REPORT

OF

THE INDIANA UTILITY REGULATORY COMMISSION

ELECTRICITY DIVISION DIRECTOR

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REGARDING 2013 INTEGRATED RESOURCE PLANS

Date of the Report: April 30, 2014

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 Electricity 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. Section 2(k) of the Draft Proposed Rule limits the report to the informational, procedural, and methodological requirements of the rule. The Draft Proposed Rule goes on to say 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.

Considering the utilities have moved forward with using the Draft Proposed Rule for the IRPs they've submitted in November 2013, for purposes of preparation of this report, the Commission has decided to act as if the Draft Proposed Rule is in effect. This report was written to comply with the requirements specified above.

Four Indiana utilities submitted IRPs on November 1, 2013. The four are:

1. Duke Energy Indiana
2. Indiana Michigan Power Company
3. Indiana Municipal Power Agency
4. Wabash Valley Power Association

Written comments on the integrated resource plans were submitted by:

1. Clean Line Energy
2. Citizen Action Coalition, Earthjustice, and Sierra Club
3. Hoosier Environmental Council
4. Wind on the Wires

The draft report by the Electricity Director was issued February 28, 2014.

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 were submitted by:

1. Citizens Action Coalition, Earthjustice, Mullett & Associates, and Sierra Club
2. Duke Energy Indiana
3. Indiana Michigan Power Company
4. Indiana Municipal Power Agency
5. Indiana Office of Utility Consumer Counselor
6. Wabash Valley Power Association

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 DRAFT IRP PROPOSED RULE:

The Draft Integrated Resource Planning (IRP) Proposed Rule emanates from the "Certificate of Need"[1] law. Generally, the Certificate of Need law is intended to better ensure that electric utility services would be provided to Indiana citizens at the lowest reasonable cost consistent with reliable service. The Draft Proposed Rule,[2] developed in collaboration with Indiana's utilities and interested stakeholders, is intended to modernize and streamline the existing IRP Rule to help utilities and the Indiana Utility

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[1] **IC 8-1-8.5-3 Analysis of needs; plans: Note the draft IRP Proposed Rule was a collaborative effort to modernize the original IRP Rule (Adopted in 1995)** Sec. 3.
(a) The commission shall develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity.
(b) This analysis must include an estimate of:
(1) the probable future growth of the use of electricity;
(2) the probable needed generating reserves;
(3) in the judgment of the commission, the optimal extent, size, mix, and general location of generating plants;
(4) in the judgment of the commission, the optimal arrangements for statewide or regional pooling of power and arrangements with other utilities and energy suppliers to achieve maximum efficiencies for the benefit of the people of Indiana; and
(5) the comparative costs of meeting future growth by other means of providing reliable, efficient, and economic electric service, including purchase of power, joint ownership of facilities, refurbishment of existing facilities, conservation, load management, and cogeneration.
(c) The commission shall consider the analysis in acting upon any petition by any utility for construction.
(d) In developing the analysis, the commission:
(1) shall confer and consult with:
(A) the public utilities in Indiana;
(B) the utility commissions or comparable agencies of neighboring states;
(C) the Federal Energy Regulatory Commission; and
(D) other agencies having relevant information; and
(2) may participate as it considers useful in any joint boards investigating generating plant sites or the probable needs for future generating facilities.
(e) In addition to such reports as public utilities may be required by statute or rule of the commission to file with the commission, a utility may submit to the commission its utility specific proposals as to the future needs for electricity to serve the people of the state or the area served by the utility.
(f) Insofar as practicable, each utility, the utility consumer counselor, and any intervenor may attend or be represented at any formal conference conducted by the commission in developing a plan for the future requirements of electricity for Indiana or this region.
(g) In the course of making the analysis and developing the plan required by this section, the commission shall conduct one (1) or more public hearings.
(h) Each year, the commission shall submit to the governor and to the appropriate committees of the general assembly a report of its analysis and plan, the progress to date in carrying out such plan, and the program of the commission for the ensuing year in connection with such plan.
As added by P.L.43-1983, SE SEC.12. Amended by P.L.88-1985, SEC.7; P.L.53-1992, SEC.2.

[2] **170 IAC 4-7 Guidelines for Integrated Resource Planning by an Electric Utility** Authority: IC 8-1-1-3
Affected: IC 8-1-8.5; IC 8-1.5

Regulatory Commission (IURC) comply with the legislative intent and statutory requirements of the Certificate of Need law by fostering continual improvements to long-term resource planning processes.

Recognizing utilities, their customers, and the State of Indiana have, to a larger degree, common cause in insuring economical and reliable electric service, it has always been the intention of the IURC that a successful IRP collaborative process will mitigate controversy associated with major resource decisions. Ideally, the reduced controversy will expedite the construction or implementation of all forms of cost-effective resources, foster transparency, and provide a higher degree of assurance of cost recovery for resource decisions that are prudently incurred.

The most significant change in the Draft Proposed Rule, compared to the existing Rule, recognizes that Indiana utilities are part of a broad and diverse region that is increasingly interconnected and by the development of Regional Transmission Organizations (RTOs) such as the Mid Continent Independent System Operator, Inc. (MISO – in Carmel, Indiana) and the PJM Interconnection, LLC (PJM). The Certificate of Need statute was prescient in requiring utilities to consider regional resource plans rather than continue to plan as if they were islands with sole responsibility for meeting their resource needs.

In addition to increased regional perspectives and reliance on RTOs, the collaborative development of the Draft Proposed Rule recognized:

- Increasingly stringent environmental regulation was likely to have dramatic ramifications for future generating resources in Indiana and Nationally. Carbon regulation could be a *game changer* that could dramatically reduce coal-fired generation in Indiana and throughout the Eastern Interconnection.
- Just in the last couple of years, the enormous potential of natural gas has resulted in projections of abundant and relatively low-cost natural gas for decades to come. If the promise of low-cost natural gas is realized, it could – potentially – compete with some coal-fired generation.
- Reduced demand for electricity is also a distinct possibility due to continual improvements in appliance / end-use efficiency, utility programs to promote energy efficiency and demand management. In sharp contrast to the 1960s – 1970s where very high forecasts of demand for electricity led to the boom in construction of new generating facilities that, in turn, led to excess capacity and high rates, in recent years all of the Indiana utilities have experienced continual declines in the growth rate of energy sales. The forecast is for low load growth and, for some utilities, declining electric use is a real possibility.
- The development of significant amounts of low cost renewable resources, particularly wind resources, has become an increasingly important component of Indiana's resource mix. It is also conceivable that other forms of distributed generation will increase which will further reduce the need for traditional utility-owned generating facilities.

Understanding the potential ramifications of these "risks," for utilities and their customers is the primary objective of the collaborative IRP process.

The Indiana utilities that participated in this first round of IRPs are to be commended for their work under the Draft Proposed Rule. Certainly in comparison to prior years, these IRPs are much improved in process, use of analytical tools, analysis, and credibility of results. However, as the comments below illustrate, the Commission Staff believes that continual efforts to improve the quality and credibility of the IRPs are warranted by the extraordinary risks faced by utilities over the next 20 years or more.

A. Requirement – Demonstrate that supply-side and demand-side resource alternatives have been evaluated on a consistent and comparable basis.

170 IAC 4-7-8 Resource integration

Authority: IC 8-1-1-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 8. (a) The utility shall develop candidate resource portfolios from the selection of future resources in section 7 and provide a description of its process for developing its candidate resource portfolios.

(b) From its candidate resource portfolios, a utility shall select a preferred resource portfolio and provide, at a minimum, the following information:

(1) Describe the utility's preferred resource portfolio.

(2) Identify the variables, standards of reliability, and other assumptions expected to have the greatest effect on the preferred resource portfolio.

(3) Demonstrate that supply-side and demand-side resource alternatives have been evaluated on a consistent and comparable basis.

(4) Demonstrate that the preferred resource portfolio utilizes, to the extent practical, all economical load management, demand side management, technology relying on renewable resources, cogeneration, distributed generation, energy storage, transmission, and energy efficiency improvements as sources of new supply.

