

INDIANA UTILITY REGULATORY COMMISSION

**ELECTRICITY DIRECTOR'S
FINAL REPORT**

**2015 - 2016 INTEGRATED RESOURCE PLANS SUBMITTED BY
DUKE ENERGY, INDIANA MICHIGAN, INDIANA MUNICIPAL POWER AGENCY,
AND WABASH VALLEY POWER ASSOCIATION**

Date of the Report: August 30, 2016

ELECTRICITY DIRECTOR'S FINAL REPORT

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**INTRODUCTION TO THE FINAL DIRECTOR'S REPORT
FOR 2015-2016 INTEGRATED RESOURCE PLANS
Issued August 30, 2016**

A. INTRODUCTION AND BACKGROUND

With the passage of P.L. 246-2015 (SEA 412-2015) on May 6, 2015, Indiana law now explicitly requires long-term resource planning for the State of Indiana. For the Integrated Resource Plans (IRPs) submitted on or after Nov. 1, 2012, the utilities voluntarily adhered to the Draft Proposed Rule (Proposed Rule) to modify 170 IAC 4-7 Guidelines for Electric Utility Integrated Resource Plans (RM 11-07). The Indiana Utility Regulatory Commission (Commission), utilities, and stakeholders collaboratively developed the Proposed Rule, which is available on the Commission's website at <http://www.in.gov/iurc/2674.htm>.

Four Indiana utilities submitted their IRPs on Nov. 1, 2015. Links to the IRPs can be found at http://www.in.gov/iurc/files/2015_to_16_IRP_DRAFT_REPORT_MAY_20_2016.pdf. Links to the utilities' comments regarding the Director's Draft Report and other stakeholders' comments are included here. Please note that these are the public versions of the IRPs and do not include confidential information and most appendices:

1. Duke Energy Indiana (DEI)

http://www.in.gov/iurc/files/DUKE_Reply_Comments_to_Directors_Draft_2015_IRP_6_20_2016.pdf

2. Indiana Michigan Power Company (I&M)

http://www.in.gov/iurc/files/I_and_M_Reply_Comments_to_Directors_Draft_2015_IRP_6_20_2016.pdf

3. Indiana Municipal Power Agency (IMPA)

http://www.in.gov/iurc/files/IMPA_Reply_Comments_to_Directors_Draft_2015_IRP_6_20_2016.pdf

4. Wabash Valley Power Association (WVPA)

http://www.in.gov/iurc/files/WVPA_Reply_Comments_to_Directors_Draft_2015_IRP_6_20_2016.pdf

Written comments regarding the IRPs and the Director's Draft Report also were submitted by various entities, including Citizens Action Coalition, Earthjustice, Indiana Distributed Energy Alliance, Michael A. Mullett, Sierra Club, and Valley Watch, referred to as Joint Commenters. These comments can be found at

http://www.in.gov/iurc/files/JOINT_COMMENTERS_Reply_Comments_to_Directors_Draft_2015_IRP_6_20_2016.pdf.

Section 2 (h) of the Proposed Rule requires the Director to issue a Draft Report on the IRPs no later than 120 days from the date a utility submits an IRP to the Commission. Section 2(k) of the Proposed Rule limits the Director's Draft Report and Final Report to the informational, procedural, and methodological requirements of the rule, and Section 2(l) of the Proposed Rule restricts the Director from commenting on the utility's preferred resource plan or any resource action chosen by the utility.

THE IMPORTANCE OF THE IRP PROCESS

Although businesses dedicate varying degrees of effort to forecasting demand for their products and planning to meet their customers' needs, few industries are as important as the electric system, which has been called the most complex manmade system in the world. Because of the critical importance of the industry, state-of-the-art planning processes are essential. The need for continual and immediate improvements is heightened by the risks resulting from significant changes due to aging infrastructure, increasingly rigorous environmental regulation, substantially reduced costs of natural gas, a potential paradigm change resulting in long-term low load growth, declining costs of renewable resources, and technologies including combined heat and power. The Proposed Rule anticipates continual improvements in all facets of the planning processes of Indiana utilities. The Director recognizes that DEI, I&M, IMPA, and WVPA place great reliance on their IRPs as being integral to their business planning. Utilities have made substantial progress in enhancing the credibility, clarity, and all technical aspects of their IRPs. However, given the increasing risks and their attendant financial risks, there is a need for continued improvements.

PRIMARY ISSUES IN THE IRP PROCESS—GENERAL COMMENTS

The Final Report primarily focuses on the importance and need for continued improvement in load forecasting, demand-side management (DSM), and integration of DSM into the load forecast because these were common areas of concern and interest among all four utilities. The focus on these three areas should not be construed as suggesting that the Director is not interested in continuing improvements in risk analysis in IRPs, the need for continuing enhancements to the stakeholder process, continued efforts to integrate renewable and customer-owned resources into the IRPs, mutually beneficial interactions with the regional transmission organizations' (RTOs') long-term planning as it affects the utilities' IRPs, improvements to databases, and continued development of state-of-the-art planning tools. To a large extent, all four of the utilities made substantial improvements in these areas.

COMMITMENTS TO CONTINUAL IMPROVEMENTS

DEI, I&M, IMPA, and WVPA all have committed to continual improvements in the development of more easily understandable and internally consistent narratives for all aspects of the IRP. Although the Director does not intend to be prescriptive in the form of the IRPs, it is imperative that utilities write for both a lay audience and an expert audience. Meeting these two different and disparate objectives is a difficult but essential undertaking. The utilities should consider stakeholder input to provide one means of evaluating drafts of the report. In addition to a concise executive summary, the primary effort to educate a wider audience should include concise narratives, easy-to-understand graphics, and understandable examples. It may be that more in-depth analysis of subject matters could be contained in appendices. Utilities, as part of their articulation of potential continual improvements, might use this as an opportunity to expound on specific approaches, innovative ideas, the efficacy of software, the development of enhanced databases, and how the Commission might be of assistance.

All Indiana electric utilities are commended for making a concerted effort to improve stakeholder understanding and active participation. To this end, the utilities conducted a primer on Integrated Resource Planning. For specific stakeholder processes, the top management and technical staff of I&M was particularly actively engaged. DEI's technical staff was very engaged.

The Director is appreciative to the utilities and stakeholders that participated in the process, particularly those that offered comments. With the longer IRP cycles, the Director hopes there will

be greater opportunity to explore difficult issues more thoroughly and to have more meaningful input into the development of databases, assumptions, scenarios, sensitivities, and analysis of the various portfolios. Based on the helpful clarifications and constructive criticisms, the Director intends to have more dialogue with utilities and stakeholders throughout the process.

B. COMMENTS ON EACH UTILITY’S INTEGRATED RESOURCE PLAN

1. DEI’S INTEGRATED RESOURCE PLAN AND PLANNING PROCESS

This Final Director’s Report reflects the following issues and emphasizes those that the Director regards as important concerns. Because of the significant improvements in risk analysis and other aspects of the IRP, combined with uncertainties about the Clean Power Plan (CPP), this report does not address all the questions and concerns raised by the Director or stakeholders in the Draft Director’s Report. The issues are:

- Load forecasting
- Demand Side Management (DSM)
- Relationship between load forecasting and DSM

DEI’s written response to the Draft Report and subsequent meeting with technical staff was helpful and informative. The Director notes the questions contained in the three topic headings are intended to stimulate further thought and discussion rather than promoting or advocating specific methodologies. The intent of the Director’s Report is to challenge processes, analysis, and tools if they might be done better, not just be done differently. Many, if not most, of the issues addressed throughout this report are quite new, and our collective knowledge and experience are too limited to make definitive recommendations at this time.

At the outset, the Director recognizes that IRPs provide a snapshot of optimal resource development based on current information and assumptions. Noting that the primary drivers of resource decisions are dynamic, the Director recognizes that DEI used this IRP as part of their business plan to objectively assess retirements and additions to the resource mix as well as their DSM filings, which is a primary purpose of the IRPs.

DEI has undertaken an innovative stakeholder process. The uncertainties, particularly regarding the status of the CPP, afforded DEI an opportunity to experiment with the stakeholder process. DEI was able to gain broad acceptance of the portfolios and then constructed scenarios and sensitivities to evaluate those portfolios. Although this is in contrast to the normal practice of constructing scenarios and sensitivities and allowing the long-term planning models to develop optimized (based on the underlying assumptions) resource portfolios, DEI’s *reverse engineering* of selecting the portfolios first and deriving the scenarios to support the portfolios provided useful insights. Having served the purpose of confidence building between DEI and stakeholders, for DEI’s next IRP in the 2018 – 2019 cycle, the Director anticipates DEI will use a more conventional approach to long-term resource planning for DEI’s 2018-2019 cycle.

