DRAFT REPORT

OF

THE INDIANA UTILITY REGULATORY COMMISSION

ELECTRICITY DIVISION DIRECTOR

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REGARDING 2013 INTEGRATED RESOURCE PLANS

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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 proposed rule, the electricity director shall 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 report to the informational, procedural, and methodological requirements of the rule. The proposed rule goes on to say in section 2(l) that the draft report shall not comment on the utility's preferred resource plan or any resource action chosen by the utility.

Four Indiana utilities submitted integrated resource plans 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

For purposes of preparation of this report, the commission has decided to act as if the proposed rule is in effect. This draft report was written to comply with the requirements specified above.

Supplemental or response comments may be submitted by the utility or any customer or interested party that earlier submitted written comments on the utility's IRP. Supplemental or response comments must be submitted within 30 days from the date the director issues the draft report. The director may extend the deadline for submitting supplemental or response comments.

The director shall issue a final report on the IRPs within 30 days following the deadline for submitting supplemental or response comments.

Indiana Michigan

Load Forecast Methodology

I&M's load forecasting methodology appears to be reasonable and sound overall. However, there are a number of questions left unanswered.

Forecasting Methodology

The IRP report states that I&M uses two different econometric models to forecast energy requirements:

- a set of monthly short-term models, and
- a set of long-term models

For the first full year of the forecast, the forecast is generally based on the short-term models. The short and long-term forecasts are blended during the first six months of the second full year of the forecast.

The short-term models use mostly trend, seasonal, and weather variables since short-term electricity consumption is assumed to be a function of a fixed stock of equipment. Residential and commercial classes are mostly affected by weather. The industrial customer class is mostly affected by inventory levels and factory orders.

The long-term forecasting models employ a range of structural economic and demographic variables, electricity and natural gas prices, heating and cooling degree-days, and binary variables.

The report contains an extensive discussion of the short-term models and the blending process used to transition from the short-term to the long-term forecast only to abruptly state (on page 47) that for Indiana they only use the long-term models. The explanation given by I&M is that reliance on only the long-term model best utilizes the long-term methodologies' capability to anticipate turning points in economic growth. The result is a number of unanswered questions:

1. Why have a detailed discussion of the short-term models if the models are not used for Indiana?
2. The explanation given about better anticipating turning points in economic growth is both vague and confusing. Are long-term load forecasting models normally used to forecast changes in economic growth?
3. Are the short-term models estimated separately for the Indiana and Michigan service territories like the long-term models are?
4. Was a blended forecast used for Michigan? If yes, why the difference in treatment between Michigan and Indiana?
5. Did I&M use the blended forecast in the 2011 IRP? If yes, what changed between 2011 and now to warrant this change in the 2013 IRP?
6. I&M states on page 54 there have been some changes to the load forecast methodology. What are the changes?

Scenario/Risk Analysis

Models

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.

Method

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.

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 price for CO2 caused the Rockport decisions to change.

Issues Involving I&M's Analysis

There is little mention of the value of flexibility in the resource plan. In reality, one would expect the utility to change course with their resource plan if they discovered that the world was not turning out like they originally thought it would. For instance, they may reconsider their plans regarding Rockport if significant carbon restrictions were put in place.

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 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.

Energy Efficiency Resources

The energy efficiency discussion in chapter 4 begins by noting the substantial changes in lighting standards as a result of the Energy Independence and Security Act of 2007 (EISA 2007). I&M says the EISA 2007 requires screw in light bulbs be 25% more efficient than traditional bulbs by the end of 2013 which has resulted in the typical 100, 75, and 60 watt incandescent light bulbs being phased out. Compact fluorescent bulbs (CFL) currently represent an additional savings over the standard and there remain other alternatives to meet the standard. In 2019, however, the standard increases again and precludes any options that are less efficient than CFL bulbs. Commercial T-12 lights have been prohibited from manufacture or import since mid-2012. As a result, the replacement of T-12 lighting with T-8 has become the standard for commercial sector lighting programs nationwide.

According to the IRP (p. 76), the long-term load forecast recognizes the changed lighting standards and assumes all lighting will be at the mandated standards.

