVPA. It is clear that WVPA devoted considerable attention to improving the explanatory value of the narratives to describe the scenarios as well as the increasing its effort to treat new DSM on as comparable a basis as possible as other resources. Because it operates in both PJM and MISO, the WVPA seemed to have the best understanding of how to

⁵ The Base Case, Optimistic Economy, Pessimistic Economy, Carbon Emissions Regulation, and Pulverized Coal Resource Addition

coordinate its planning and operations with the two RTOs and integrate that into its IRPs. The enhancements are significant, but there are some questions and concerns the director would like WVPA to address.

Most of the questions and the few concerns are probably easily addressed by additional clarification. Most significantly, there are remaining questions and concerns about how the load forecast was constructed and how the EE programs were bundled, evaluated, and integrated into WVPA's IRP. Although the consideration of a variety of risk metrics was well done, a more expansive discussion of the different risk measures used in the formulation of the IRP and how they affected WVPA's analysis would be helpful to the Commission, stakeholders, and other utilities. For example, we recognize that some utilities have an objective function to minimize revenue requirements over the various scenarios and resulting portfolios. Other utilities may select a portfolio that minimizes rate increases. It also is conceivable that a utility may want to achieve a higher level of reliability in response to a perception of greater risk of having insufficient resources to meet forecasted demand. All of these, and variations of these, have legitimacy. It is therefore desirable to discuss these in the narratives for the various scenarios.

As required in the Draft Proposed Rule, there is an expectation that WVPA will build on this very good effort by making continual enhancements. To this end, additional information about how WVPA (and other Indiana utilities) intend to enhance the IRP effort would be very much appreciated. This includes working more closely on planning with MISO and PJM, the appropriate calculation and use of avoided costs, enhancements to the load forecasting efforts, ongoing efforts to integrate probabilistic analysis into the scenario analysis, and incorporating new DSM into the IRP on a comparable basis to other resources.

Load Forecasting

1. WVPA, on page 13, is commended for conducting a residential end-use survey every two years.

Approximately 68% of residential customers have central air conditioning and 9% of residential customers use a heat pump to cool their homes. A quarter of residential customers heat their homes with an electric system. Wabash Valley has conducted surveys since the early 1980s. The results are used in the load forecast as an estimate of energy conservation measures, and to develop programs that will better serve the residential customers.

The last survey was conducted in late 2014 through early 2015. In general, the results of the 2015 residential survey were comparable to the 2013 survey. However, for the 2015 survey, participants were asked additional energy related questions including one designed to gauge the level of awareness

and interest in distributed generation. About 2% of survey participants have installed some form of on-site generation and another 7% have seriously considered installing it.

Questions:

- a. **Is the survey required by the Rural Utilities Service (RUS)?**
 - b. **Would WVPA please provide greater detail on the survey instrument and process? It is not clear from WVPA’s discussion whether this was a phone survey and, if so, whether WVPA conducted any verification of the residential end uses such as age, connected load, or condition. It also is unclear whether WVPA used the survey to obtain demographic information as well. It would be beneficial if WVPA provided a discussion of how the survey information was integrated into WVPA’s load forecasting models and evaluation of EE, demand response, and customer-owned generating resources.**
2. Beginning on page 34, WVPA uses forecasts of the number of customers and usage per customer to determine residential and small commercial loads. The usage per customer is unclear. WVPA states that it uses an SAE model to produce a “base index” (page 34), that air conditioning and heating market share is accounted for by weighting weather variables by market share (page 36), that appliance and lighting efficiency were accounted for in some unexplained manner (page 37), and that heating degree days (HDDs) and cooling degree days (CDDs) were included to weather normalize (page 38). It is further stated that average use was modeled econometrically using household income, appliance market share, people per household, electricity price, and weather (page 39).

Comments:

The load forecasting discussion would benefit from elaboration and clarification. For example, the discussion of small commercial use per customer that “was modeled as a function of weather and retail sales per employee” (page 39) would benefit from a more detailed discussion. On page 34, WVPA states that it uses “Econometric and regression models...” (page 34). However, the next paragraph suggests WVPA is using a hybrid econometric/end-use residential model in an attempt to capture the benefits of both techniques. On page 34, though, WVPA says it does not employ end-use modeling.