The IRP stakeholder process also served an important purpose of confirming that DEI and its stakeholders share many common goals in the consideration of long-term resources. The recognition of shared goals should give all Indiana utilities confidence that they can find common ground on important issues of reliability, cost of delivering power, and meeting environmental requirements in a rapidly changing electric industry.

DEI also made significant improvements in their IRP analysis. During the stakeholder meetings, DEI recognized the increasing risks associated with dramatic changes in the resource mix throughout the region and Eastern Interconnection. This places added emphasis on the need to inform its resource planning analysis with information from the Midcontinent Independent System Operator (MISO), especially if the CPP is upheld by the Supreme Court. Assessing the potential ramifications of various risks make the development of a broad range of scenarios and sensitivities more important to better assess potential risks of achieving reliability metrics and avoiding a higher cost of delivering electricity. These various risk factors include the following:

- Future wholesale power prices for coal-fired generation
- The projections for low-cost natural gas
- The decreasing cost and increasing efficiency of renewable resources
- Technological changes for DSM that make this resource more cost effective
- Increasing potential for customer-owned generation
- Small increases in (or perhaps even declining) load growth
- Increasing capital costs of traditional coal-fired and nuclear generating resources
- Increasingly stringent environmental policies

To this end, DEI's IRP had improved narratives to describe alternative futures associated with each scenario. In addition, DEI employed state-of-the-art analytical tools that add credibility to the IRP analysis, and their efforts to treat DSM comparably to other possible resources is commendable.

The Director also appreciates Scott Park, Melanie Price, Dick Stevie, Phil Stillman, and Tom Wiles meeting with the Commission's IRP staff to clarify questions and address concerns expressed in the Draft Director's Report. The Director's intent is that the comments in this Final Report reflect the improved understandings from this meeting. Among those understandings is that DEI is committed to continual improvements in describing the scenarios, sensitivities, assumptions, and methods such as the construction of DSM bundles and the treatment of DSM on as comparable a basis as is reasonably feasible to other resources.

DEI's offer to share the modeling results with stakeholders; as long as this does not interfere with the IRP's timely completion is appreciated. With the three-year cycle in the new Draft Proposed IRP Rule, it is hopeful that this will afford more opportunity for stakeholders to have meaningful input from the inception of the IRP through the preparation of the submittal of the IRP.

The Director acknowledges the time commitment involved in the stakeholder process by DEI's technical staff. In prior years, Doug Essaman attended the sessions, which gave the stakeholder process gravitas by confirming its importance to DEI. Hopefully, the level of commitment to a useful, credible, and robust IRP will continue.

Load Forecasting

DEI's Load Forecasting

DEI uses ITRON's Statistically Adjusted End Use (SAE) model for residential and commercial forecasts. The basic industrial forecast econometric model structure is largely unchanged from prior years. However, DEI replaced Regional Manufacturing GDP with the Industrial Production Index. In addition to industrial production, employment and the effect of electricity prices also are primary drivers.

The Director's Draft Report

The Draft Director's Report asked DEI to discuss the rationale for some changes in the load forecasting model's specifications to discuss how weather normalization was done, explain the calculations for coincident peak demand, specify whether DEI plans to enhance their load research database and increase reliance on DEI- and Indiana-specific data, and specify whether DEI is considering enhancements to their commercial and industrial forecasts.

DEI's Reply Comments

DEI, in their response to the Draft Director's Report, explained the rationale for changes in the load forecast for each type of customer. DEI, on an ongoing effort, planned to enhance the credibility of their weather normalization to a 30-year history and increase their use of Indiana-specific data, including enhanced use of DEI-specific load research.

The Director's Response

DEI and its stakeholders recognize that the load forecast is the foundation of the IRP process. The ramifications of over- or under-forecasting customers' long-term electricity needs pose a significant financial and reliability risk to DEI and its customers. Because of its primacy in the planning process, the Director and the Citizens Action Coalition (CAC), et al. devoted considerable attention to DEI's load forecasting processes, analytical tools, and methodology.

Based on the information provided by DEI in their reply comments and in conversation, the Director believes that DEI's load forecast methodologies, analytical tools, and processes are reasonable. Of course, as with all aspects of the IRP, it is anticipated that there will be ongoing scrutiny of forecasting methods and data. For example, the Director expressed concerns about too much reliance on intelligence gained from conversations with the large account representatives or quarterly earnings calls (page 22 of DEI's response). The information gained from these sources has value, but it may be primarily short term. As DEI noted, industrial customers have a relatively short planning horizon. Also, industrial customers might not be comfortable or even legally able to share long-term information about their operational and production plans.

As evidenced by changes DEI has made to the forecasting models, it is clear that DEI is committed to continual improvement. DEI agreed that increased data from AMI and Smart Grid will enhance the forecasting and DSM databases (page 21 of DEI's response). For purposes of more robust risk analysis, DEI also committed to "exploring high and low load grow scenarios or sensitivities when making resource decisions...in its next IRP" (page 19 of DEI's response).

DEI's Demand-Side Management

DEI's DSM Analysis

DEI created two types of energy-efficiency (EE) bundles. A base bundle was modeled to reflect the general level of savings and aggregate performance characteristics similar to the 2015 programs and those proposed for the 2016 – 2018 period. DEI also created an incremental DSM bundle with characteristics identical to the base bundle except higher cost because they are trying to increase customer participation. DEI's optimization model always selected the base bundle and at times augmented the base bundle with an incremental bundle. In sum, the optimization model could choose more DSM than the base bundle, but it did so only on a limited basis based on cost effectiveness.

The bundles reflected general measure characteristics and load shape, and this information was included in the optimization process rather than any specific measures.

The Director's Draft Report

The Director and CAC et al. asked for elaboration on whether the DSM bundles might be more discrete to take better advantage of one of the inherent benefits of DSM relative to traditional resources. The Director also asked for DEI's thoughts on whether sub-hourly demand data might provide valuable insights that could appropriately affect the comparisons with other resources.

DEI's Reply Comments

With regard to the construction of DSM bundles, DEI said, "Simultaneous optimization did occur in the modeling because the IRP model was given the opportunity to select from multiple bundles of EE (page 6 of DEI's response). DEI notes that incremental DSM has an opportunity to be selected by the planning model without being tied to specific measures (page 8 of DEI's response). Because simultaneous optimization was conducted for DSM and all resources, the results were not hardwired. DEI also noted, "The Economic Potential DSM from the Market Potential Study was used as an upper limit to the overall size of all of the Base and Incremental Bundles combined which was not reached by any of the IRP scenarios." DEI did not "start with the overall Technical Potential and work backwards, but rather to start with a well-known set of programs and build upwards" (page 9 of DEI's response). That is, in advance of resource optimization, no DSM was screened out.

Based on the IRP and DEI's written and verbal responses, the Director understands that DEI pre-screens measures for the same end use to use the most cost-effective measures and bundles them based on the initial expected cost and avoided costs. The first base DSM bundle was based on a combination of the 2015 approved portfolio, the 2016 – 2018 proposed portfolio, and an expectation that the EE programs in 2019 and beyond would provide the same level of EE impacts as 2018. This initial portfolio was evaluated for cost effectiveness but was only the starting point for the creation of a set of EE bundles to be evaluated in the IRP. No pre-screening was performed to eliminate programs. In fact, no cost-effectiveness testing was performed on any of the other nine DSM bundles prior to being analyzed in the IRP model. Tom Wiles and Dick Stevie discussed how DEI analyzed EE. Dick Stevie provided an analysis of the process. This additional clarification was helpful, and it might be of interest to other Indiana utilities. Recognizing there is no consensus on the right way to analyze EE, this approach may serve as useful discussion for further enhancements of the analysis of EE.

The Director's Response

The Director understands from the written response as well as from conversations with DEI's technical staff that DEI initially developed bundles that were screened based on their familiarity with the expected cost of individual DSM programs. DEI states the DSM measures were subjected to analysis by "DSMore" (a DSM planning model) which "requir[es] imputing information regarding the energy efficiency measure or program to be analyzed, as well as the program cost, avoided costs, and rate information of the utility" (page 14 of DEI's response). The System Optimizer (the long-term planning model) was allowed to select base and incremental DSM bundles based on their costs and load shape ramifications on the same basis as any other resource.