It is clear the Draft IRP Proposed rule requires that supply-side and demand-side resources be evaluated on a consistent and comparable basis. One can question what is meant by "consistent and comparable basis" and reasonable people can disagree as to what must be done for this requirement to be met, but it is indisputable that utilities in their IRPs must attempt to evaluate supply-side and demand-side resources in something resembling a comparable manner. Unfortunately, the IRPs submitted by Duke Energy Indiana, Indiana Michigan Power Company, Indiana Municipal Power Agency, and Wabash Valley Power Association do not satisfy this requirement.

Duke Energy Indiana

The resource optimization process for each scenario was restricted by hardwiring the impact of energy efficiency resources over the modeling horizon. Prior to optimization each scenario was assumed to have a specified level of energy efficiency. The Reference Scenario: *"assumes compliance with the Commission's Phase II Order, reaching 11.9% of retail sales by 2019 and then maintaining 11.9% through 2033 (p 109, Duke IRP)."* The Low Regulation Scenario assumes that energy efficiency does not reach 11.9% of retail sales until 2033. The Environmental Focus Scenario assumes energy efficiency reaches 11.9% of retail sales by 2019 and increases to 15% by 2032.

In reply to the draft report, Duke noted that the "*three different levels of EE were developed to be consistent with the themes of the respective scenarios developed during the IRP stakeholder process*" (page 7, Duke Reply Comments). Duke also noted the challenges to developing long term assumptions for EE given how programs mature differently, new technologies are developed, and the potential for regulatory changes (page 8, Duke Reply Comments).

We acknowledge the difficulty of developing long term assumptions for something as complex and ever changing as EE opportunities, but it is not clear an appropriate solution is to hardwire specific EE impacts. As noted by the Comments of Citizens Action Coalition of Indiana, Inc., Earthjustice, Mullett & Associates and Sierra Club (CAC et al) on Duke's IRP, the Company's modeling does not optimize energy efficiency by letting efficiency compete with supply-side resources (page 20). CAC et al also mention the costs that Duke is assuming for EE are unknown and thus cannot be compared to other information sources (page 20). We note the lack of data would be more significant if EE was actually allowed to compete with supply-side resource options.

Indiana Michigan Power Company

I&M did not allow EE to compete with supply-side resources in an optimization process over the full planning horizon. Through 2019 the company hardwired the impact of EE at a level designed to comply with the Phase II DSM Order requirements, to the extent practicable (page 8, I&M IRP). Beginning in 2020, I&M did allow incremental EE programs to compete with other resource options in the optimization process. I&M used data from Efficiency Vermont to evaluate a "*comprehensive portfolio of measures necessary to achieve large energy reductions.*" (I&M IRP, page 90) Two optimized resource plans were developed with both adding 249 MW of DSM over the period 2020-2033.

I&M did not explain or demonstrate in the IRP how the practicable level of EE was established through 2019. In their Reply Comments (page 9), they state:

> *The reduced quantity of energy efficiency assumed embedded in the forecast was the result of management judgment given the realized results of the prior three years and the phase-in of lighting standards, which will greatly reduce the ability of future energy efficiency programs to achieve lasting energy savings above the load forecasts which will naturally include those standards*.

It is clear that I&M assumed a specified level of EE in the resource plan and that this impact was based on management judgment through 2019. I&M did allow incremental EE to compete directly with other resources for the period 2020-2033. However, as noted by the CAC et al we are not provided in the IRP any information to understand how EE was modeled (page 9 CAC et al on I&M IRP) and the necessary data is not specified beyond providing a link to the Efficiency Vermont website (page 11, Comments on I&M IRP).

I&M's Reply Comments (pages 10 & 11) clarify that I&M used the cost and performance statistics of energy efficiency programs administered by Efficiency Vermont for the year 2011 and available on the EV website. The reply went on to say that costs were faithfully replicated while performance data was altered in the following ways:

1. For climate-sensitive measures such as air conditioning and heating, I&M-specific cooling degree days and heating degree days were used.
2. Net-to-gross values for lighting measures were changed to reflect more typical values.
3. Lighting performance was reduced to reflect the standards that are in place currently that were not in place in 2011.

Staff notes this additional information is helpful but does little to clarify how EE was modeled.

Similar to Duke, I&M in Reply Comments (page 9) stated that EE is a very difficult resource to quantify prospectively in terms of cost and performance. They cited the vast differences between reported past program performance in other, dissimilar states prior to the phase-in of significant efficiency standards and industry-intensive, high heating and cooling load, post phase-in, Indiana.

Staff acknowledges the difficulty of quantifying prospectively EE resources in terms of costs and performance. Nevertheless, the problems appear to have been addressed by I&M given that it did model incremental EE in the optimization process for the period 2020-2033. If I&M could optimize EE for the period 2020-2033, why could I&M not model EE for the period through 2019?

Indiana Municipal Power Agency

IMPA hardwired the impact of energy efficiency programs into the Capacity Expansion module. IMPA has a long-term strategic plan that includes an aspirational target of a 10% reduction in projected demand and energy requirements by 2020 to be achieved through cost effective energy efficiency programs. They note that experience with the state-wide Core program has shown that it may not be cost effective to reach the target. On page 11-128, IMPA states that two demand-side management penetration levels (Base-EE and High-EE) were designed from a list of individual programs. The Base-EE reflects the expected savings by 2020 "*garnered from IMPA's experience with Energizing Indiana, while the High-EE forecast reflects IMPA's aspirational goal of 10% by 2020.*" The Base-EE reaches a 2.5% cumulative savings by 2020.

Beyond describing the current EE programs and the EE included in the Capacity Expansion Module there is little discussion of future programs and some of this was out of date shortly after the IRP was sent to the Commission on November 1, 2013. IMPA's action plan is briefly discussed on page 1-10 where it says IMPA will:

1. Continue involvement in the Energizing Indiana program through 2014
2. Acquire energy efficiency cost/benefit evaluation tools
3. Evaluate benefits and costs of continued participation in the Energizing Indiana program compared to a slate of IMPA initiated programs.

On December 16, 2013, IMPA notified the Commission that IMPA had sent notice to GoodCents on December 13, 2013 terminating, effective January 1, 2014, its contract with GoodCents. The notice to the Commission also said that IMPA intended to develop internally managed energy efficiency programs for its members. The Commission approved IMPA's motion to withdraw its voluntary participation on January 22, 2014.

It is troubling that something IMPA included in the short-term action plan was changed so abruptly only a few weeks after the IRP was sent to the Commission. It is all the more imperative that IMPA acquire the necessary EE evaluation models and, more importantly, work with its members to acquire the detailed data necessary to develop and successfully implement EE programs.

IMPA discusses some of the problems associated with collecting the necessary data (pages 5-42 & 5-43). This discussion is in the context of explaining why IMPA does not use alternative methods of performing load forecasting, but it clearly has implications for EE planning and implementation.

1. IMPA does not forecast demand and energy requirements by rate classification or sector.
2. IMPA does not have direct access to customer billing units.
3. IMPA would need to collect several years of annual historical billing summary data from each of its 60 members to develop a customer sector forecast.
4. IMPA's member communities are not uniform, consisting of various ages of homes and businesses. The age of residents and the vintage of homes can have a significant impact on the saturation of various appliances.

In its reply comments (pages 4-5), IMPA reiterates the limitations imposed by its status as a wholesale utility:

> *IMPA is in fact a wholesale utility with no retail customers and no ability or authority to access information regarding its members' retail sales. Those circumstances are not something IMPA can unilaterally "resolve" prior to its next IRP. Rather, IMPA's status as a wholesale electric provider is a fundamental trait. Because IMPA is not a vertically integrated electric utility, IMPA acknowledged in its IRP that, in many cases, it is unable to conduct its planning in the manner contemplated by the Commission's IRP rules. Despite these differences, IMPA believes its wholesale forecast and its resource planning provide valuable insight into its long term resource needs, and IMPA will continue to work with the Commission on its planning efforts.*

Staff recognizes that IMPA's status as a wholesale utility imposes challenges not experienced by vertically integrated utilities such as Duke or I&M. Nevertheless, given the potential for EE and the rapid technological changes occurring at the distribution and retail customer level, it is imperative for IMPA to resolve data acquisition issues with its members so that its ability to carry out effective long-term resource planning on its members' behalf is not adversely affected.