Questions:

- a. **Would WVPA please clarify?**
- b. **Did WVPA use an SAE model?**

- b. Do we understand correctly that WVPA states the pass-through loads are not included in energy or peak managed by WVPA but are included in planning load? If this understanding is correct, please provide a discussion.**
- 6. The weather ranges (extreme and mild) are possibly too extreme to show more realistic forecast variance on page 42.

Questions:

- a. Although it is good practice to examine extremes that are relatively low risk but have significant ramifications if realized, would it have been better to have these extreme and mild ranges as separate scenarios or sensitivities and have a more modest difference around the reference case?**
 - b. Would WVPA have been better served by having several different load forecasts (perhaps four or more in addition to the reference case) and describe these different forecasts as partially attributable to weather?**
- 7. WVPA, on pages 41-42, discusses development of optimistic and pessimistic load forecasts. An econometric model of energy requirements as a function of economic activity and heating and cooling degree days was developed to generate energy requirements under optimistic economic conditions. An economic index composed of households and employment was created to represent the economy in the scenario forecasts. To generate the optimistic forecast, the optimistic case economic index forecast was compared to a base case projection. The econometric model coefficient is used to estimate the optimistic energy requirements forecast.

Comment:

The description is too cursory to understand what was done to develop alternative load forecast based on economic drivers.

Questions:

- a. How was the economic index created?**
- b. How was the index used to develop alternative load forecasts?**
- c. How was the econometric model coefficient used to estimate the optimistic energy requirements forecast?**

Question:

If WVPA agrees that the power expansion planning analysis results in a short-term overbuild, would WVPA provide a discussion of the rationale, how this happened, and what will WVPA do in future IRPs to compensate or correct for this tendency?

3. Wabash Valley states, “For the IRP, these reserve requirements of 14.3% in MISO and 15.4% in PJM are used for planning Wabash Valley’s resource requirements needed in the future.” (page 9)

Questions:

- a. **In an effort to minimize revenue requirements or the delivered price to customers, what steps, if any, does WVPA anticipate considering to reduce resource adequacy requirements?**
 - b. **Would MISO and PJM, for example, allow WVPA (or any member utility) to reduce its resource adequacy requirements if the RTOs had greater confidence in WVPA’s load forecasting, the capabilities of WVPA’s DSM programs, or WVPA’s long-term resource planning?**
4. WVPA, on page 62, said the PLEXOS model was used to evaluate each of the supply-side and demand-side resource options on an equivalent basis.

Questions and Comments:

- a. **Was EE and demand response used to modify the load forecast prior to optimization? In other words, was the PLEXOS model limited to selecting only supply-side resources in the optimization process?**
- b. **Was the co-optimization capability of PLEXOS used to simultaneously analyze all resources?**
- c. **Consistent with the IRP Draft Proposed Rule, a discussion of how WVPA intends to increase its utilization of PLEXOS and how WVPA intends to obtain enhanced data to support the full capabilities of PLEXOS would be helpful. Additionally, a good description and overview of the various PLEXOS products would be helpful. A reader also would benefit from a greater discussion of the capabilities of PLEXOS compared to how they were actually used in the IRP.**

Risk Analysis

1. The natural gas price projections (Graph 5-9 on page 76) seem high, with the base forecast over \$8/mmBtu in 2034. WVPA also uses a 100% higher price in the extreme case (>\$16/mmBtu). By comparison, EIA's AEO2015 Henry Hub base prices are \$5.69 in 2030 and \$7.85 in 2040. WVPA's highest prices are \$7.89 in 2030 and \$10.63 in 2040.

Questions:

- a. **If this is an accurate statement of the range of prices used in the IRP, did WVPA consider using other sources and lower ranges of prices?**
 - b. **Does WVPA have any concerns that the high prices, especially the extreme price, may skew the risk analysis?**
2. The methodology for the risk analysis seems to be on the right track but could be better explained.