Energy Efficiency Modeling Methodology

Because of the lighting standards, I&M believes that lighting programs will be less of a factor going forward so the prospects of meeting the energy efficiency levels contemplated in the Phase II DSM Order are diminished. As a result, "the load forecast reflects I&M's current estimate of what is likely achievable." Similar language is found on page 8 where I&M states the IRP includes energy efficiency programs designed to comply with the Phase II DSM Order requirements, to the extent practicable.

I&M says it is seeking new market transforming technologies and programs to supplant reliance on lighting as the foundation for energy efficiency, but I&M's ability to deliver cost effective programs will be challenged in the foreseeable future (p. 79).

I&M goes on to say "this plan reflects current program impacts as well as impacts from as yet undefined future programs but at levels required for forecasted expected performance in Indiana and target compliance in Michigan." (p. 80) Load shapes that best replicate current and likely future programs are used to model energy efficiency program impacts. The prospective programs are extrapolated from the current mix of programs and measures.

I&M used data from Efficiency Vermont to evaluate a "comprehensive portfolio of measures necessary to achieve large energy reductions." (p. 90) The energy efficiency resource options developed using the Efficiency Vermont information were made available to *Plexos* after 2019 for optimized portfolios. Two optimized resource portfolios were developed – one based on the old load forecast and the other based on the new load forecast. Each optimized portfolio added 249 MW of DSM over the period 2020-2033. (p. 182)

In an effort to validate the energy efficiency resources included in the load forecast, a scenario was run that made EE resources available beginning in 2014 relative to a load forecast that assumed no energy efficiency resources. (p. 91)

Comments and Unanswered Questions

The methodology to review energy efficiency programs and measures as described in the IRP leaves a number of unanswered questions:

1. I&M does not explain in the IRP what the "forecasted expected performance in Indiana" for energy efficiency programs is. Nor does I&M explain or demonstrate how this level was established.
2. How was the load forecast modified to reflect the impact of energy efficiency trends and programs? The reader assumes this was done for the residential and commercial sectors by adjusting the Statistically Adjusted End-Use Model (SAE) component of each model, but the methodology and data adjustments are not discussed.
3. How does the industrial load forecast model reflect the impact of existing energy efficiency programs?

4. I&M used data from Efficiency Vermont, but does not specify the exact information used and how it was modified for use in Indiana.
5. I&M validated the load forecast by using the *Plexos* model to optimize energy efficiency resources starting in 2014, but does not specify the results. The reader is left to assume the load forecast was "validated" but it is unclear what exactly that means.
6. Do the extrapolated prospective DSM programs include impacts representative of the current lighting programs? If yes, is this a reasonable assumption given the impact of lighting efficiency standards discussed by I&M in the report?

In the end, the reader of I&M's IRP has little understanding of the levels of energy efficiency included in the resource plan, how these levels were derived, and the data on which the energy efficiency analysis was based.

Treatment of Distributed Generation

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.

<u>Assumptions</u>

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 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.

Results

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 appears 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. How did I&M derive what it thought was likely to occur?

Duke Energy Indiana

Load Forecast Methodology

Duke Energy Indiana (DEI) used an econometric modeling technique to develop forecasts of both energy sales to broad customer sectors and system peak demand. The forecasting methodology appears to be reasonable but the 2013 IRP contains fewer details than their 2011 IRP and there are some changes to data sources and methodologies with no accompanying explanation for the change.

An Example of Lesser Detail

With respect to the residential sector, both the 2011 and 2013 forecasts use two components to forecast energy: the number of residential customers and energy use per customer. The forecast of total residential sales is developed by separately estimating and then multiplying the forecasts of these two components.

According to the 2013 IRP, the number of electric residential customers is affected by population and real per capita income. Because the number of customers will change gradually over time in response to changes in population and real per capita income, the adjustment process is modeled using lag structures (pp. 26 & 27).

For residential use per customer, the 2013 IRP says the key drivers are real per capita income, real electricity prices, and the combined impact of numerous other determinants. These other determinants include the saturation of air conditioners, electric space heating, other appliances, efficiency of those appliances, and weather.