The construction of DSM bundles, the "roll off" of DSM effects from the load forecast, and the treatment of EE on as comparable a basis as is reasonably feasible seemed to be well regarded by

the CAC and other stakeholders during the stakeholder meetings. However, from questions and concerns raised by the Director and CAC, these topics remain a matter of continued interest and questions. DEI's written response to the Draft IRP Report, the CAC's comments, and our subsequent meeting with DEI clarified how EE was modeled. In recognition of this ongoing interest, DEI committed to a more detailed discussion of these topics in future IRPs.

The Director is pleased that DEI intends to investigate improvements for future IRP analysis, including modeling the incremental DSM bundles with more granularity related to individual programs and potentially shortening the operating period of each bundle (page 14 of DEI's response). With increased deployment of advanced metering infrastructure (AMI), DEI recognizes that increased granularity of data (e.g., sub-hourly load data) would be a further refinement to future IRPs (page 20 of DEI's response). This level of usage detail, especially when combined with appliance/end-use data and demographics, would give appropriate advantage in the resource modeling to smaller amounts of DSM compared to natural gas peaking generation and, certainly, other relatively large ("lumpy") generating resources that have higher minimum capacities.

Relationship between Load Forecasting and DSM

DEI's Load Forecasting and DSM Integration

Scott Park, Dick Stevie, Phil Stillman, and Tom Wiles provided a good clarification of how EE was integrated into DEI's load forecasting. DEI's load forecast includes the EE forecast that is based on the expected implementation of the portfolio proposed in Cause No. 43955 DSM-3 and assumptions for incremental EE that is contained in DEI's proposed portfolio (page 23 of DEI's IRP; also see the table on page 78 of DEI's IRP). DEI stated that, based on "stakeholder and Commission staff recommendations, EE was modeled as a supply-side resource. This is particularly challenging due to the way EE is included in the load forecasting process, the uncertainty of EE forecasting, and combining EE programs into a bundle that can be modeled with supply side resources like natural gas fired combined cycle or solar resources" (page 9 of DEI's IRP).

The Director's Draft Report

Because of the complexities of accounting for the effect of EE on the load forecast, most of the questions regarding the DSM-load forecasting relationship were about the potential for double-counting some EE, under-counting some EE, and the effects of EE on load shapes. In an effort to obtain clarification, the Director asked DEI several questions and requested more detail on how EE is "rolled off" (sometimes referred to "degraded" due diminished effects) of the load forecast so that the amount of EE is more accurately presented in the load forecast.

DEI's Reply Comments

DEI integrates DSMore with the Statistically Adjusted End-Use Model. DEI states, "DSMore outputs an hourly savings profile for each measure that is aggregated across all of the DSM programs and this hourly savings profile is provided to the Load forecasting and IRP group for the purpose of modeling DSM savings on an equivalent basis to other resources" (page 13 of DEI's response). DEI said accelerated benefits (i.e., usage reductions that would not have occurred for some time absent the utility's promotion) and "naturally occurring energy reductions" (from Energy Information Administration [EIA] data for the West North Central Region), "roll off" and "roll on." DEI provided a helpful example of roll-off. Specifically, assume a seven-year average measure of life for 100 MWh. These savings are rolled off in years five through nine as the naturally occurring

efficiencies are expected to roll on by means of incorporating the naturally occurring efficiencies in the end use models (i.e., SAE and the load forecast).

Director's Response

DEI's clarifications were helpful and answered questions raised by the Director and possibly the questions and concerns raised by the CAC et al. DEI said they were committed to ongoing improvements in evaluating DSM and its integration into the load forecasting process. In addition to ongoing review of the treatment of DSM, DEI agreed that increased data from AMI and Smart Grid will, overtime, enhance the forecasting and DSM databases (page 21 of DEI's response).

DEI's integration of DSM into their load forecasts appears well reasoned. However, the Director urges DEI and all Indiana utilities to provide a detailed and, to the extent possible, understandable, comprehensible discussion of the process for the treatment of EE within the load forecasts. The Director hopes DEI will make continued improvements to the quality, quantity (sub-hourly), and granularity of its databases used to evaluate DSM and to develop DEI's load forecasts. Improved data will make more effective use of DEI's modeling tools and, as a result, improve the quality of the analysis and enhance the credibility of all aspects of the IRP.

Summary and Conclusions

DEI's significant improvements in the 2015 – 2016 IRP and the commitment to continuing improvements are consistent with the Draft Proposed Rule and are very much appreciated. Without being prescriptive on the formatting of future IRPs, we hope DEI and other Indiana utilities will further address lay audiences as well as those who have varying degrees of expertise. This is a difficult undertaking. One potential strategy would be to have a somewhat less technical version with illustrations as footnotes or endnotes and technical appendices that address specific topic areas with both a more general and a more detailed technical discussion.

Among several commitments, "DEI agrees additional Stakeholder involvement in future IRP processes might improve the understanding of the assumptions and treatment of EE as a resource and this recommendation will be incorporated into the future IRP stakeholder process" (page 5 of DEI's response). More broadly, with the longer IRP planning cycles, stakeholders can provide greater meaningful input into improved narratives for the portfolios, scenarios, and sensitivities. DEI continues to evaluate the load forecasting methods, model specifications, and opportunities to enhance the databases.

The Director acknowledges that DEI used this IRP as part of their own business analysis and the IRP stakeholder process to build confidence that stakeholders and DEI share many fundamental objectives. Especially given the uncertainty of natural gas costs, dynamic changes in the market value of coal-fired generating units in the MISO facilitated markets, the costs of renewable technologies, innovation in DSM, the potential for customer-owned generation, the CPP, and the potential ramifications of other environmental rules, this IRP was an appropriate time for DEI to concentrate on the future composition of its resource mix. However, the Director trusts that future IRPs will be more expansive beyond the three (or four) scenarios that were optimized in this IRP. Because of the uncertainties mentioned previously, though, this year's IRP provides a foundation for DEI's future IRPs.

If, for example, the CPP survives legal challenges, DEI and other utilities may have additional information available to conduct a more in-depth analysis of potential risks associated with the CPP in future IRPs. Regardless, future IRPs need to consider a broad range of scenarios and sensitivities to enable DEI and stakeholders to better consider all resources and their attendant risks.

With the risk factors previously discussed and the potential benefits of broad regional action such as compliance with the CPP and to mitigate adverse ramifications of a changing regional resource mix, the Director is pleased that DEI recognizes the need to inform their IRP with the long-term resource planning of MISO (page 263 of DEI's response; see also pages 22, 40, 86, 93, 267 – 8, and 271 of DEI's IRP). Future IRPs seem certain to address concerns about the profitability of coal-fired generation, the integration of additional renewable resources, and issues that are unexpected.

2. I&M's INTEGRATED RESOURCE PLAN AND PLANNING PROCESS

This Final Director's Report reflects the following issues and emphasizes those that the Director regards as important concerns. This report does not address all the questions and concerns raised by the Director or stakeholders in the Draft Director's Report. The issues addressed are

- Load forecasting
- Demand Side Management (DSM)
- Relationship between load forecasting and DSM

I&M's written response to the Draft Report and subsequent conference call was helpful and informative. The Director notes the questions contained in the three topic headings are intended to stimulate further thought and discussion rather than promoting or advocating specific methodologies. The intent of the Director's Report is to challenge processes, analysis, and tools, and to gauge whether they might be done better, not just be done differently. Many, if not most, of the issues we address throughout this report are quite new and vexing for the industry, and we do not wish to make definitive recommendations until we have gained further experience with the new issues.