Questions:

WVPA states it "executed" the plans "against the stochastic variables" (page 78).

- a. **Would WVPA please provide more details on how this was done?**
 - b. **It appears that each stochastic variable was analyzed separately and then some were done in combination (see Chart 5-17 on page 83). Is this an accurate characterization?**
3. With reference to Appendix F, Market Price Assumptions (page 63), which displays forward market prices for the Indiana Hub.

Questions:

- a. **How are the forward market prices developed?**
 - b. **A description in the body of the report would be helpful for those who don't have access to the confidential appendices.**
4. WVPA ran one scenario with a carbon tax at \$15.07/ton in 2022 rising to \$38.46/ton in 2034. WVPA also adjusted market energy and fuel prices to reflect the impact of higher production costs. (page 70)

Questions:

- a. **Would WVPA provide a description of how the carbon tax rate was set?**
 - b. **Also, would WVPA please provide a description of how the ramifications on market energy and fuel prices were done?**
5. The next question is in regard to the performance of expansion plans against stochastic variables. (page 78)

Questions:

- a. **Was a Monte Carlo-type process used?**
 - b. **How many stochastic draws were used to develop the scenario sensitivity impact of risk components presented in Charts 5-12, 5-13, 5-14, 5-15, and 5-16?**
6. Tornado charts are presented in Charts 5-12, 5-13, 5-14, 5-15, and 5-16.

Questions:

- a. **What other risk metrics are available from PLEXOS?**
- b. **What are the strengths and weaknesses of the alternative risk measures?**
- c. **Why was the tornado chart selected as the sole/primary risk metric to be presented?**

Energy Efficiency

1. WVPA modeled demand response and EE as a resource instead of a reduction in load (page 22) but acknowledge that the EE has been captured to the extent that it is in the historical data as mentioned on page 37.

Questions:

- a. **Is it correct to say that WVPA did not remove EE from the historical data when it estimated its load forecast models?**
 - b. **Did WVPA subsequently give effect to the EE that had been removed? Please elaborate on how EE was handled.**
2. WVPA's 2015 IRP, on page 58, states it is evaluating demand-side resource options on a comparable basis to supply-side resources.

Questions:

- a. **Are EE and demand response programs put into bundles that the resource expansion models can select when optimizing resource options?**
 - b. **If EE and demand response are not included as bundles in the optimization process, then how is comparable treatment between DSM and supply- side resources implemented?**
 - c. **If EE and demand response are put together into bundles, then how are bundles developed? What data and assumptions were used to develop the bundles?**
3. *ACES staff is responsible for the dispatch of Wabash Valley's demand response (DR) programs. Wabash Valley DR representatives inform ACES staff members of current program objectives, program parameters and information management functions. ACES utilizes the DR programs to manage costs, including high wholesale market prices, and respond to capacity shortages. (page 9)*

Questions:

- a. **Given that WVPA is in two RTOs and serves three states, would WVPA please provide the basis and rationale for how demand response is utilized?**
 - b. **That is, is demand response used to reduce WVPA's system coincident peak, the RTOs' coincident peak, or other?**
 - c. **What type of input does ACES have in determining the cost-effectiveness of demand response?**
4. For EE, WVPA obtained high-level cost estimates from a condensed study of achievable efficiency potential. (page 58)

Questions:

- a. **What does "condensed" mean in this context?**
- b. **Why has the study not been made available?**
- c. **When was the study published, and by whom was the study prepared?**
- d. **How were the cost estimates in Table 4-3 developed?**
- e. **Are the cost estimates based directly on the condensed study of achievable efficiency potential?**
- f. **If no, how were the estimates modified going from the potential study to Table 4-3?**

5. There is just a one-paragraph description of EE planning process but nothing one can understand regarding data used or how the programs were developed. (p. 60)

Questions:

- a. **How does the consultant validate program savings?**
 - b. **Does the consultant act as both the EM&V entity and the lead advisor on program development?**
 - c. **Did the consultant prepare a market potential study?**
 - d. **How was this market potential information used and modified to develop the programs included in the IRP evaluation?**
 - e. **If a market potential study was not used, then what information was used and what is the source of this information?**
 - f. **How was the technical and economic viability of the EE programs assessed?**
6. Appendix E presents information for an Expansion Energy Efficiency resource and an Expansion 1MW Demand Response resource.