Wabash Valley Power Association

According to the IRP, WVPA and its member cooperatives have been offering energy efficiency programs to the residential and commercial and industrial classes since 2012. These programs are briefly described on pages 18-20 of Section II. A table on page 20 shows the "planned energy efficiency and demand-related savings through 2016."

Almost nothing more is said in the remainder of the IRP document on energy efficiency. As noted above, it is not clear how or even whether the impacts of energy efficiency are captured in the load forecast. Energy efficiency is not mentioned in Section IV of the IRP which covers the selection of resource options. Neither is energy efficiency mentioned in the Base Resource Plan discussed in Section IV, pages 10 and 11. Lastly, the three year plan discussed in Section V, pages 8 and 9 only says "Wabash Valley will continue to coordinate nine residential and six commercial/industrial EE programs."

In reply comments (page 2), WVPA makes the point that energy efficiency is captured in the load forecast to the extent it impacts historical load data. They go on to say a statistically adjusted engineering model was used to estimate the residential average use model which included lighting assumptions. According to WVPA their energy efficiency programs are not specifically captured in the forecast since the programs have only been in place since 2012. As they gather more data on these programs, WVPA says it will determine the best way to incorporate them into the forecast.

Conclusion

All four IRPs failed to evaluate energy efficiency and supply-side resources in a consistent and comparable manner. As noted earlier, what *consistent and comparable* means exactly is an area open to debate. What is not open to debate is that utilities must endeavor to carry-out such an analysis. It is clear, however, that all four utilities failed to satisfy this requirement.

B. Requirement – Demonstrate how the preferred resource portfolio balances cost minimization with cost-effective risk and uncertainty reduction.

<u>170 IAC 4-7-8 Resource integration</u>

<u>Authority: IC 8-1-1-3</u>

<u>Affected: IC 8-1-8.5; IC 8-1.5</u>

(b) From its candidate resource portfolios, a utility shall select a preferred resource portfolio and provide, at a minimum, the following information:

….

(7) Demonstrate how the preferred resource portfolio balances cost minimization with cost-effective risk and uncertainty reduction, including the following.

(A) Identification and explanation of assumptions.

(B) Quantification, where possible, of assumed risks and uncertainties, which may include, but are not limited to:

(i) regulatory compliance;

(ii) public policy;

(iii) fuel prices;

(iv) construction costs;

(v) resource performance;

(vi) load requirements;

(vii) wholesale electricity and transmission prices;

(viii) RTO requirements; and

(ix) technological progress.

(C) An analysis of how candidate resource portfolios performed across a wide range of potential futures.

(D) The results of testing and rank ordering the candidate resource portfolios by the present value of revenue requirement and risk metric(s). The present value of revenue requirement shall be stated in total dollars and in dollars per kilowatt-hour delivered, with the discount rate specified.

(E) An assessment of how robustness factored into the selection of the preferred resource portfolio.

<u>Duke Energy Indiana</u>

Duke uses the System Optimizer and Planning and Risk models from Ventyx. System Optimizer is a resource planning model that is used to find the options with the lowest Present Value Revenue Requirements (PVRR), which is the primary standard upon which the various resource plans are judged. Planning and Risk is a production cost model that is used to find the costs associated with a specific resource plan under a given scenario.

Duke started by defining three scenarios (Reference, Low Regulation, and Environmental Focus) in consultation with the stakeholders. These scenarios are intended to be internally consistent in that the assumptions are tailored to fit the narrative of the scenario. The scenarios differ primarily in terms of the impact of future environmental regulations.

Next, a retire/retrofit analysis was performed for each scenario. The retirement analysis was performed using the Planning and Risk production cost model in addition to a spreadsheet that calculated the corresponding capital costs.

In the retirement analysis each generation unit is assigned a project list that ensures compliance with anticipated regulations. The estimated costs of these projects and their impacts on unit operations are determined. The most at-risk generation units are evaluated first and the decision to retire or control a unit is then used as an input for the next retirement analysis. The hierarchy of units included in the retirement analysis is:

1. Gallagher 2 and 4
2. Wabash River 6 with the option for natural gas conversion
3. Gibson 5
4. Gibson 1 and 2
5. Gibson 3 and 4
6. Cayuga 1 and 2

A unique portfolio was then developed for each scenario using System Optimizer. The portfolio for the Reference scenario was called the Blended Approach Portfolio, the one for the Low Regulation scenario was the Traditional Portfolio, and the Environmental Focus scenario yielded the Coal Retires Portfolio. Each optimization included the retirement decisions previously described. The retirement decisions for each portfolio were locked-in or hardwired in each optimization.

The Planning and Risk model was then used to model all three portfolios in all three scenarios (a total of 9 runs). This provided a PVRR for each scenario/portfolio combination, which were then compared to see how each portfolio performed under the assumptions of the three scenarios. An expected value approach was applied to these results by assigning a spectrum of different probabilities to the scenarios. The probability of each scenario was allowed to change in 10% increments between 0 and 100%. For example, if the Low Regulation Scenario had a 10 percent probability and the Environmental Focus Scenario had a 30 percent probability, then the Reference Scenario would have a 60 percent probability. This was used to show under what conditions a particular portfolio was either least or highest cost. The results are presented in Figures 8-F and 8-G on pages 126 and 127. It should be noted that while this approach is useful for comparing the three specific portfolios, it can give a false sense that a particular portfolio is "best" across a wide range of scenarios. There could be a fourth portfolio that is not optimal under any of the three defined scenarios but is better than any of the others across a wide range of the intermediate combinations of scenarios.

Individual sensitivities were run across each scenario for CO2 costs, load growth, renewable standards, capital costs, gas prices, and coal prices. These sensitivities generally consisted of an alternate low and high value. For the case of the load growth and renewable standard sensitivities, it would be necessary to change the resource mix in the portfolio (either because the amount or type of resource would change). Duke does not explain in the IRP the methodology for making those adjustments. In Reply Comments, Duke clarified that for sensitivities that would cause a change in the net load to the utility and, as a result, the resource plan, System Optimizer was used to develop the modified portfolio and to determine the costs of those portfolios in each of the three scenarios.

Issues Regarding Duke's Analysis

In their Reply Comments, Duke clarified that at risk units in the retirement analysis were those whose capacity value and net operating benefit might not cover their respective fixed costs and capital improvements (page 5) and that the specific retirement question was posed in years when there was the possibility of significant capital investment. The case-by-case retirement decisions were analyzed using the Planning and Risk production cost model in addition to a spreadsheet for calculating capital costs. These retirement decisions were then hardwired into the resource optimization model (Duke Reply, page 5).

Staff generally supports Duke's unit by unit retirement analysis and agrees that it can provide additional insights into retirement decisions that might not be available if the Optimization Model alone had been used (Duke Reply, page 5). But the question is not one of either using the optimization model or not. Rather it is using one type of analysis to inform and complement the other form of analysis. There is a possibility when you separate the retirement decision from the new resource decision that the hardwired retirement decision will dictate the new resource selection in the optimization model. For example, one can envision a situation where the retirement screen says to keep a unit online because the cost of retrofit is less than the expected benefit, but there could be a better option that gets shut out in the optimizer model because the retrofit costs are now sunk. This is the type of question that can be better addressed by the optimization model. Duke should have also allowed the optimization model to make the retirement vs. retrofit decision. A comparison of the retirement decisions coming out of the optimization model with the unit-by-unit analysis conducted by Duke would have been particularly useful. This is especially the case if the results differed. Attention could then be focused on understanding what is driving the different results.

Another area that could be improved is scenario development. Duke included scenario analysis to increase the robustness of the planning process. Consideration of a range of internally consistent views of the future was used to inform the development of what is hoped will be a robust portfolio. Duke then used the scenarios to create optimized portfolios, each of which could be evaluated under a range of possible futures. Sensitivity analysis was used as another level of analysis to see how a specified portfolio was affected by changes in selected key variables.

It is staff's opinion that Duke's use of scenarios for the first time in this IRP is an improvement over the previous reliance in the 2011 IRP on numerous sensitivities to develop a resource portfolio. The development of well thought out scenarios with divergent views of the future can provide considerable insight into how resource decisions might evolve if circumstances change significantly over the forecast horizon.