The Director recognizes the benefit of I&M using this IRP as part of their business plan to better examine the viability of the Rockport units over the 20-year planning horizon. The decision to retain or retire one or more of the Rockport units may be the most important resource decision I&M will have to address. The Director also commends I&M for significant analytical and process improvements in this IRP as well as I&M's commitment to continual enhancements to their IRP stakeholder processes, development of scenarios and sensitivities with improved narratives, the use of state-of-the-art analytical tools such as PLEXOS, improved methodologies to treat DSM on as comparable a basis as possible to other resources, and I&M-specific databases. Specifically, I&M

- Recognizes opportunities for greater stakeholder involvement in the development of assumptions, scenarios, sensitivities, and data sources as a result of moving from a two-year to three-year IRP cycle;
- Stated their commitment to improving the narratives that tell an internally consistent and well-reasoned story;
- Expressed a willingness to improve the discussion of complex planning issues and methods such as:
 - (a) the efforts to treat DSM on as equal a basis as possible to other resources;
 - (b) allowing the long-term planning model to select the optimal array of resources based on objective assumptions and data; and
 - (c) consider methods for giving effect to calculating Transmission & Distribution (T&D) related costs that might affect the cost-effectiveness of DSM or other non-utility owned resources (page 26 of I&M's response).
- Will review alternative programs to enhance their load research database with sub-hourly demand information that will improve I&M's DSM analysis and add credibility to I&M's load forecasting (page 7 of I&M's response).
- Will work with stakeholders, the Commission's IRP staff, and others to examine other risk metrics that might be useful in evaluating future IRPs (page 23 of I&M's response).

Load Forecasting

I&M's Load Forecasting

For residential and commercial load forecasting, I&M uses a blended short-term Auto-Regressive Integrated Moving Average (ARIMA) model as something of a sanity check to ITRON's Statistically Adjusted End-Use (SAE) model for longer-term load forecasting. Professional judgement is used to resolve differences—if any—between the two models. For industrial load forecasts, I&M relies heavily on customer service engineers who are assigned to specific industrial clients to augment ARIMA and econometric methods. Historically, I&M models 10 of the larger industrial customers in Indiana and 10 in Michigan. I&M supplements this information with market intelligence data from Moody's Analytics.

The Director's Draft Report

The Director asked clarifying questions about the integration of the SAE and the ARIMA forecasting methods. The Director noted the importance of large customers—and the attendant risks—and asked whether I&M placed undue reliance on customer service engineers to prepare industrial forecasts. The Director also expressed concern that I&M may be too reliant on the experience of industries served by other AEP companies to construct high and low load forecasts and may not place as much reliance on independent market forecasts or other forecasting methods. The Director also asked I&M what enhancements I&M was considering for future IRPs, including enhanced databases.

With regard to databases, the Director noted that I&M uses a Residential Customer Survey to supplement information from the Energy Information Administration (EIA) for use in the SAE Model. However, there was no comparable survey for commercial and industrial customers (page 25 of I&M's IRP).

I&M's Reply Comments

In response to the Director's question regarding the blending of the SAE with the ARIMA forecasts, I&M explained that the short-term models were used as something of a sanity check on the SAE models to better capture short-term forecast volatility (pages 4 and 6 of I&M's response). "Even though the long-term models were ultimately selected, the short-term forecasts still play a vital role in evaluating whether or not the final forecast is reasonable and makes sense, especially with regard to the monthly variations. By comparing the model results from the two independent forecast methodologies, we are leveraging the strengths of both models to provide a better understanding of the key drivers" (page 4 of I&M's response).

In clarification discussions with I&M, I&M committed to provide a narrative in future IRPs to explain any professional judgement adjustments from the ARIMA Model to the long-term model in future IRPs.

With regard to the lack of a commercial and industrial end-use survey, I&M contended that the commercial and industrial classes were too heterogeneous and would be costly and difficult to conduct. As a default, I&M relies on the SAE model with EIA data. (page 7 of I&M's response)

The Director's Response

I&M recognizes that the load forecast is the foundation of the IRP process. The ramifications of over- or under-forecasting customers' long-term electric demand pose a significant financial and

reliability risk. Because of its primacy in the planning process, the Director devoted considerable attention to I&M's load forecasting processes, analytical tools, and methodology.

The blended approach has merit but as I&M recognized, additional discussion of how the short-term and long-term models are integrated would be useful for future IRPs. I&M has committed to reduce reliance on information from other AEP-East utilities. Although the use of some—perhaps all—information may be effective, it seems appropriate to rely more heavily on I&M-specific data in part due to different regulatory structures and circumstances (page 11 of I&M's response).

Based on the information provided by I&M in their reply comments and in conversation, the Director believes that I&M's load forecast methodologies, analytical tools, databases, and processes are reasonable. However, these are always areas for continued improvement.

To I&M's credit, they recognized that technologies such as Smart Grid and Advanced Metering Infrastructure (AMI) would provide enormous data for load forecasting and DSM analysis. I&M states, "an expansion of AMI was not considered within the context of this IRP. I&M recognizes that sub-hourly data may help inform the load forecasting process relied upon in IRP modeling, especially in DR [Demand Response] applications" (page 7 of I&M's response). In addition to more discrete time intervals for metering residential customer usage, I&M recognizes the value of supplementing this load data with appliance/end-use surveys for residential customers. Similarly, the Director urges I&M to use more granular metered load data in concert with selected commercial surveys on specific types/groups of commercial customers to provide a more comprehensive assessment of their current and potential consumption patterns. To some extent, both load data and detailed end-use surveys could be done in coordination with other utilities to supplement I&M's load research. For example, there may be commonalities among different types of stores (e.g., North American Industry Classification System) to make reasonable statistical inferences based on usage and selected commercial surveys to obtain end-use information.

I&M's DSM

I&M's DSM Analysis

I&M relied extensively on Electric Power Research Institute's (EPRI's) "2014 U.S. Energy Efficiency Potential Through 2035" report to perform its analysis of DSM in the IRP. Each EE measure initially was screened based on cost compared to other measures that addressed the same end use. Higher cost measures were omitted. The judgement of DSM/EE program administrators also eliminated measures that were deemed impractical or were not popular with I&M's customers. Next, the remaining measures were included in bundles that were then analyzed in the IRP analysis on a reasonably comparable basis as other resources.

I&M did not include industrial DSM due to state law that allows industrial customers to opt out of utility-sponsored DSM programs and the belief that industrial customers, "by and large, self-invest in EE based on unique economic merit irrespective of the existence of utility-sponsored programs" (page 12 of I&M's response). Naturally occurring DSM is accounted for in the industrial load forecast.

The Director's Draft Report

The construction of DSM bundles is difficult. There is no unambiguously correct way to form bundles. As such, the Director had several questions about how I&M evaluated DSM measures and

constructed bundles. Questions about the potential for double-counting new utility-sponsored DSM with existing and naturally occurring DSM were posed.

I&M's Reply Comments

I&M noted that, in the spring of 2016, they completed a Market Potential Study (MPS). Unfortunately, this was not available for this IRP, although it will be used in future IRPs.

Based on the IRP and I&M's written and verbal responses, the Director understands that I&M pre-screens DSM measures to create bundles based on initial measure cost and avoided costs. High-cost measures were removed from consideration for inclusion in the final bundles. Measures were then reviewed with I&M's DSM/EE program coordinators to eliminate any that were thought to be impractical to implement or previously had not been embraced by customers. The remaining bundles are associated with specific load shapes and their cost-effectiveness is refined in the PLEXOS model. The PLEXOS model was allowed to select the optimal level of EE bundles (page 16 of I&M's response).

I&M said it avoids double-counting of EE, degrades the Commission-approved DSM programs, and subtracts the amount from the initial sales forecast to account for the effect of the DSM programs.

The Director's Response

The treatment of EE on as comparable a basis as is reasonably feasible was a matter of concern for the CAC et al. and all other stakeholders, the Commission's IRP staff, and I&M. I&M and Duke Energy Indiana (DEI) offer methods that appear to have both similarities and differences. Both I&M and DEI pre-screened and eliminated some measures from further consideration. The details of how the bundles were created after the measures were screened probably differ, but it appears many similarities exist. Again, the Director makes no judgment as to one method being superior to another. For example, DEI has greater reliance on Indiana-specific data compared to I&M's heavy reliance on EPRI data.

I&M said (page 12 of I&M's response) that they did not rely on specific technical or research-related literature to substantiate the belief that industrial customers will undertake investments in EE that are cost effective. Although the Director admits that some industries—maybe the most energy-intensive industries—might capture all cost-effective DSM, without empirical studies based on end-use analysis, it is difficult to assess this assertion. The utilities' planning horizon might be longer, which can make more DSM attractive to both the utility and the industrial customer. In addition, firms face capital budget limitations that can hinder investment in all cost-effective EE. Moreover, because industrial customers provide an important revenue source but with considerable risk, additional analysis into the reasonableness of this assertion would seem warranted—especially if there are major effects on I&M's resource mix or if the additional DSM would be beneficial for future environmental compliance.