Questions:

- a. **Were these resources included in the PLEXOS optimization process?**
- b. **How were the data presented for these resources developed?**
- c. **What is the source of the data? Again, more information would be helpful to better understand how demand response and EE were evaluated.**

Avoided Costs

1. Request for clarification regarding WVPA's discussion of avoided costs estimation and usage in the IRPs. (page 61)

Questions:

- a. **How is "the cost of network transmission to deliver the capacity to the distribution points of Wabash Valley's Members" developed or estimated?**
- b. **How is avoided cost used in the IRP process? Are avoided costs of transmission used in the IRP process?**

- c. **How does the avoided energy costs in Table 4-4 differ from the market price assumptions presented in Appendix F?**
- d. **Should they differ conceptually?**
- e. **How are they each used in the IRP analysis?**
- f. **Are the avoided costs in Table 4-4 used to screen DSM measures prior to being included in bundles?**

Summary

WVPA's 2015 IRP represents an improvement over prior IRPs as required by the Draft Proposed Rule. In particular, the director commends WVPA for improved discussion of scenarios, greater attention to risk analysis, and the utilization of state-of-the-art planning tools. The graphic representations were also very good and contributed to the readability of the IRP.

Given the significant changes in WVPA's resource mix and the changing composition of resources in MISO and PJM and the Eastern Interconnection, the director trusts WVPA will continue to make efforts to interject risk analysis into all aspects of the IRP from the development of load forecasts to the modeling and evaluation of a wide range of scenarios. Although the narratives related to the scenarios were improved from prior IRPs, future IRPs would benefit from elaboration and greater clarity. Again, consistent with the Draft Proposed Rule, the director would welcome greater discussion of potential enhancements to all phases of the IRP process, including expanded discussions of the load forecasting methodology; integration of enhanced data into the load forecasts; and the evaluation of EE, demand response, and the potential ramifications arising from increasing penetration of customer-owned resources.

¹ *In 2016, Wabash Valley plans to retire the steam turbine at Wabash River Unit 1 and convert the combustion turbine at Wabash River Unit 8. Wabash Valley also plans to place a 6.4 MW landfill gas plant in-service in 2016. To supplement these activities in 2016, Wabash Valley's base expansion plan shows that we need to add approximately 100 MW of baseload combined cycle and 150 MW of peaking combustion turbine resources. In January 2016, Wabash Valley petitioned the Indiana Utility Regulatory Commission (IURC) for an issuance of a Certificate of Public Convenience and Necessity to purchase and own an existing baseload coal resource totaling approximately 83 MW. We believe this acquisition will be an effective long term low cost hedge for our Members. However, we decided not to include this 83 MW resource within this IRP since the necessary approvals to complete this transaction are ongoing at the time of this IRP filing.*

To round out Wabash Valley's 2016-2018 three year plan, our base expansion plan indicates we need to add another 100 MW of baseload combined cycle in 2018 to partially replace capacity and energy lost when a unit contingent power purchase agreement expires at the end of 2017. In addition, Wabash Valley plans to purchase 25 MW of wind power from

an Indiana wind project that is expected to begin commercial operation in the first quarter of 2018 and construct a 3.2 MW landfill gas plant in 2018.

Also, throughout the three year period, Wabash Valley plans to save up to 14 MW of capacity through our EE programs. Although our optimization model did not choose our DR programs in the early years of our 20 year plan horizon, Wabash Valley may choose to continue to build DR resources in the near term. Wabash Valley will continually evaluate available projects that are expected to provide cost effective renewable energy and seek alliances, partnerships and opportunities for joint operations with other electric utilities. [pages 6-7]