However, Duke's analysis was limited to the development of three resource portfolios whose performance was modeled under each scenario and a number of sensitivities. Also, the use of different probabilities for each scenario was informative by providing insight into the relative costs of each portfolio in an unpredictable world. Nevertheless, the usefulness is limited since there could be a fourth resource portfolio that is not optimal under any given scenario but performs best over a wide range of circumstances.

Staff thinks Duke's uncertainty analysis would have benefited from the development of at least 5 very different internally consistent scenarios. More diverse scenarios can be useful to better understand how different futures impact decisions and focuses attention on ways to maintain flexibility. However, there is a limit to how many scenarios can be used effectively; beyond a certain point there will be diminishing returns and the ability to derive useful information is reduced. How many scenarios is enough depends on how well the scenarios are designed and whether they reflect a sufficient range of possible futures.

Thorough long-term resource planning needs to consider both those futures that the planner views as probable or likely and those potential futures that are possible but not likely given what we know today. For it is the perceived unlikely or low probability events that can become tomorrow's reality that can have significant implications when making long-lived resource decisions. This is particularly the case when it comes to future environmental compliance costs that might be necessary for existing baseload fossil fuel units.

The CAC et al in their comments on Duke's IRP devoted much useful attention to the issue of coal plant economics (pages 2-12). They concentrated on the implications of the uncertainty surrounding environmental compliance costs and the timing of these investments in making decisions to retire generation facilities. In their Duke IRP comments (page 3) the CAC et al noted that Duke partly justified its CO_2 cost assumptions on the "belief that to be potentially politically acceptable, climate change policy would need to be moderate." This is an example of letting beliefs about what is most likely or currently acceptable perhaps drive the planning process rather than letting what is possible be determinative. Our purpose is not to debate specific CO_2 cost assumptions, but to emphasize that when thinking about risks and uncertainties in any long-term resource plan the focus must be on both probable futures and unlikely yet possible futures.

<u>Indiana Michigan Power Company</u>

I&M uses the LP long-term optimization model from *Plexos* to find the resource portfolio with the lowest current present worth revenue requirement (CPWRR). According to I&M, the LP model finds the optimal portfolio of future capacity and energy resources, including DSM additions that minimizes the cumulative

CPWRR of a planning utility's generation-related variable and fixed costs over a long-term planning horizon.

When analyzing portfolio performance for scenarios and sensitivities, Revenue Requirement at Risk (RRaR) is used as the standard. RRaR is defined as the Revenue Requirement for the 95th percentile revenue requirement minus the median (or 50th percentile) revenue requirement.

I&M starts with three long-term commodity pricing scenarios. Although the commodity prices include CO2, generation capacity prices, coal prices for Illinois Basin and Powder River Basin, natural gas prices, and peak and off-peak AEP-PJM hub electric prices; the primary differences between the three scenarios are the long-term prices of natural gas and coal. CO2 prices are identical for all three scenarios. The AEP Gen Hub capacity price projection does have some variation between scenarios, but the relationships between the scenarios are counterintuitive. For instance, the Base case price is lower than both the Lower Band and the Higher Band prices from 2017-2029. No explanation for this is provided in the IRP.

I&M used the *Plexos* LP model to develop two optimized portfolios based on two load forecasts (old and new). The new load forecast indicates lower load levels than the old forecast. Each optimized forecast was developed using the base commodity forecast. They also included eight resource portfolios that were developed by stakeholders in an exercise in the stakeholder engagement process. Each stakeholder portfolio was developed in an ad hoc manner by the participants and the sole criterion used was that the portfolio had to satisfy the reserve margin criteria each year through 2030. The stakeholder portfolios were based on the old forecast, so a direct comparison of those portfolios to the new forecast optimized resource portfolios may be misleading.

Using a production cost model to simulate the operation of the I&M utility system, the ten portfolios were evaluated using the three commodity forecasts and the new load forecast. Not surprisingly, the optimized plan for the new load forecast had the lowest CPWRR under all of the commodity pricing scenarios.

I&M acknowledged that the manner in which distributed resources were modeled likely had a negative impact on their selection in the optimization model. Distributed resources were modeled at their cost to I&M which is the full net metering rate. They then adjusted the optimized portfolio developed under the new load forecast to include distributed generation. This new portfolio is called the Preferred Portfolio and was developed "*to address what is likely to occur, in terms of customer adoption of distributed solar* *resources*." Distributed solar is added to the resource portfolio starting in 2016 and by 2033 over 153 MW (nameplate) of solar are added to the customer side. No further explanation as to why the solar resources were added, the timing of these additions, and the aggregate amount added over the planning horizon was provided.

I&M used a Monte Carlo simulation with 100 iterations based on four factors (natural gas cost, coal cost, power prices, and demand) for purposes of risk analysis. The historical relationships (correlation coefficients) among the four factors are provided. The Monte Carlo simulation can be done with independent draws for all four factors (ignoring the relationships among the factors) or with draws that use the correlations (so that a high natural gas price draw will affect the power price). Based on the discussion on page 185, it appears that the draws utilized the correlations. It is uncertain what type of distribution was used for the draws. It could be one where all values have an equal probability or one where the values near the base projection have a higher probability than the values at the extremes. The choice of the distribution will impact the results of the simulation.

The Monte Carlo simulations were used to find a distribution of revenue requirements for each of the eleven portfolios. The idea is that the distribution of possible outcomes provides some insight as to the risk or probability of a high CPWRR relative to the expected outcome. Those distributions were then used to determine the portfolios' RRaR. The larger the RRaR, the greater the level of risk customers would be subjected to if adverse outcomes occur relative to the Base Case CPWRR.

I&M concluded that the differences in RRaR between the portfolios are not significant. However, they did note that the addition of energy efficiency and solar generation, both distributed and utility scale, reduced revenue requirement risk. Also, those portfolios that have both Rockport units exhibited higher risk than the stakeholder portfolios that diversified by using natural gas, nuclear, renewables, or demand-side measures.

I&M noted that it is critical to view the risk analysis in the context of the overall cost. Figure 8C-5, on page 189, shows the CPWRR values for all 100 runs for each of the portfolios. The New load Optimized portfolio has not only the lowest expected cost, but it also has the lowest cost in 98 of 100 risk iterations.

Based on this risk analysis I&M concluded that a non-optimized resource portfolio, its "*Preferred Portfolio,*" was best. I&M believes the Preferred Portfolio represents a reasonable combination of expected costs and risk relative to the cost-risk profiles of the other portfolios.

Lastly, while CO2 prices were not varied in the initial commodity pricing scenarios or for the Monte Carlo simulations, a separate sensitivity analysis was performed on CO2 costs. The base analyses were performed using a $15/metric ton cost beginning in 2022. For the sensitivities, a low case with no (or zero) CO2 cost and a high case of $25/metric ton (also beginning in 2022) were performed. It is unclear whether the sensitivities were performed for all of the portfolios or only for the Preferred Portfolio. While I&M notes that the high CO2 sensitivity does not affect the viability of the Rockport units, this could be a result of the high price not being high enough to change the result. More should have been done to explore what level a CO2 price caused the Rockport decisions to change.

Issues Involving I&M's Analysis

I&M only has two portfolios that are based on their current load forecast - the optimized portfolio based on the new load forecast and the Preferred Portfolio that is an adjusted version of the other portfolio. Thus, there is little to no direct comparison of the performance of different portfolios under different scenarios. While some amount of comparison can be observed based on the portfolios using the old load forecast, the usefulness of those comparisons is limited. There is only one optimized portfolio based on the old forecast; the others were done on an ad hoc basis by the stakeholders with little to no information on the costs associated with different options.

Preferably, I&M would have first developed a range of scenarios based on distinctive possible futures. Then an optimal resource plan would have been developed for each scenario, and each of these plans would have been subjected to stress testing such as that performed using Monte Carlo analysis. I&M instead really only had two scenarios for which optimal resource plans were developed, and the only difference between the two scenarios was the load forecast. It is a stretch to consider these as distinctly different scenarios.