The 2011 IRP included the following information in addition to similar written explanations and descriptions used in the 2013 IRP:

> (1) Number of Residential Customers =
> f (Service Area Population, Real Per Capita Income).
> where Real Per Capita Income =
> f (Service Area Total Personal Income/Service Area Population/CPI),
> f = function of.
>
> (2) Energy usage per Customer =
> f (Real Income per Capita * Efficient Appliance Stock,
> Real Marginal Electric Price * Efficient Appliance Stock,
> Saturation of Electric Heating Customers,
> Saturation of Customers with Central Air Conditioning,
> Saturation of Window Air Conditioning Units,
> Efficiency of Space Conditioning Appliances,
> Billed Cooling and Heating Degree Days).

As noted above, the information in the 2013 IRP forecast documentation lists the key drivers of customer use of electricity and other determinants. The format used to present the 2011 residential energy forecast provides more information:

1. There is an "Efficient Appliance Stock" index.
2. The real marginal price of electricity is used.
3. The Efficient Appliance Stock index is used in two different interactive variables.
    a. It is multiplied by Real per Capita income
    b. It is multiplied by the Real Marginal Electric Price

These inputs may be used in the 2013 residential energy forecast but it is not clear given the information presented.

This raises a number of questions:

1. Is the equation specification essentially the same between the 2011 IRP and the 2013 IRP?
2. If yes, how is the Efficient Appliance Stock estimated?
3. The 2011 IRP refers to the real marginal price of electricity while the 2013 IRP refers to real electricity prices. Is there a difference in how the real electricity price is calculated between the 2011 and 2013 IRP load forecasts?

Range of Forecasts

In generating the high and low forecasts for the 2011 IRP, DEI used the standard errors of the regression from the econometric models used to produce the base energy forecast. The bands are based on a 95% confidence interval around the forecast which equates to 1.96 standard deviations. These calculations were used to adjust the base forecast up or down, thus providing high and low bands around the most likely forecast.

In contrast, the first five years of the forecast in the 2013 IRP used high and low economic forecasts to develop high and low load forecasts. Beyond year five, high and low load forecasts were developed using statistical bands at the 95% confidence level. The use of economic drivers in the near term to create forecast bands is an improvement over the use of only statistical bands.

Data Changes

DEI moved from the use of aggregating county level data to state level data without explaining why. The reader is left to assume that the state level data was easier to develop and gave better or similar results compared to the use of county level data in the forecasting process. The affected data includes employment, income, and population.

Scenario/Risk Analysis

Models

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.

Method

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. This seems to have been done prior to the modeling in System Optimizer, which means that the retire vs. retrofit decision was not made within the framework of the portfolio optimization. The decision was made with the specific scenario in mind, so tighter regulations result in more retirements.

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. It appears 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 the methodology for making those adjustments. The Planning and Risk model does not do this, so another method would be needed, such as an ad hoc method or running it through System Optimizer beforehand.

Issues Regarding DEI's Analysis

The analysis of unit retirement decisions is not as clear as it could be and leaves a number of unanswered questions:

1. What criteria were used to determine the "most at-risk" units?
2. What model was used to perform the retirement analysis? The beginning of this chapter states the models used in the resource selection chapter are the System Optimizer model and the Planning and Risk production cost model.
3. Were the retirement decisions locked-in or hardwired for each scenario in the optimization model, such that a different scenario means a different set of retirement decisions was hardwired?
4. Assuming the optimization model was not used in the retirement analysis, is there a possibility when you separate the retirement decision from the new resource decision that the hardwired retirement decision will dictate the new resource selection? 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.

Another area that could be improved is scenario development. DEI 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. DEI 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 DEI'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, DEI's analysis was limited to the development of three resource portfolios whose performance was modeled under each scenario and a number of sensitivities. As is noted above, for a couple of the sensitivities it is not known if necessary changes were made to the resource portfolio and, if so, how these changes were made. 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, as noted above, 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 DEI'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.

There is little mention of the value of flexibility in the resource plan. In reality, one would expect the utility to change course with their resource plan if they discovered that the world was not turning out like they originally thought it would. For instance, they would likely revisit their retirement options for coal 15 years from now under the Traditional Portfolio if the world is looking more like the Environmental Focus scenario. Thus, there is value in having a resource plan that allows you to change course without substantial sunk costs. Duke does mention the importance of the short-term actions and that all three portfolios are quite similar in the short term.