I&M did set DSM programs through 2017 and allowed the IRP model to select incremental EE programs only beginning in 2018. The decision to allow the model to select incremental EE programs beginning in 2018 shows that I&M could not know what the new modeling approach would produce until after the IRP was prepared. It takes time to plan, design, and gain approval of a DSM/EE plan based on the new modeling approach. Therefore, 2016 and 2017 were treated as transition years. In contrast, DEI set a base bundle in 2016 – 2018 that reflected already approved and proposed programs but did allow the model to choose incremental bundles. The model rarely

selected these incremental bundles. To be clear, the Director takes no position on whether this treatment represents best practice, but I&M's approach appears to be reasonable. For future IRPs, the Director urges I&M, and all Indiana utilities, to continually reassess their methodology and prepare a sufficiently detailed and—to the extent possible—basic discussion of the methods to assist all those involved with IRPs to better understand the methodologies, data, and assumptions on which the analysis is based.

As noted previously, I&M expressed their commitment to examine potential improvements in the DSM analysis. This includes tailoring the DSM analysis to I&M's service territory, reducing reliance on the EPRI and the Energy Information Administration (EIA) (see pages 25 and 26 of I&M's response for examples), and enhancing their load research program by using sub-hourly load data. I&M states they are “reviewing alternative programs that can yield sub-hourly data in a cost-effective manner from larger customer (participant) base where the impacts from these programs can be modeled within a future IRP” (pages 7 and 8 of I&M's response). In reply comments, I&M also noted that in 2016 it completed a DSM market potential study of both its Indiana and Michigan service territories. I&M states the MPS will be a basis to update and align I&M EE data in future IRPs.

Relationship between Load Forecasting and DSM

I&M's Load Forecasting and DSM Integration

The foundation for the load forecasting and DSM analysis is the Statistically Adjusted End Use Model. I&M's forecast attempts to capture the embedded DSM, which includes both the existing and the forecasted EE that has been approved by the Commission and to do so without double-counting. I&M periodically reviews the methodology for estimating the effects of EE.

Director's Draft Report

From the narratives provided by I&M, it was not clear how the various models interacted. Moreover, it was not clear how the EE bundles were created and how I&M rolled off EE programs and avoided the double-counting of EE.

I&M's Reply Comments

I&M, in their written response and subsequent conversations, addressed concerns raised by the CAC et al. and the Commission's IRP staff about I&M's process for including EE in their load forecast, avoiding double-counting of EE (page 4 of I&M's response) by initially constructing a matrix of DSM programs that include the degraded value over time, the roll-off (or degradation) of existing EE, and the integration of new EE (efficiency gains to increasing appliance standards, programs approved by the Commission for three years, and evaluation of longer-term programs using PLEXOS).

Director's Response

I&M's commitment to improve the DSM and load forecasting databases by improving the quality, quantity, and granularity (e.g., sub-hourly demand data) will make more effective use of PLEXOS, improve the quality of the analysis, and enhance the credibility of all aspects of the IRP.

I&M's development of a 2016 Market Potential Study should improve the credibility of both the load forecast and the DSM programs.

The Director understands I&M's rationales for not including new utility-sponsored industrial DSM in the load forecast. However, there is a concern that the amount of cost-effective DSM might be understated because some industrial customers may have a shorter planning horizon than the utilities' planning horizons which adds to the challenge of long-term forecasting and planning. Understating the amount of cost-effective DSM would result in a higher load forecast, which would increase the amount of resources needed to satisfy the planning reserve requirements. The effect on load forecasts of unduly optimistic (or pessimistic) DSM projections could significantly affect the long-term resource decisions at a high cost to customers and the utility. Recognizing the merit of I&M's reluctance to quantify DSM for industrial customers, perhaps I&M might consider reducing (or increasing) the load forecast for industrial customers to give some effect to more (or less) DSM.

Similarly, the Director appreciates the sensitivity in showing forecasts for each industrial customer or making projections for combined heat and power (CHP) attributable to a specific customer for fear it may create problems for I&M and specific customers. For all of these circumstances, the Director wonders whether I&M could construct scenarios or sensitivities that put in a load and energy reduction in one scenario without attribution to a specific cause or customer. Similarly, recognizing there is a possibility of new industrial load over the 20-year planning horizon, would I&M consider a load increase without attributing the increase to a specific customer or a specific reason?

Summary and Conclusions

I&M's significant improvements in the 2015 – 2016 IRP and the several commitments to enhancements in future IRPs discussed previously could not have been done without the strong commitment by I&M's Chief Operating Officer Dr. Paul Chodak, other top management, and expert staff. The Director recognizes that I&M used this IRP as part of their own business analysis to assess the long-term viability of the Rockport units and potential alternative resources.

Given the uncertainty of natural gas costs, dynamic changes in the market value of coal-fired generating units in the RTO facilitated markets, the costs of renewable technologies, innovation in DSM, the potential for customer-owned generation, the CPP, and the potential ramifications of other environmental rules, this IRP was an appropriate time for I&M to concentrate on the future of the Rockport units because of their historic and future importance to the I&M system and I&M's customers. The Rockport units will be important considerations in future IRPs, but the Director trusts that future IRPs will be more expansive beyond the ongoing assessment of the Rockport units.

If, for example, the CPP is upheld by the Supreme Court, I&M and other utilities may have additional information available to conduct a more in-depth analysis of potential risks associated with the CPP in future IRPs. Regardless, future IRPs need to consider a broad range of scenarios and sensitivities to enable I&M and stakeholders to better consider all resources and their attendant risks.

With the risk factors previously discussed and the potential benefits of broad regional action such as compliance with the CPP and to mitigate adverse ramifications of a changing regional resource mix, the Director shares I&M's recognition of the need to inform their IRP with information from the operations and long-term resource planning of PJM Interconnection, LLC (PJM). Examples of this can be found on pages 59, 61, and 81 of I&M's IRP and page 7 of I&M's response. Future IRPs seem certain to address concerns about the profitability of coal-fired generation and, even, the Cook

Nuclear station within the PJM markets. The integration of additional renewable resources, customer-owned resources, EE, and demand response are all likely to warrant closer working relationships with PJM's operation and planning functions. Of course, there will always be unexpected issues.

Finally, as part of I&M's concerted efforts to improve the quality of the IRPs and make the IRPs more meaningful for stakeholders, the Director appreciates I&M's commitment to expanding the stakeholder process to encourage greater involvement by industrial and commercial customers. Hopefully, the additional year in the new IRP cycles will enable both I&M and its stakeholders to contribute to improvements in the quality and extent of participation from the inception of the IRP cycle to the analysis.

3. INDIANA MUNICIPAL POWER AGENCY'S INTEGRATED RESOURCE PLAN AND PLANNING PROCESS

This Final Director's Report reflects the following issues and emphasizes those that the Director regards as important concerns. This report does not address all the questions and concerns raised by the Director or stakeholders in the Draft Director's Report. The issues are:

- Load forecasting
- Demand Side Management (DSM)
- Relationship between load forecasting and DSM

IMPA's response to the draft report was helpful and informative. The Director wishes to note the following questions are to stimulate further thought and discussion and not to promote or advocate specific methodologies. The intent of the annual report is to challenge whether things can be done better, not just be done differently. Many, if not most, of the issues we address throughout this report are quite new and our collective knowledge and experience is too limited to make definitive recommendations.

Load Forecasting

IMPA's Load Forecasting

IMPA uses an auto-regressive approach (Auto-Regressive Integrated Moving Average - ARIMA) and includes explanatory variables such as Indiana real per capita income, U.S. unemployment, cooling degree days, and heating degree days for load forecasting. An ARIMA model uses lagged values of the dependent variable (kWh sales in this case) as predictors of future kWh sales. The integration component of the model provides a means of accounting for trends within a time series (pages 5 – 33 of IMPA's 2015 IRP).

IMPA adjusted the load forecast data. First, IMPA excluded from the forecast model 24 months of load data for the period 2009 – 2010. The intent was to exclude the effects of the December 2007 - June 2009 recession to better analyze the base trends and growth in load requirements affecting IMPA's service territory. Second, IMPA added the reductions in load from EE programs implemented from 2011 through 2014 back into the historical energy allowing the load forecasting statistical models to analyze the natural load growth.