The choice of the "Preferred Portfolio" is less than clear. As is noted in other places in this document, the inclusion of over 150 MW of DG solar in the preferred resource plan is not the result of an optimized portfolio using *Plexos* but appears to be ad hoc in nature. Also, the optimized portfolio based on the new load forecast has the lowest expected costs in 98 of 100 risk iterations. The New Load Optimized Portfolio compared to the Preferred Portfolio has a lower Base Pricing CPWRR and the RRaR is virtually the same according to the information in Figure 8C-4.

I&M's planning reflected in the IRP suffers from a number of other unnecessary self-imposed limitations that indicate an unwillingness to thoroughly explore risks and uncertainties or a misunderstanding of what the IRP process is supposed to do.

The CAC et al note (on I&M's IRP, page 23 and comments on draft report, page 8) I&M's consideration of the costs of carbon regulation and carbon prices is not as thorough as it could have been. The Company position is as follows:

> *The underlying reason for this assumption is that a CO2 cost cannot be so onerous that it "shuts in" a significant portion of the nation's generation fleet. Scenarios with untenably high CO2 prices simply mean higher power prices, not universal coal retirements. Very efficient coal plants, such as Rockport, will continue to dispatch as baseload.*

The Company goes on to say in its Reply Comments that "*a carbon price that would cause, specifically, the Rockport units to sit idle is not a realistic carbon price proxy.*" (page 9) Staff believes that this misses the point. One purpose of an IRP is to explore what is probable or realistic, but a larger purpose is to explore those things that do not seem plausible today but could happen. As I&M notes in its reply comments regarding potential greenhouse gas regulations (page 16), "*no one knows how such regulation will impact I&M's existing coal-fired sources*" nor does anyone know "*what cost, if any, will be assigned to CO2 emissions.*" (page 17) Uncertainty analysis is supposed to explore these circumstances to help decision makers better understand the potential consequences, both favorable and not, of alternative resource decisions.

Limited analysis of CO2 cost fails to allow proper consideration of how the impact of other environmental compliance costs interact and combine with possible CO2 costs when developing alternative resource plans. As I&M notes in its Reply Comments (page 18) with respect to SO2 National Ambient Air Quality Standards, "*the timing and extent of any potential remediation by I&M is uncertain*." Similar comments could apply to other future environmental regulations. For example, what is the impact of moving forward the addition of FGDs at the Rockport Plant from the late 2020s, both with and without various CO2 regulation assumptions? It is precisely the combination of uncertainty surrounding CO2 and other environmental regulations and its implications that is the foundation for much of the CAC et al's useful critique of I&M's IRP.

Indiana Municipal Power Agency

IMPA uses a number of modules from Ventyx's software. Market analysis is done with the Horizons Interactive module, portfolio development is performed with the Capacity Expansion module, and the MIDAS Gold module is used to perform portfolio analyses. The primary standard for analyzing various plans is Average System Rates (ASR).

A key input to the development of an IRP is a reasonable projection of the future cost of market power and energy. The Horizons Interactive module was used by IMPA to solve zonal energy and capacity prices for large geographic regions, at a minimum the entire Eastern Interconnection. IMPA was primarily interested in forward energy and capacity price curves for five market zones where it has resources and load. The zones are MISO-Indiana, MISO-Iowa, MISO-Illinois, PJM-AEP, and PJM-DEOK.

The Capacity Expansion Module is an optimization screening tool that examines different combinations of new generation resource additions, unit retirements, and demand-side management programs. Once the forward price curves are developed by the Horizons Module and alternative optimized resources are developed by the Capacity Expansion Module, Midas Gold is used for production cost modeling and the development of revenue requirement projections.

IMPA used the Horizons Interactive market module to develop a number of zonal electricity price projections for hourly energy and monthly capacity. Fifty futures were developed by using Monte Carlo simulation draws from 30 scenarios addressed by the Energy Information Administration in its 2012 Annual Energy Outlook. The Horizons Interactive module was run for each of the 50 futures, resulting in a range of market prices.

IMPA defined four scenarios based primarily on environmental considerations. The Green Revolution scenario has the strictest environmental rules and the Retrenchment scenario has the most relaxed rules, while the Reference and Shifting Gears scenarios fall between the other two.

Ten distinct portfolios were developed using the Capacity Expansion module based on different combinations of assumptions and restrictions. The distinctions between portfolios are based on the level of energy efficiency, the load forecast, the amount of renewables, the build vs. buy option, and the retirement of the Gibson 5 unit.

The 50 futures developed earlier were used with the MIDAS module to perform a Monte Carlo simulation of each of the ten portfolios. As a result, each portfolio was modeled 51 times – 50 using the Monte Carlo futures and one using a "deterministic" scenario. IMPA then created a risk profile for each resource plan by graphing along the x-axis the Levelized Average System Rates (cents/kWh) for each of the 50 futures and the deterministic scenario. The y-axis is the cumulative probability of the occurrence of each outcome between 0% and 100%. According to IMPA, if the far left point is 7.6 cents/kWh and the far right point is 9.25 cents/kWh then there is a 100% confidence that the rate will be between those two points. A narrower range is supposed to indicate less risk.

For each portfolio, an expected ASR (using the Reference scenario and labeled the "deterministic" solution) was found, along with a distribution of 50 stochastic rates from the Monte Carlo simulation. The average of the 50 stochastic outcomes is calculated. IMPA measures the overall risk of a resource portfolio as the difference between the deterministic levelized rate and the average stochastic levelized rate. Also, the contribution of different factors (such as capital costs, load, electricity prices, and fossil fuel prices) to up-side and down-side risk is provided.

IMPA also determined the ASR for each of the ten portfolios under the scenarios developed previously. This allows a performance comparison of the ten portfolios for each scenario.

Notes and Comments

IMPA used various measures of risk. For example, IMPA presents the expected cost-risk trade-off in Figure 113 on page 12-154 which is barely mentioned. This bar chart displays for each of the ten resource plans the highest, lowest, and expected values of ASR developed from the stochastic analysis. I&M also presented risk using an ASR efficient frontier graph which provides a measurement of risk versus the levelized ASR. The measure of risk appears to be the standard deviation of the ASR. Points closer to the origin have both a lower levelized ASR and lower risk.

To better understand the risk of various drivers of ASR, IMPA used tornado charts to determine the sensitivity of ASR to different drivers. The lengths of the bars show the impact of each independent variable on ASR. The longer the bar, the greater the impact on ASR. The results for the ten plans consistently demonstrate that the price for CO_2 emissions, natural gas prices, and coal prices are the largest drivers of ARS.

Despite the development of the tornado charts based on stochastic futures and the use of four scenarios with different commodity and CO2 prices, there is little notion of how this information was used to evaluate the risk from substantially different natural gas or CO2 prices. On page 13-166 in a section that discusses risks and uncertainties, IMPA recognizes potential CO2 legislation and various commodity prices as the single largest risk drivers. But nothing more is said. On the very same page, IMPA addresses the value of flexibility in its plan selection. Page 13-163 explains how their preferred plan has the flexibility to evolve into other plans as future conditions warrant.

The optimization process was basically limited to selecting from a small number of supply-side resources. Energy efficiency resources are hardwired in the development of the 10 resource plans used in the uncertainty and risk analysis. Demand response and DG resources were not considered in the model.

IMPA in its Reply Comments (pages 4 & 5) disagrees with the characterization of the resource optimization being limited to a small number of supply-side resources. They note that consideration of seven traditional generation options, five renewable options, and the retirement of all IMPA's existing generation facilities in each year of the planning horizon does not equate to a small number of supply-side resource options.

Nevertheless, the demand-side of the resource choices normally included in an IRP was inadequately addressed and this weakens the results of IMPA's analysis described above. Not being a vertically-integrated utility has clearly impacted IMPA's IRP and adds some complications in evaluating the reasonability of IMPA's IRP. IMPA does not normally interact with their members' retail customers and IMPA does not have any authority over distribution (including demand response, energy efficiency, and customer-owned generation). The lack of authority over the distribution system also means that IMPA does not have ready access to the quality and quantity of information about retail customer behavior that is available to an integrated utility such as DEI or I&M.