Energy Efficiency Resources

The optimization process for each scenario was restricted by hardwiring the impact of energy 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). 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. The assumed energy efficiency load impacts for each scenario are shown in Tables 4-A, 4-B, and 4-C.

The discussion of energy efficiency is limited and no foundation was laid for why DEI chose to assume the three different levels of EE impacts that were hardwired in the optimization process. The information that is presented focuses on the history of the programs and a reasonably detailed

description of the current EE programs being implemented in the 2013-2014 time period. Cost effectiveness was not addressed except to present cost effectiveness test results for Core programs from Cause No. 43955. Also, there is no discussion of how the programs might evolve over time as new federal lighting standards go into effect and change the marketplace.

DEI's discussion also notes the load forecast incorporates the impacts of historical energy efficiency in the baseline forecast; nothing more is said (p. 54). Additional discussion of this point that answers the following questions would be helpful:

1. How does the load forecast incorporate the impacts of energy efficiency?
2. Are these impacts captured by the use of a statistically adjusted end-use model? Are the EE impacts captured some other way?
3. Can the load forecast adequately capture the impacts of the very recent large ramp-up in energy efficiency programs, especially given the Core programs did not begin full program delivery until January 2012?

Renewables and Distributed Generation

The discussion of distributed generation 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 DEI says no additional cogeneration units that impact the load forecast are assumed to be built or operated within the DEI service territory over the forecast period. DEI 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. DEI 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, DEI 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, DEI 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. According to DEI, solar is the least expensive but has a 20% capacity factor and has greater contribution at system peak than does wind. Wind is a close second in cost-effectiveness but is intermittent. Biomass is recognized by DEI as being a baseload generation option and is dispatchable, but is higher cost than wind.

The renewables technologies considered in the resource portfolio optimization model are solar, wind, and bio-methane. Wind is modeled in 50 MW blocks, solar 10 MW blocks, and bio-methane in 2 MW blocks.

DEI 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 DEI's treatment of renewable energy and DG in the IRP:

1. DEI seems to imply that 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. DEI 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. To the extent the effects of customer-owned generation is not reflected in the load forecast, DEI 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.

Indiana Municipal Power Agency

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.

Load Forecast

IMPA's approach to load forecasting seems currently to be appropriate for its system. As a basis for the IRP, IMPA developed a 20-year monthly projection of peak demands and annual energy requirements for each of the five load zones it serves. The forecasts for each zone are added together to get the IMPA forecast for energy and peak demand. The energy model uses CDD, HDD, and economic variables as independent variables. For the demand model, the load zone coincident peak demand is the dependent variable. The independent variables include temperature build-up during summer months, minimum monthly temperatures for winter months, average monthly temperatures during the spring and fall months, and various economic variables.

Load forecast uncertainty is addressed a couple of different ways. The first addresses uncertainty in the economic forecast by developing high and low economic forecasts. The high growth case increased the annual growth rate in demand and energy by .44% and .54% respectively relative to the base economic forecast. The low growth case lowered the growth rates by .40% and .50%, respectively.

IMPA also evaluated the uncertainty associated with weather variations. Two extreme weather peak demand scenarios were developed for each load zone. The baseline peak demand and energy requirements are based on average weather conditions. Extreme weather demand scenarios are based on the most extreme weather that occurred during each month over the period 2003 – 2012. The extreme scenario pushes peak demand 4% higher than normal weather in 2014 and the mild weather scenario reduced peak demand by 3%.

Questions and comments regarding the load forecast:

1. The first part of the 2013 IRP mentions that the real electricity price (measured as the average wholesale prices for each supply area) was included in the forecasting models. However, there

is no mention in the text or statistics reports about the use of this variable in the "2013 Load Forecast" in Appendix D.