Director's Draft Report

The Director asked a number of questions relating to these adjustments to better understand the basis for the changes and to determine how IMPA evaluated the potential limitations of using an ARIMA-based forecasting methodology. In addition, the Director wanted to know whether IMPA had explored alternatives to reliance on the ARIMA methodology.

IMPA's Reply Comments

IMPA explained it adjusts its historical loads to account for load variations not attributable to the explanatory economic variables. Although the economic explanatory variables included in the load forecast model may explain most, if not all of the recessionary impacts on load, the recessionary period did cause issues with the ARIMA function of the model. Therefore, IMPA excluded load data for the period 2009 – 2010 to allow both the ARIMA and econometric functions of the model to perform properly. No dummy variables were included in the models because creating dummy variables could introduce unintended bias. In IMPA's opinion, the rapid loss and subsequent partial recovery of electric load was such an unusual occurrence that this period is a statistical outlier and should be excluded from the load history.

Director's Response

The Director appreciates the difficulty and the need for judgement exercised by IMPA. However, the Director has a couple of conceptual questions for consideration. Is not the exclusion of data the same as using a dummy variable? If adding a dummy variable can introduce an unintended bias, then how or why does excluding the data avoid introducing a bias? Also, the Director is not sure what is meant by the statement that removal of the data helped both the ARIMA and the econometric functions of the forecasting models to perform better. Statistical measures normally used to test model performance will always improve when troublesome data is removed. The real question is whether the troublesome data is saying something that is lost when the data is removed.

Aside from IMPA's treatment of significant anomalies, in the Director's opinion ARIMA methods tend to be more suitable for short-term forecasting in which the relationship between the numerous factors affecting energy consumption over time is relatively stable or changing in a steady trend. It is poorly suited to capturing the effects of significant economic changes or other extraordinary events. We understand that IMPA used other economic explanatory variables to augment the ARIMA-type analysis, but it was not clear how well this worked. This is because IMPA stated that the economic variables may have explained most of the load impacts but still chose to remove the data for the period 2009 – 2010. The Director acknowledges that regardless of the methodology used it is very difficult to capture the effects of sudden extraordinary events on energy consumption. The Director is encouraged that IMPA continually evaluates its forecasting methodology and looks for additional data sources (page 2 of IMPA's response).

Demand-Side Management

IMPA's Demand-Side Management

IMPA, like other Indiana utilities, recently has started to include EE bundles in the optimization modeling process as a means to better compare EE with other resource options. This methodology contrasts with the primary method, used until quite recently, of including EE as an adjustment to the load forecast, which then is used to optimize the supply-side resource portfolio. In other words, the optimization of generation resources mainly was done separately from the determination of the demand-side resources. The new methodology requires EE to be packaged into bundles or blocks for inclusion in the resource optimization models.

Director's Draft Report

There appear to be numerous similarities and differences as to how Indiana utilities create these EE bundles. IMPA's IRP provided a good but incomplete overview of how it developed the EE bundles or blocks. In the draft report, the Director sought more detail to better understand how IMPA built its bundles and the information used.

IMPA's Reply Comments

In lieu of attempting to model many existing as well as yet-to-be-defined future EE offerings, IMPA chose to model representative EE blocks. This avoided the use of DSM screening models that rely heavily on static avoided costs. The basis for the creation of the costs and load shapes of the EE blocks was IMPA's actual EE results observed during the Energizing Indiana program.

To develop a load shape, data from all five Energizing Indiana programs was used to compile an 8,760 hourly load shape for the EE block. All blocks used the same load shape. The five programs were Residential Lighting, C&I rebates, Home Energy Audits, Schools, and Low-income

Weatherization. The cost of the blocks is the primary differentiating characteristic. The blocks were divided into three cost levels to represent the increasing cost of EE programs as more difficult and expensive programs are implemented. As with the cost of supply-side resources, the cost of EE programs escalated through the expansion period. There was no attempt to model technological improvements (page 8 of IMPA's response).

Director's Response

The information on EE block preparation included in the IRP and IMPA's reply comments is helpful but still leaves a major question unanswered. How were the EE block costs determined for each level, and how were these costs escalated over time? IMPA is not alone in this circumstance. None of the utilities that prepared 2015 IRPs provided a satisfactory level of detail. Another question or concern is that IMPA did not attempt to account for technological change. This is understandable given the complexity of projecting technological change. However, is this reasonable given the rapid technological change being seen and probably to some extent reflected in the load forecast? The issue of how to treat technological change when modeling EE is an open question and is being addressed differently by different utilities.

IMPA developed its EE blocks based on its experience, primarily with the Energizing Indiana programs for the period 2011 – 2014. Recognizing IMPA's unique relationship as a wholesale provider, is sole reliance on experience an adequate substitute for not having a DSM market potential study? Could IMPA make good use of market potential studies prepared for other Indiana utilities? What is the relationship between a market potential study and the development of EE blocks? The Director recognizes that these questions are not unique to IMPA and may be in a sense problematic for IMPA given their structure and relationship with their members which limits IMPA's authority over DSM decisions.

Relationship between Load Forecasting and DSM

Relationship Between IMPA's Load Forecasting and DSM

As noted previously, IMPA adjusts its historical load data to account for load variations not attributable to the explanatory economic variables. According to IMPA, historical EE programs implemented by IMPA for the period 2011 – 2014 require such a modification.

Director's Draft Report

The Director asked a number of questions in the draft report to attempt to better understand what adjustments were made and how. The primary concern expressed by the Director was to better understand how IMPA attempts to avoid double-counting energy efficiency. A potential for double-counting exists because the load forecast reflects at least in part the historic EE improvements caused by both naturally occurring EE improvements over time and those improvements resulting from utility's EE programs. The issue is how to avoid double-counting the effects of EE captured in the load forecast and efficiency improvements from current and future utility programs.

IMPA's Reply Comments

IMPA notes EE reductions attributable to IMPA's EE program are driven by program incentives rather than explanatory economic variables, so the program-related EE reductions are added back to IMPA's historical load data. For EE installed for the period 2011 – 2014, IMPA assumes the effects of the measures will not disappear over time. For example, if a customer replaced inefficient lights in a factory by participating in an IMPA EE program, then even after the lights eventually burn out,

the factory will replace them with similar (or better) light bulbs. The adding back of energy saved through IMPA EE programs provides a consistent historical database for developing the “gross” load forecast. The load forecast model is estimated using this gross load historical data. After the gross load forecast is estimated, the historical EE reductions are subtracted from the gross load forecast resulting in the “net” or final load forecast, which does not include the historic EE (pages 2 – 3 of IMPA’s response).

IMPA also says it uses its scenario process to address improving efficiency over time by adjusting the load factors. For example, the Green Revolution scenario improves the load factor by 3% by 2030 due to residential rooftop solar, batteries, and energy efficiency (page 5 of IMPA’s response).

Director’s Response

The issue of how best to prepare a load forecast and avoid or minimize the potential for double-counting between EE reflected in the load forecast and utility-sponsored EE programs is a subject of debate with different methodologies being subject to various pros and cons. The discussion here is more to provoke greater thought than specific changes or methodologies. Utility EE programs move up EE that probably would have occurred at a later date. The impacts or effects of historical, utility-sponsored EE should taper off over time and be replaced as naturally occurring (organic) EE replaces these program effects. This appears to be what IMPA assumes in its modeling. IMPA’s methodology is reasonable.

IMPA’s statement that in the various scenarios the load factor is adjusted to account for improving efficiency over time raises multiple questions. How is the adjustment determined? This adjustment represents incremental EE improvements for the specific scenario relative to the base case. Because the efficiency improvement included in the base case seems to be unknown, is there double-counting or under-counting when the load factor is adjusted?

IMPA notes in its reply comments that it is possible to miss some of the effects of organically occurring EE in future load requirements. For example, in the Director’s opinion, IMPA’s load forecasting methodology has difficulty capturing the effects of government appliance efficiency standards that will take effect in the future. This is especially the case if these standards are significant structural changes that cause improvements in appliance efficiencies beyond trends reflected in historical data. These types of changes are better or more easily captured in SAE models. However, these type of models are difficult for IMPA to implement given its role as a wholesale provider of electric power and its relationship with its retail municipal members. IMPA states it will continue to investigate ways to assess the impact of organically occurring EE as well as free riders. The Director notes the limited scale of IMPA’s EE programs means that the treatment of energy efficiency, both organic and utility-sponsored EE programs, in the load forecast is probably a smaller concern than for other utilities with more extensive EE programs over time.