The implications of this limitation are seen throughout the IRP; especially load forecasting, energy efficiency, demand response, distributed generation, and resource optimization. Rapid technological changes are being seen at the distribution and retail customer level – including DG, DR, energy efficiency, and the smart grid – which means that IMPA must strive to better understand how these changes will impact their resource requirements over time. IMPA, to its credit, recognizes this is increasing in importance but much greater efforts will be necessary for it to conduct thorough resource planning in the future.

Wabash Valley Power Association

WVPA created nine scenarios for analysis using a combination of three member energy forecasts and three sets of market price projections. The market price projections are based on a wide range of natural gas and coal prices. A tenth scenario includes CO2 prices in the base scenario (CO2 costs are not included in the other scenarios).

WVPA used MIDAS to find the production cost impact of each scenario. Individual scenario results are not provided. The highest and lowest cost scenarios are presented on a percentage of the base scenario basis.

Alternate expansion plans are developed for the high and low load growth forecasts. WVPA does not evaluate how alternate expansion plans perform under scenarios other than the ones for which they were constructed.

Comments and Questions

WVPA says that analysis is performed to evaluate risk, reliability, and cost impact to its members (Section IV, p. 10). But the information presented in Sections IV and V of the IRP report fails to demonstrate that this is the case. There are a number of limitations:

1. A capacity expansion optimization model was not used to develop resource plans that were then subject to further analysis. WVPA generally evaluates opportunities as they arise and their current process allows them to screen opportunities as they arise (WVPA Reply Comments, Page 3)
2. It is not clear how the Base Resource Plan was developed. It appears that modeler judgment was the primary means, but this is not clear in the IRP. According to Reply Comments, WVPA's base resource plan was developed by modeling multiple plans against the base forecast when capacity shortages exist (page 3).

3. A resource plan was developed only for the Base and High and Low Economic Growth scenarios. In Reply Comments WVPA said market price changes have a minimal effect on their need for new resources (page 3).
4. The Base Resource Plan was the only capacity expansion plan modeled using the nine scenarios.
5. WVPA says in the IRP that it contracts with ACES to provide risk management functions, including stochastic modeling. Based on information in WVPA's Reply Comments, ACES provides WVPA on a monthly basis a three year forecast and analysis of the key components of WVPA's portfolio using ACES' stochastic model. But WVPA does not utilize the ACES stochastic model for long-term resource planning.

There is a statement in Section IV on page 10 that is not substantiated with any information presented in Sections IV and V:

> *Even though the majority of our scenarios identified simple-cycle combustion turbines as the best way to meet our short term and intermediate term capacity needs, it was not always the definitive answer to our capacity needs and risk portfolio. In many situations, natural gas fired combined cycle plants resulted in lower costs and risk for our Members. Wabash Valley has decided to use CTs prior to 2027 as the base case for our IRP; however, a small change in assumptions and market conditions would specify combined cycle plants as the preferred resource to meet future needs*.

This statement indicates that WVPA performed more and different types of analyses which were not discussed in the report.

In Reply Comments (page 5) WVPA had the following response:

> *WVPA evaluated multiple expansion plan options using various combinations of CTs and combined cycle (CC) units. These various options were evaluated against our base load and market price forecast under the following assumptions:*
>
> - *Without excess generation sold into the market*
> - *Without any market interaction (sales or purchases)*
> - *With market interaction*

We chose these conditions to help gauge the various plans reliance on the forecasted energy market. Without market sales, CTs more often than not proved the better option. With market sales, CCs more often than not proved the better option. WVPA chose CTs as its capacity solution for this IRP based on past market price volatility, but small changes in the energy market result in CCs being the better option for our members.

This additional information is helpful but does not offset the lack of information presented in the IRP.

WVPA's analysis has a number of limitations. Chief among these is the confusing manor in which the analysis was presented in the IRP. Too little space was devoted to explaining fully the modeling process and presenting the results with adequate discussion so that a reader can be confident they understand what was done and why. Failure to use a resource optimization model also raises questions about the adequacy of the planning that was performed. A more structured and thorough presentation of the modeling and analysis that was performed would be helpful but cannot offset the failure to use state of the art resource planning tools.

C. Requirement – A discussion of distributed generation within the service territory and the potential effects on generation, transmission, and distribution planning and load forecasting.

<u>170 IAC 4-7-4 Methodology and documentation requirements</u>

Sec. 4 (b) (5) A discussion of distributed generation within the service territory and the potential effects on generation, transmission, and distribution planning and load forecasting.

<u>Duke Energy Indiana</u>

The discussion of distributed generation (DG) in the IRP is minimal and DG is not explicitly modeled in the resource portfolio development exercise except to satisfy a minimum level of renewable generation for each scenario. Customer self-generation is discussed in two short paragraphs on page 31 in the load forecast chapter. There Duke says no additional cogeneration units that impact the load forecast are assumed to be built or operated within the Duke service territory over the forecast period. Duke goes on to say the renewables or EE categories in this IRP can be considered placeholders for any new cogeneration projects.

Non-utility generation as future resource options is discussed on page 69. Duke states a customer's decision to self-generate or cogenerate is based on economics and that such projects are generally uneconomic for most customers. As a result, Duke says it does not attempt to forecast specific megawatt levels of this activity. It is argued that cogeneration facilities that are built affect customer energy and demand and are captured in the load forecast. Again, Duke says that portions of the projections for renewables and EE in the IRP can be viewed as placeholders for these types of projects.

Utility scale solar is discussed at the bottom of page 74 and continuing to page 75. Screening curves are developed for 150 MW wind and 25 MW solar PV. The renewables technologies considered in the resource portfolio optimization model are solar, wind, and bio-methane. Wind is modeled in 50 MW blocks, solar in 10 MW blocks, and bio-methane in 2 MW blocks. According to Duke, solar is the least expensive but has a 20% capacity factor and has a slightly greater contribution at system peak than does wind. Wind is a close second in cost-effectiveness but its intermittency, especially during peak periods, is a concern. Biomass is recognized by DEI as being a baseload generation option and is dispatchable, but is higher cost than wind.

Duke believes it is prudent to plan for a Renewable Energy Portfolio Standard (REPS) so each scenario included a REPS. The Reference Scenario assumed a mandated REPS with minimum levels of 1% of total retail energy sales by 2020 and 5% of total sales by 2033. The Low Regulation Scenario has a REPS of 1% of sales by 2020 and 4% by 2033. There is a 1% REPS in 2020 and 15% by 2033 for the Environmental Focus Scenario.

The Traditional Portfolio has 109 MW solar, 35 MW wind, and 12 MW biomass; the Blended Portfolio has 139 MW solar, 178 MW wind, and 14 MW biomass; and the Coal Retires Portfolio has 265 MW solar, 173 MW wind, and 27 MW biomass.

There are a number of issues with Duke's treatment of renewable energy and DG in the IRP:

1. Duke believes the effect of customer-owned generation is reflected in the load forecast. But it does not indicate how this is modeled, especially when technology is changing rapidly and the costs of renewable energy and DG are falling steadily.

2. Duke does not discuss how technological change is causing the cost of DG to fall significantly and how customer attitudes are changing toward the ownership and use of DG facilities. What

might the implications be for the utility and how might its resource portfolio change should these circumstances become more pronounced? A thorough discussion and analysis of this topic would have been helpful.

3. Duke might have said more about their rationale that the customer's decision to install distributed generation of any type is merely a function of, apparently, the current economics of distributed generation. Aside from the declining costs of solar, wind, and other distributed generation, Duke's argument seems to deny the possibility that some customers may want their own generation for their perception of benefits – cost and / or reliability; especially over the long-term planning horizon. It may be, for example, that home and office builders will start installing solar panels on new construction if they believe consumers have a desire for this feature. Schools – particularly universities – may be interested in micro-grid or other distributed generation for its educational value in addition to potential cost savings and reliability benefits.

To the extent the effects of customer-owned generation are not reflected in the load forecast, Duke says the projections for EE and renewable energy can be viewed as placeholders for DG resources. Again, it is not obvious that this is the case given the rapid changes in technology and falling cost for DG.