2. The approach of calculating the mean temperature from the daily maximum and minimum temperatures is commonly used. However, has IMPA considered calculating the average temperature by using all the daily observations instead of only the maximum and the minimum temperatures? Although this would require the use of more data, this approach could provide a better estimation of the mean temperature and improve the outcome of the model.
3. The build-up temperature data was calculated by the summation of the coincident peak date maximum temperature times 10/17, previous day maximum temperature times 5/17 and the second day back maximum temperature times 2/17. According to IMPA, this variable had a greater statistical significance in the demand models than maximum temperature. How were the factors (10/17, 5/17, and 2/17) determined?
4. Does IMPA use one model with two different variables – one for winter and the other for summer – included in the same model for estimating peak demand? If yes, why not use one model to estimate summer peak and another model to estimate winter peak?
5. Why is U.S. Real Gross Domestic Product (GDP) used as an independent variable used in the forecast model instead of Indiana Real Gross State Product or a regional GDP variable? The use of a variable at a more regional level could better reflect the different characteristics of that specific region in the model.
6. In the 2011 IRP, IMPA mentions that future changes will include the effects of increased appliance energy efficiencies mandated by the Energy Policy Act of 2005 and higher prices from new environmental requirements. Are these effects already considered in the 2013 IRP? There are no comments about it in the current IRP.
7. Will the current load forecast methodology be sufficient when there is a need to better understand what is happening to consumption across different customer classes and the drivers of these changes? If yes, why? Is there a need going forward for greater customer class level information if, for example, energy efficiency, DR, and DG programs are to be properly modeled and considered in the resource planning process?

Scenario/Risk Analysis

<u>Models</u>

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.

Method

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.

Other Notes and Comments

The definition of risk as the difference between the average stochastic solution and the deterministic solution may understate the importance of the extreme outcomes. Limitation of risk measurement to this one definition might be problematic but IMPA also used other 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 CO2 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. Both energy efficiency resources and renewables are hardwired in the development of the 10 resource plans used in the uncertainty and risk analysis. Demand response and DG resources do not appear to have been considered in the model.

Energy Efficiency

As noted above, the impact of energy efficiency was hardwired 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 very 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.

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 so that its ability to carry out effective long-term resource planning is not adversely affected.

DG and Renewable Energy

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 says it 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)

However, 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.

Wabash Valley Power Association

Load Forecast Methodology

WVPA uses econometric models to forecast the energy and peak demand requirements for each member separately. The separate forecasts are then summed to develop a WVPA-wide energy and peak load forecast. This methodology represents a bottom-up approach.

Residential class energy requirements are forecasted by multiplying the number of customers by the average use per customer per month. The number of residential customers is modeled as a function of the households. Average use per customer is modeled with household income, electric appliance market share, number of people per household, price of electricity, and heating and cooling degrees as independent variables.

The small commercial class includes all non-residential customers with a transformer less than 1,000 kVa. WVPA uses the same methodology as is used for the residential sector load forecast. The number of small commercial customers was modeled as a function of the number of residential customers and employment. Average use was modeled as a function of weather and retail sales per employee.

Large commercial customers are non-residential customers with a transformer larger than 1,000 kVa. The large customer forecast is provided by member cooperative staffs.

Pass-through customers are large power customers and each customer is forecasted separately. The load for these customers is not included in the total energy or peak load managed by WVPA, but is included in WVPA's total planning load since WVPA has ultimate responsibility to meet these large customers' energy requirements.

Peak demand is projected by applying an average load factor to projected energy requirements. The load factor is held constant, which assumes that energy and peak will grow at the same rate over time.

WVPA also developed four other forecasts:

1. Optimistic Economy – An econometric model of energy requirements as a function of gross regional product (GRP) and heating and cooling degree days was developed to generate a load forecast under optimistic economic conditions. WVPA says the GRP forecast was increased compared to the base case projection. "The econometric model coefficient is used to estimate the optimistic energy requirements forecast." (Section III, p. 8) The load factor from the base case forecast is applied to the optimistic energy requirements for the peak demand forecast.
2. Pessimistic Economy – Total GRP is projected to grow at a lower rate than the base case. "The same econometric GRP coefficient is then used to produce the pessimistic forecast for energy requirements." (Section III, p. 8)
3. Extreme Weather – An econometric model of energy requirements was estimated with heating and cooling degree days as independent variables. The weather coefficients were applied to the

extreme degree days to estimate extreme energy requirements. Extreme weather was defined as total degree days that have a probability of occurrence of 5%.