Other Matters

The Director wishes to acknowledge the extensive risk metrics IMPA provided in its IRP. These included

- Stochastic risk profiles
- Tornado charts with detailed metrics of 10 independent variables
- Stochastic mean comparisons
- Risk profile comparisons

- Trade-off diagram between present value of revenue requirements (PVRR) and average system rate (ASR)
- Efficient frontier of ASR versus standard deviation
- Comparison of levelized ASR
- Comparison of levelized PVRR
- Risk confidence bands around ASR
- Several charts detailing CO₂ and natural gas risk

Summary and Conclusions

For the most part, IMPA uses state-of-the-art models to develop its IRP and applies interesting techniques while making use of data developed by the Energy Information Administration. This is especially true when it comes to the risk and uncertainty analysis performed by IMPA. However, IMPA's status as a wholesale supplier of bulk power to its members imposes limitations in the IRP development process that are especially obvious in the areas of load forecasting, DSM analysis, and the interrelationship between the two.

The Director encourages IMPA to explore its ability to develop a DSM market potential study to improve its DSM analysis. Recognizing IMPA's position, it might be possible for IMPA to place some reliance on the market potential studies developed by other Indiana utilities. Such an approach is likely to be cost effective. Supplementing IMPA-specific data with data from other Indiana utilities that serve areas in close proximity to those served by IMPA's members would have the added benefit of enhancing credibility by capturing applicable similarities. In addition, for energy efficiency, demand response, and customer-owned resources, integrating data from other somewhat comparable utilities enables IMPA's analysis to be more forward-looking using data that reflects Indiana circumstances rather than heavily relying on historical programs and experience. Consideration of program experience is important but perhaps slightly less so when technology is changing so rapidly.

The previous discussion has a number of questions that are designed to provoke additional thought as to if and how some aspects of the IRP can be improved. Similar to other Indiana electric utilities that submitted 2015 IRPs, IMPA could provide better descriptions and more information in the specified areas to improve a reader's understanding of what it did and why. The Director acknowledges IMPA's statements in its reply comments to explore several areas for possible improvement in the future.

4. WVPA's INTEGRATED RESOURCE PLAN AND PLANNING PROCESS

This Final Director's Report reflects the following issues and emphasizes those that the Director regards as important concerns. This report does not address all the questions and concerns raised by the Director or stakeholders in the Draft Director's Report. The issues are

- Load forecasting
- Demand Side Management (DSM)
- Relationship between load forecasting and DSM
- Resource optimization

Wabash Valley Power Association's (WVPA's) response to the draft report was helpful and informative. The Director wishes to note the following questions are to stimulate further thought and discussion and not to promote or advocate specific methodologies. The intent of the annual report is to challenge whether things can be done better, not just be done differently. Many, if not most, of the issues we address throughout this report are quite new and our collective knowledge and experience is too limited to make definitive recommendations.

Load Forecasting

WVPA's Load Forecasting

WVPA's forecast consists of the summation of the individual member systems, so the forecast represents a bottom-up approach. The number of customers and energy sales were projected at the customer class level and aggregated to produce the total system forecast. Econometric methods were used to forecast the number of residential and small commercial customers and average use per residential or small commercial customer. For example, the projected number of residential customers in a given year is multiplied by the projected average use per residential customer for that year to derive the total residential load for that member. According to the IRP, energy sales and peak demand for large commercial customers were developed by cooperative member staff using historical trends and information made available by the individual customers, such as knowledge of expansions, new construction, and so on.

Director's Draft Report

The Director recognizes that WVPA's relationship with its member cooperatives imposes some limitations on the forecasting process. Combining the load forecasts for each of the members poses some challenges. The Director sought to clarify whether a full SAE model for the residential class was used by WVPA and to clarify whether the large commercial forecast was based on informed opinion alone or if some type of econometric techniques also were used.

WVPA's Reply Comments

WVPA said the load forecasts for large commercial customers are based on informed opinion. They generally adjust only the first one to two years for probable load growth. Beyond the first two years, WVPA assumes 0.0% – 2.0% load growth for any individual customer. WVPA also indicated they have not attempted to model the load of these larger customers using econometric techniques.

Director's Response

The techniques used to model the residential and small commercial customer energy requirements seem to be reasonable, but the large commercial customer methodology raises some questions. Over what period does each member provide its judgement-based large customer load forecast: 1 year, 5 years, 10 years, or some other time period? How does WVPA decide which load growth rate to

apply to individual customers? Does this growth rate differ across customers, and on what basis is this decision made? How is the trend of increasing EE over time captured in an industrial load forecast based entirely on professional judgement?

Demand-side Management

WVPA's Demand-side Management

WVPA, like other Indiana utilities, recently started to include EE bundles in the optimization modeling process as a means to better compare EE with other resource options. This methodology contrasts with the primary method until quite recently of including EE as an adjustment to the load forecast, which was then used to optimize the supply-side resource portfolio. In other words, the optimization of generation resources was done largely separate from the determination of the demand-side resources. The new methodology requires EE to be packaged into bundles or blocks for inclusion in the resource optimization models. That is, the model selects the most appropriate resource based on its relative merits and is indifferent to the type of resource.

Director's Draft Report

There appear to be numerous similarities and differences as to how Indiana utilities create these EE bundles. In its IRP, WVPA provided an incomplete overview of how it developed the EE bundles or blocks because the discussion focused almost entirely on their internal administrative process for developing an EE plan. WVPA's IRP noted the use of a condensed study of achievable efficiency potential. In the draft report, the Director sought more detail to better understand how WVPA built its EE packages (expansion alternatives) and the information used.

WVPA's Reply Comments

WVPA clarified that the condensed study of achievable efficiency potential was based on a "compilation of studies prepared for other clients with similar customer demographics" (page 11 of WVPA's response). Navigant Consulting conducted a meta-review of other recently completed potential studies for utilities in a similar geographical territory to WVPA. Navigant reviewed potential studies for Entergy Arkansas (2015), Kansas City Power and Light (2013), and Commonwealth Edison (2013) (page 12 of WVPA's response). WVPA did not research or consider technical or economic potential specific to WVPA. The meta-analysis of other potential studies focused solely on achievable potential (page 12 of WVPA's response). WVPA determined that a meta-analysis was a reasonable and appropriate methodology to estimate achievable EE market potential when weighed against available resources and the cost of a potential study specific to WVPA's service territory.

Director's Response

The Director does not disagree with the decision to rely on a study that consisted of a meta-analysis of other utility market potential studies. The Director now understands that the EE resource alternatives included in the resource optimization are based on a combination of market potential studies developed for three specific utilities thought to have similar geographic and demographic characteristics. It is appropriate to consider information from other utilities. However, the credibility of the narrative supporting the analysis would be enhanced if there was greater reliance on WVPA- and state-specific data.

The Director also still does not really know how the EE resource alternatives were developed. Which EE measures are included in the 1 MW Residential, 1 MW Small Commercial, and 1 MW

Large Commercial EE resource alternatives? How were the load shapes for the resource alternatives developed from the individual measure characteristics? How were the costs derived for each resource alternative, given the cost and performance characteristics of the measures reflected in the resource alternative?

The Director notes that had WVPA provided adequate detail, an informed reader of the IRP could more fully understand the data and analytical process used to create the three resource alternatives. The Director also recognizes that determining how much detail is enough but not too much is also a matter of judgment. For example, what to include in the body of the IRP report and what should be put in an appendix? The Director would like to acknowledge that WVPA's role as a wholesale supplier of electric service and its relationship with its cooperative members also affects WVPA's long-term resource planning process and resource acquisition.

Relationship between Load Forecasting and DSM

WVPA's Load Forecasting and DSM Integration

The difficult question is what part of future EE programs is truly incremental to what has been captured in the historical data and is thus already reflected in the load forecast? The interrelationship between a load forecast and how to reflect the impact of future incremental utility EE programs is complex because it depends on at least a couple of considerations. One is the methodology used to develop the forecast; another probably involves the scale of the utility EE programs over time and whether they are increasing, decreasing, or holding steady over a period of several years. For example, how does this historical performance compare to the scale of future EE programs included in the utility resource acquisition plan?