Duke's Reply Comments further confuse the matter as to what was modeled regarding DG:

> *Duke Energy Indiana's load forecast captures the projected impacts of customer sited solar in the residential and commercial sectors. In order to develop the outlook for customer sited solar, general assumptions were made with regard to technology costs and tax policy. The final MWH sales and MW peak forecasts are slightly lower due to the inclusion [of] solar distributed generation*. (DEI Reply Comments page 10)

This clearly indicates that DG was included in the load forecast model, but too little information is presented in the IRP and Duke's Reply comments to understand what was done and how.

Duke goes on to say in Reply Comments (page 10):

> *For the Base forecast, the load forecasting process does not factor technology improvements in excess of what it [sic] embedded in the historical data and in the future values of predictor variables such as income per capita, employment and manufacturing GDP. It is not possible to*

forecast incremental improvements in technological innovation. Finally, it can be argued that the likelihood of sales increasing or decreasing due to overall improvements in technology is similar.

Staff agrees that projecting technological improvements and how customers respond to these improvements is, at best, extremely difficult and uncertain. But we also think it is this difficulty and uncertainty that warrants careful thought and consideration in any integrated resource planning process. Some analysts, rather than ignoring the potential increases and concluding it's too difficult to estimate, use "learning curves" as a proxy of the adoption of new technologies. As with other important elements of the IRP, Duke might have used more generous assumptions that were within the realm of reason to better assess the risks of uncertainty and the potential ramifications for their long-term resource planning.

Indiana Michigan Power Company

The purpose of this section is to primarily discuss how I&M modeled distributed generation (DG) in the IRP modeling exercise, but we will also touch on some aspects of how utility scale renewable energy was analyzed.

I&M notes that the cost of solar panels has declined considerably over the last decade and that various forecasts generally see declining nominal prices for the next decade (p. 125). They also recognize that distributed solar, often seen on rooftops, is also experiencing declining costs as associated hardware, such as inverters, racks, and wiring bundles become standardized. The result is that both distributed and utility scale solar projects will be more economical in the future.

Utility scale solar up to 50 MW per year of incremental nameplate capacity was made available to the *Plexos* optimization model for selection beginning in 2014. One assumes the installed cost for solar panels in Figure 5D-3 is reflected in the costs used in the *Plexos* model.

Distributed solar resources were modeled at their cost to the utility which I&M stated is the full retail net metering rate, not the installed capital costs.

I&M observes that the cost of electricity from wind generation is becoming competitive within PJM due in large part to subsidies such as the federal production tax credit and REC values. Wind resources are modeled as Purchase Power Agreements with costs at a constant real rate of $65 per MWh. I&M limits the implementation of wind resources to a "realistic amount," 100 MW, each year in the *Plexos* modeling. An assumption made by I&M is that the Federal Production Tax Credit will not be extended beyond 2013. Distributed wind was not modeled in developing this IRP.

Biomass and incremental hydroelectric resources were not considered in the modeling process.

<u>Results</u>

The presentation of the results of the optimization modeling and the development of the Preferred Portfolio is confusing.

On page 184, I&M says the optimization modeling process did not select any distributed solar even though their costs decline throughout the planning period. The costs referred to appear to be the installation capital costs although this is not made clear. According to I&M the reason for this is that the solar DG resources were modeled at a cost based on the full net metering rate. I&M also presents a Figure 4E-3 on page 93, duplicated in Figure 8C-2 on page 184, which presents four different lines on a graph:

1. A line representing Net Metering Payments
2. A line representing the PJM Value of Solar
3. A line representing Utility Scale PV with the Investment Tax Credit (ITC)
4. A line representing Consumer Scale PV with ITC

I&M describes this graph as showing the avoided cost value of a typical rooftop resource in relation to its net metering cost (p. 184). On page 92, I&M says, referring to the table on page 93, customer-sited DG costs the utility more than the PJM value it provides.

The presentation of the DG solar analysis is flawed because the reader has no means to understand what I&M did. The information presented in Figures 4E-3 and 8C-2 is described in one or two sentences and provides no information as to how the data presented was developed, the sources of the data, and the assumptions required to develop the data.

Given that I&M modeled DG solar using the "*full retail net metering rate*," it would have been useful to explain exactly what this rate included and how it was calculated. It would also have been instructive to perform an optimization using some different assumptions instead of only using the retail net metering rate.

As noted above, I&M developed two optimized portfolios using the base commodity forecast and two different load forecasts (Old and New). Table 8C-1 shows the summary capacity additions for the two optimization portfolios. The table indicates that 249 MW of utility scale solar is added in the period 2020-2033. The 249 MW is based on the PJM capacity value which recognizes 38% of solar nameplate MW capacity for ICAP purposes. This means I&M is projecting the addition of 700 MW of utility scale solar to be added over the period 2020-2033.

I&M then constructs a final "*Preferred Portfolio*" based on the portfolio optimized under the new load forecast. The Preferred Portfolio begins to add distributed solar in 2016 "*at a point that roughly corresponds to the cross-over point in value from the customer's perspective*." (p. 185) By 2033, 153 MW (nameplate) of DG solar are added on the customer side of the meter. I&M states '*this portfolio is identical to the optimized portfolio with the addition of over 150 MW (nameplate) distributed generation through the planning period that is thought likely to occur under current net metering compensation rules."* (p. 185)

The problem is that I&M added the solar DG because it was "*thought likely to occur*." So the solar resource additions appear to be ad hoc in nature and no more explanation is provided. The question of how I&M derived what it thought was likely to occur was not addressed.

Reply comments prepared by I&M (pages 12-13) also miss the point. I&M's comments focus on the costs to the utility of DG that is reflected in rates in its analysis. The real issue is how customers react to declining costs of installing and operating DG and what the implications for the utility are over a period of time. Clearly, how customers respond to these changes is affected by utility actions and regulatory policies. A discussion exploring this would have been most useful. Whether we like it or not, we are now in a world where more attention must be paid by utilities and regulators to how consumers respond to changes in technology, costs, rate structures, and numerous other utility and regulatory processes.

Indiana Municipal Power Agency

Distributed generation was not considered as an option in the resource plan development process beyond a brief general discussion of net metering and other retail customer-owned generation. IMPA knows of six net metering customers and IMPA has a contract with a commercial/industrial customer of one of its members to purchase excess generation from that customer's onsite generation facilities. The customer has been selling small amounts of energy to IMPA under a negotiated rate. There are no customers that operate a combined heat and power (CHP) system. Based on EPA data, IMPA is aware of 15 industrial boiler installations in IMPA member communities. Nothing is known by IMPA regarding the size or condition of these facilities. With the exception of emergency back-up generators at some hospitals, factories, and water treatment plants, IMPA says it is unaware of other non-renewable retail customer-owned generation in its members' service territories.

IMPA recognizes that, under the right circumstances, CHP systems would be beneficial to both the customer and IMPA, but notes that the operating conditions and economics must be in place for both parties if a CHP project is to go forward. They also state that most DG systems are small and would have little impact on the long-term. Nevertheless, IMPA declares it will work with their members and the members' retail customers to investigate the addition of CHP or renewable systems at customer locations (p. 11-128).

IMPA's discussion of DG is focused on what currently exists and not on how things might be in a few short years given the rapid changes in technology and costs, especially for solar. A more thorough discussion, at a minimum, of the possibilities and implications of greater penetration of DG would have been desirable.

IMPA included the following renewable alternatives in the resource expansion modeling:

1. Wind – Build (50 MW)
2. Wind – PPA (50 MW)
3. PV Solar (small facilities at member locations)
4. Bio Mass (25 MW)
5. Landfill Gas (2.5 MW units in sets of 10 MW)

Another section of the IRP report says a base case was developed that assumes 21 MW of solar park development over the next seven years. Additional renewable energy additions were left up to the expansion model to determine (p. 6-47).

The ten expansion plans discussed on page 11-132 include a base level of renewables or a high level of renewables. The IRP only says on this page that the two levels were previously discussed in the document. The discussion is not entirely clear about what the base and high levels of renewables are, but there is a strong impression that the renewable energy was hardwired in the optimization model. IMPA clarifies in Reply Comments (page 4) that renewables were included as available resource options in addition to the solar facilities that were hardcoded. They go on to say that no renewables were selected by the model due to economics. However, as with all planning models, the assumptions drive the results of the model. Assumptions that some might regard as being unduly conservative given the declining cost of some forms of distributed generation and the potential significant increases in the costs of other resources, may have limited the selection of distributed generation. As a result, IMPA's assessment of risk may be too restrictive to be beneficial to their member utilities and their customers.