4. Mild Weather – the coefficients for heating and cooling degree days were applied to the mild weather data. The mild weather was based on a 5% probability.

Comments and Questions

The load forecast portion of the IRP document suffers from a lack of detail, to the point where a reader cannot tell what was done beyond a very high level. The result is there are many unanswered questions such as:

1. Does the appliance share variable included in the average use per residential customer model capture appliances other than electric air conditioning and heating market share? For example, the appliance market share discussion in section III on page 4 mentions electric water heaters and miscellaneous plug load but nothing more is said. If other appliances were included, what were they, and how were they included in the econometric model?
2. According to the discussion in Section III on page 4, the load forecast "captures the impacts associated with the Energy Independence and Security Act ("EISA") of 2007, which is a federal mandate for manufacture of more efficient incandescent bulbs beginning in 2012. These effects were modeled using assumptions developed by the EIA for their Annual Energy Outlook 2012." How was this done?
3. How are energy efficiency and DR captured in the load forecast?
4. Is the impact of the energy efficiency programs discussed by WVPA in Section II on pages 18-20 considered in the forecast? If yes, how?
5. Is the impact of existing DR programs considered in the forecast? If yes, how?
6. How do the member cooperatives develop their large commercial class forecast? Does WVPA check on the reasonableness of the forecast provided by its members?
7. What were the results from the updated 2013 residential appliance saturation study? Were the results comparable to the data used for the 2011 IRP?
8. Why was a separate forecast for pass-through customers used in 2013? Did this treatment differ from that in the 2011 IRP and, if so, why? How is the load for each customer forecasted?
9. Did WVPA use one method to prepare a base load forecast and a different method to prepare the Optimistic Economy and Pessimistic Economy forecasts? If yes, why?

Scenario/Risk Analysis

Models

WVPA uses the MIDAS planning model from Ventyx for its production cost estimates. These estimates are fed into a custom-built financial model to determine expected revenue requirements (for production costs only). WVPA has access to stochastic modeling through its relationship with ACES, but it appears that no stochastic modeling was performed for the IRP.

Method

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 fare 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 does not appear to have been used to develop resource plans that were then subject to further analysis.
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.
3. Was a different resource plan developed for each scenario? If yes, why was the information not presented?
4. Were only three expansion plans developed – the base case, high economic growth, and low economic growth?
5. Was the Base Resource Plan the only capacity expansion plan modeled using the nine scenarios?
6. Why were only a few of the modeling results presented?
7. WVPA says that it contracts with ACES to provide risk management functions, including stochastic modeling. Why was stochastic modeling mentioned but not used in the development of the IRP? How does WVPA use stochastic modeling? What type of risk management functions is performed by ACES on behalf of WVPA, and how do these functions affect WVPA's 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."

Despite this statement, WVPA does little to address the flexibility of its plan going forward and no information is given to draw a different conclusion. This statement indicates that WVPA might have performed more and different types of analysis which was not discussed in the report.

Energy Efficiency Resources

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."

A reader of the IRP report can only conclude that the effects of energy efficiency in general and the impacts of the WVPA-sponsored EE programs in particular are ignored in the development of the resource plan.

DG and Renewable Energy

WVPA discusses in Section II on pages 22-23 how it handles end-consumer distributed generation, 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 distributed generation 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 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.

IRP Public Advisory Process Review

Use of meeting facilitators

Both utilities used facilitators to keep the meetings on schedule while trying not to unnecessarily restrict conversation.

Meeting Registration

Both utilities used an on-line process to register attendees and to provide meeting materials.

Duke Energy

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 am registration and a 9:30 am workshop start. The agenda used at the meeting had an 8:30 am registration and a 9:00 am workshop start. At least two attendees arrived at 9:15 am to discover that the workshop had already started.

Indiana Michigan Power

There were no apparent problems with their process.

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, DEI had a couple of meetings where a customer showed up to see what is going on.

Duke Energy

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 is 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

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 distributed generation 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

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

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, DEI 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

Duke Energy

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.