Both Duke and I&M use an SAE model for developing their forecasts of residential and commercial loads. Both Duke and I&M also use primarily econometric methods for industrial and other customer classes. SAE models enable one means of explicitly reflecting naturally occurring EE and capturing historical trends. However, even here, considerable professional judgment is required to adjust how current and future EE programs impact the load forecast.

As noted previously, WVPA explained in the IRP that they used econometric methods to forecast the number of residential and small commercial customers and the average use for each class. The models include variables to capture space heating and cooling. They also include a base index from an SAE model in the residential average use model. The base index is said to capture the general trend associated with increasing penetration of plug-in appliances, lighting, and water heating. The index is modified to include the impacts associated with the price of electricity, household income, and number of people in the household.

The Director's Draft Report

In the Draft Report, the Director sought additional information to better understand how the interrelationship between EE and the load forecast was addressed.

WVPA's Reply Comments

WVPA clarified that they did not use an SAE model. WVPA also clarified that they did not remove the effects of utility program EE from the historical load data prior to estimating the residential and small commercial models. They note that all existing EE programs are embedded as a reduction to their historical load numbers.

Director's Response

The Director reiterates the complexity of these matters and acknowledges that there is no single correct answer to these questions or issues. Rather, the focus is on asking questions to stimulate thoughtful consideration of whether something can be improved upon, not merely done differently.

Given the information provided by WVPA in the IRP and their reply comments, it is clear WVPA is not directly addressing the issue of whether it is double-counting or under-counting the impacts of utility EE programs going forward. As noted previously, much depends on the modeling techniques used and what has happened historically regarding the scale of utility-sponsored EE programs and what is projected to be acquired in the forecast period.

One clear difficulty is associated with how WVPA forecast load for large commercial customers. The reliance on informed opinion to specify specific annual growth rates for individual customers leaves open the question of whether historical efficiency trends are being captured in these customer-specific forecasts. Econometric methodologies at least capture these trends because they are reflected in the historical load data and are carried forward in the forecast. How is this done in a process that relies entirely on informed opinion?

Resource Optimization

WVPA's Resource Optimization

It needs to be emphasized that WVPA acquired the PLEXOS modeling system several months prior to using it for the first time in the 2015 IRP. The new model provides significant capability, and WVPA acknowledges they will be able to more fully exploit this as they gain experience with the model. The Director appreciates the difficulty associated with transitioning to a new, complex model and WVPA's desire to improve their resource planning capabilities. To the extent fuller use of the PLEXOS model requires different databases, the Director encourages WVPA to explore ways to develop the requisite information.

WVPA used a sequence of scenario analysis and stochastic analysis to develop potential resource plans. The stochastic analysis was used to review the impact of various risk components on the resource plans developed under the various scenarios. The risk components included load; both peak demand and energy; market prices for wholesale electric power, natural gas, and coal; and a carbon tax.

The Director's Draft Report

The Director asked several questions related to various aspects of the modeling performed by WVPA. For example, the Director specifically sought to clarify the extent to which WVPA actually used scenario analysis, asked why the model results tended to reflect short-run overbuilds of generation resources in particular years, and requested more details on how the stochastic analysis was performed.

WVPA's Reply Comments

According to the IRP, WVPA developed four alternative scenarios in addition to a base scenario for which resource plans were developed. The performance of these resource plans was further reviewed with stochastic analysis, which is another means to review the impact of uncertainty on a resource plan. WVPA's reply comments noted that the term *sensitivity* is probably a better

description of all WVPA's alternative expansion plans as they made minimal changes to the model to see how the expansion plans changed in the PLEXOS LT Plan (page 6 of WVPA response).

The Director's Draft Report also noted the power expansion planning analysis results tended, in the short run, to overbuild or to acquire more resources than necessary at any given point in time. WVPA acknowledged the model tends to overbuild. This is a result of allowing only fossil fuel construction in only certain years of obvious need. According to WVPA, the alternative would be to allow for construction of a 59 MW CT/CC in 2016, another 123 MWs in 2017, and 86 MW in 2018. They state this is not how WVPA manages its portfolio. Another alternative would be to allow the model to purchase capacity, but this could lead to under-building (page 7 of WVPA's response).

WVPA also notes large generation additions are expensive and, for use in the resource planning models, makes these resources relatively "lumpy" compared to DSM and some renewable resources that can be modeled in lower capacity amounts. Care must be taken so that there is neither a bias in favor of or against any type of resource. So WVPA intends to manage short-term short or long capacity positions with market capacity transactions to help manage large capacity investment costs (page 7 of WVPA's response).

WVPA eliminated market sales and limited market purchases in their analysis. Due to this underlying assumption, generation needs were mainly provided through expansion alternatives (page 9 of WVPA's response).

WVPA also clarified that they modeled the scenarios/sensitivities (Optimistic Economy, Pessimistic Economy, Carbon Emissions Regulation, and pulverized Coal Resource Addition) as separate expansion plans and executed them with all combinations of defined stochastic variables (Load, energy Price, Natural Gas Price, Coal Price, Energy Price, and Carbon Tax). (page 9 of WVPA's response).

Director's Response

The Director appreciates WVPA's clarification that what was described in the IRP as scenarios is more appropriately seen as sensitivities. *Scenarios* are more commonly thought of as alternative visions or stories of potential futures. A *sensitivity* is basically where there is a specific scenario and only a single variable (or a very limited number of interrelated variables) is changed to see how the resource plan is altered or performs under the limited change.

The Director believes that the analysis could be made better if WVPA developed several true distinct scenarios that were optimized and the resulting resource plans were subjected to stochastic analysis. This limitation may be less problematic because WVPA seems to have performed a reasonable stochastic analysis to better understand the impact of uncertainty across several variables on the various resource plans. Tornado charts were presented for each expansion plan showing the range of the impact of the individual risk factors on the plan, which is helpful.

With respect to the model's tendency to overbuild resources in certain years, the Director appreciates the clarifications but finds the rationale confusing. WVPA states that the overbuilding is a result of allowing fossil fuel construction in only certain years of obvious need. They also limited the model's ability to make market purchases and eliminated market sales entirely. WVPA dismisses the alternative as inconsistent with how they manage their portfolio.

It is the Director's opinion and observation that the rejected alternative is exactly how WVPA operates. Because WVPA recognizes the inherent "lumpiness" of major investments in resources, they rely on numerous purchase power agreements to smooth their resource development. Then, they build or purchase generation facilities when circumstances warrant. It would be surprising if expanded DSM would not be objectively selected by PLEXOS as part of the smoothing of future resource plans. The Director thinks that a portfolio that allows necessary additions in all years instead of limiting it to certain years would provide the same guidance when evaluating resource opportunities without giving the impression that WVPA has biased resource decisions by substituting its constraints for the objective computer analysis of PLEXOS. It will be interesting to see whether WVPA's concerns about the operation of the PLEXOS model are resolved for the next IRP. The Director also recognizes that it is not clear whether either method is better in any important sense.

Summary and Conclusions

The Director appreciates WVPA's acquisition and use of the PLEXOS modeling system and WVPA's willingness to use it in this IRP even as WVPA is still learning how to make better use of the model's capabilities. It is no small task to transition to a new, complex model over a relatively short period of time.

WVPA's ability to perform risk and uncertainty analysis should be improved as the PLEXOS model is used more effectively in the future. Nevertheless, an improved model cannot offset a failure to develop multiple true scenarios in the IRP process. WVPA acknowledges they relied on what can more properly be called sensitivities. WVPA appears to have conducted a reasonable stochastic analysis, but WVPA's risk and uncertainty analysis would have been improved if the stochastic analysis had been applied to results derived from optimizing well-developed scenarios.

The Director understands WVPA's use of a meta-analysis of other utilities' DSM market potential studies as a cost-effective way to improve the information relied on by WVPA. However, all these market potential studies were for non-Indiana utilities. The Director believes greater reliance on Indiana-specific data would be a better choice. This could be done as a meta-analysis of market potential studies performed for other Indiana utilities. Like the other Indiana electric utilities that submitted 2015 IRPs, WVPA made significant changes to make the treatment of EE more comparable to other resource options. As was the case with the other Indiana utilities, WVPA created DSM bundles that could be included in the model resource optimization process. Similar to these other utilities, in future IRPs, WVPA needs to provide greater detail and clarity as to how the bundles were developed and the data and assumptions used.