Wabash Valley Power Association

WVPA discusses in Section II on pages 22-23 how it handles end-consumer DG, with emphasis on the interconnection process. WVPA states that any consumer-owned generator is factored into the IRP either through the inclusion of the resource as a generator or utilizing the generator to offset load as a behind the meter resource.

Landfill gas internal combustion generating units are discussed in Section II on page 10 where it is noted that WVPA has 44 MWs of landfill gas generation capacity and plans to add another 3.2 MW in 2014.

The section of the IRP titled "Selection of Resource Options" does not discuss DG or renewable energy. Nevertheless, the Base Resource Plan shows 32 MW of planned landfill gas generation being added through 2032.

The discussion of DG and renewable energy is minimal and provides no insight as to what WVPA thinks of these resource options, or how technological change and falling costs in this area might impact WVPA's resource needs going forward. Beyond landfill gas generation, it appears that WVPA gave no thought or consideration to the possibilities associated with the various DG and renewable resource options and how these possibilities might evolve given a range of potential future circumstances.

WVPA in Reply Comments presents information demonstrating its involvement in both DG and alternate energy. The table has four wind projects ranging in size from 8 to 21 MW, two landfill gas projects (one is 44 MW and the other 4 MW), a 1.4 MW digester project, and a 20 kW solar project.

WVPA did note on page 23 in Section II that the projection of peak demand and energy is adjusted as required to reflect the impact of consumer owned distributed generation, but WVPA fails to explain how it was done. In Reply Comments (page 6), WVPA says if a large customer is expected to add generation that will lower their load requirements, then WVPA will reduce the load forecast for that member cooperative to reflect the displaced load. The amount of peak and energy adjustment depends on the type of adjustment.

D. IRP Public Advisory Process Review[3]

Use of meeting facilitators

Both Duke and I&M used facilitators to keep the meetings on schedule while trying not to unnecessarily restrict conversation.

Meeting Registration

Both Duke and I&M used an on-line process to register attendees and to provide meeting materials.

Duke Energy Indiana

The Duke process seemed to produce a discrepancy between the meeting starting time on the printed agenda and the time shown on the on-line registration confirmation. The on-line registration confirmation for the 7-19-13 meeting shows a 9:00 a.m. registration and a 9:30 a.m. workshop start. A subsequent e-mail (reminder/follow-up) included the 8:30/9:00 times but did not state they were a change from the original times. The agenda used at the meeting had an 8:30 a.m. registration and a 9:00

[3] The Public Advisory Process only applies to investor-owned utilities, so only Duke and I&M were required to use this process.

a.m. workshop start. At least two attendees arrived at 9:15 a.m. to discover that the workshop had already started.

Indiana Michigan Power

There were no apparent problems with their process.

Number of Stakeholder Advisory Process Meetings

The Draft Proposed IRP rule requires a minimum of two meetings before the IRP document is provided to the commission. Two meetings are too few based on what staff saw with the Duke and I&M stakeholder advisory processes if the utility really wants to effectively seek stakeholder and public input in the development of the resource plan. There is too much material and information to be conveyed to an audience with varying levels of technical expertise. These thoughts are echoed by the feedback of one active participant (CAC et. al.'s Reply Comments, pages 1 – 3). Effective use of e-mail and placing informative material on a website can make the meetings more efficient, but this complements a meeting rather than substituting for a meeting.

Meeting to Meeting Transition

The utilities need to recognize that while their planners perform IRP work every day, many of the meeting attendees have not spent much time on the subject since the last meeting. They need to devote some time at the start of each meeting to orient new/returning participants to where they are in the process. For example, Duke had a couple of meetings where a customer showed up to see what is going on.

Meeting material should be made available at least one week before a public advisory process meeting so that stakeholders can more meaningfully participate. (CAC et al.'s I&M Comments, page 4) The meeting to meeting transition will also be facilitated if responses to stakeholder questions, comments, and suggestions from the previous meeting are addressed at the start of the next meeting. Responses should also be in written form and preferably made available when other meeting material is sent to participants, at least one week prior to the meeting. (CAC et al.'s I&M Comments, page 5)

Duke Energy Indiana

The Duke slide deck for Workshop Number 2 makes no mention of what happened in Workshop Number 1. The same can be said of the slide decks for meetings 4 and 5. Duke did a brief review of workshops 1, 2, 3 and 4 on slide 9 of Workshop 5.

Indiana Michigan Power

The I&M slide deck for Workshop Number 2 has a number of pages with follow-up items from Workshop Number 1, but no initial pages simply reviewing what happened at that first workshop. A participant who did not attend the first workshop was at a disadvantage.

The same can be said of the slide deck for Workshop Number 3.

Handling Non-Agenda Questions

The utilities should expect that questions will come their way that may not fit into the IRP collaborative process. The meeting facilitator(s) or someone else from the utility should be empowered to get the questioner's contact information for a response at a later date if one cannot be provided at the meeting.

Duke Energy Indiana

While Duke did not always handle questions well, they did try to answer them.

Indiana Michigan Power

Two questions came up at the first I&M meeting and the presenters from Columbus seemed to respond that the item was not on the agenda. No one from I&M stepped up to assure the questioner that someone would respond later. Possibly this was done at a break in the meeting, but it appeared I&M was unprepared for such questions.

Indiana Distributed Generation Landscape

The utilities should expect that proponents of DG will be participating in their collaborative. While utility planners often think in hundreds of MWs, the DG community is thinking of a 1 MW project as being large.

While the projects may not be in their service territory, the utility presenters should have some knowledge of DG projects in Indiana.

Duke Energy Indiana

In response to a question about biomass, the presenter discussed biomass boilers in North Carolina. He seemed to be unaware of the biodigester projects in this state.

Indiana Michigan Power

At the third session, I&M provided a listing of Customer Generation facilities Interconnected as of September 6, 2013, which helped address this issue.

The First Meeting Orientation to IRP

Access to confidential information needs to be addressed at the first meeting. Some participants will have the necessary background and ability to make effective use of the confidential information so their circumstances need to be recognized.

Also, the utilities need to think about making the stakeholder meetings accessible if people are unable to physically attend for whatever reason. Meetings whenever possible should be located in the utility's service territory so that customers are better able to attend. Use of technology such as webinars can make the meeting accessible to people who are interested but unable to travel to the service territory.

Duke Energy Indiana

Duke furnished pre-first meeting materials about renewables, energy efficiency, and draft IRP scenarios. Duke struggled for two or three meetings as to how to deal with confidential information. This was resolved by Duke and the stakeholders resolving the issue in a discussion separate from the regular stakeholder meetings. After a couple of meetings, Duke made good use of webinar technology.

Indiana Michigan Power

I&M had participants at each table use a spreadsheet model to develop a preferred plan based on a need for new capacity over the planning period. How effective this approach was as an introduction to integrated resource planning is difficult to gauge. Some folks struggled just to use the model. It may have been just as effective to introduce various plans: 1) No new coal, renewables only; 2) No new coal or gas, renewable only, etc. I&M spent time determining a PVRR for each plan and comparing them to the ultimate preferred plan. It is not obvious it was a bad idea; but there may be better alternatives. (see slide #12, workshop #3)

Utility Responses to Stakeholder Feedback

Utility companies need to devote the resources necessary to respond to stakeholder feedback, comments, and suggestions. This involves developing a process to track stakeholder issues and to document how the utility responded. If stakeholder feedback is incorporated in the IRP then the utility needs to be clear how and where the input was reflected in the IRP modeling process. (CAC et al's Comments on 2013 Draft IRP Report, pages 2-3) Written responses should be provided at least one week prior to the next meeting and avoid unnecessarily cryptic answers. (ibid.)

Duke Energy Indiana

In Workshop 4 Duke's slides 14, 15, and 16 discuss their responses. They also provided a document with responses to 43 stakeholder concerns.

Indiana Michigan Power

I&M discussed on pages 30-32 of the IRP the relevant stakeholder issues raised during the public advisory process.